



Virginia Solar Pathways Project

Economic Study of Utility-Administered Solar Programs: Soft Costs, Community Solar, and Tax Normalization Considerations

Emerson Reiter, Travis Lowder, Shivani Mathur,
and Megan Mercer

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Strategic Partnership Project Report
NREL/TP-6A42-65758
June 2016

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List of Acronyms

ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy-Efficient Economy
APS	Arizona Public Service
BOS	balance of system
BPU	Board of Public Utilities
CFC	National Cooperative Services Utilities Cooperative Finance Corporation
CREST	Cost of Renewable Energy Spreadsheet Tool
DevCo	development company
DG	distributed generation
DOE	U.S. Department of Energy
DERP	Distributed Energy Resource Program
DSIRE	Database of State Incentives for Renewable Energy
EPC	engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
H1	first half (of a given year)
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
IOU	investor-owned utility
IPP	independent power producer
IRR	internal rate of return
IRS	Internal Revenue Service
ITC	investment tax credit
KIUC	Kauai Island Utility Cooperative
kWdc	kilowatts direct current
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of electricity
LLC	limited liability company
MACRS	modified accelerated cost recovery system
MWac	megawatts alternating current
MWdc	megawatts direct current
MWh	megawatt-hour
MECO	Maui Electric Company
NCEMC	North Carolina Electric Membership Corporation
NCSC	National Cooperative Services Corporation
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PowerCo	power company
PII	permitting, inspection, and interconnection
PLR	private letter ruling
PPA	power purchase agreement
PSC	Public Service Commission
PSE&G	Public Service Enterprise Group
PTO	permission to operate
PUC	public utility commission
PV	solar photovoltaic

REC	renewable energy certificate
RMI	Rocky Mountain Institute
RPS	renewable portfolio standard
SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SEPA	Solar Electric Power Association
SMI	Solar Market Insight
SREC	solar renewable energy certificate
SPVP	Solar Photovoltaic Program
TEP	Tucson Electric Power
TPO	third-party ownership
TVA	Tennessee Valley Authority
UOG	utility-owned generation
VNM	virtual net metering
VSP	Virginia Solar Pathways Project
WACC	weighted average cost of capital
Wdc	watts direct current

Executive Summary

This report presents economic considerations for solar development in support of the Virginia Solar Pathways Project (VSPP), an effort funded by the U.S. Department of Energy (DOE) SunShot Initiative that seeks to develop a collaborative utility-administered solar strategy for the Commonwealth of Virginia. The results presented are intended to be considered alongside the results of other studies conducted under the VSPP that evaluate the impacts of solar energy on the electric distribution, transmission, and generation systems in Virginia.

Three major topics are considered in the report: (1) the potential for soft cost reductions through utility-administered solar, (2) utility involvement in community solar development in the Southeast, and (3) the financial impacts of tax normalization policy on utility-led solar development. These topics were selected for investigation because of their potential to reduce the installed costs of solar energy and the pivotal role electric utility companies play in each of the three.

The potential for reductions in soft costs through utility-administered solar was examined in two parts. First, we used a web-based survey to collect information on current soft cost levels and business practices in Virginia and solar markets in surrounding states. Survey respondents indicated a lower level of soft costs for residential installations than reported in recent literature, a fact that may be partly attributable to the larger average system size in this survey. Soft cost levels for commercial and utility-scale projects were in line with historical levels. Additionally, survey responses indicated low uptake of several business practices that are seen as key to reducing soft costs to achieve SunShot installed cost targets for solar PV systems, particularly in the area of customer acquisition.

Second, we aligned the gaps in uptake of soft cost reduction strategies with demonstrated utility capabilities in solar program execution. These capabilities were determined through a set of interviews with staff from several utilities that detail the precise division of responsibilities between utilities and partnering entities for each soft cost business process. This comparison of existing installer strategies and demonstrated utility capabilities revealed that customer acquisition and insurance are two areas in which utility involvement might offer cost reductions. These results are echoed by the results of a recent survey of solar installers conducted by EnergySage, which revealed major demand within the solar industry for enhanced capabilities in customer acquisition.

We then considered community solar, a solar development model in which multiple customers acquire rights to the energy or capacity of a shared solar installation in order to realize environmental, economic, or other benefits. This topic was chosen due to (1) its potential to reduce solar energy costs through the economies of scale of larger installations and (2) its ability to reach customers who might not be able to procure solar energy through other means. We developed a set of regional “readiness criteria” for community solar that incorporates information about state-level deployment of solar energy technologies generally as well as enablers of community solar programs specifically. We found that southeastern states lack the community-solar-supporting policies of some leading states, such as virtual net metering and special supporting provisions of state renewable portfolio standards. However, we also note that three of the region’s states rank in the top 10 in the nation by number of renter households. These

large renter populations present a potentially large customer base for community solar, as renters are often unable to access traditional rooftop solar systems.

We supplemented this general regional investigation with detailed descriptions of several community solar projects in the region that demonstrate the specific tactics program administrators are using. This analysis was produced through a combination of background research and direct interviews with program administrators. Our major findings were that (1) program administrators have had to proactively identify local supporting incentives to build community-solar facilities, given the region's lack of state-level incentives and low cost of electricity, (2) administrators must place a heavy focus on pricing structures and customer engagement to encourage subscribers, and (3) cost is the primary driving factor in site selection (rather than public visibility).

Finally, we examined tax normalization, the method by which regulated electric utility companies are required to return certain tax benefits to their ratepayers. If all other factors are equal, this regulation has the ultimate effect of increasing the cost of solar energy from utility-owned facilities as compared to those developed by an outside entity. This is because the realization of tax benefits, such as the investment tax credit and accelerated depreciation, is spread across the life of the solar asset, which causes a loss in value of these benefits due to the time value of money. Comparing basic financial models of solar energy projects in Virginia with and without tax normalization reveals that this policy can increase the cost of solar energy by over 50%, all else being equal. We discuss several unique approaches being explored to manage tax normalization obligations, and we highlight the experiences of several utilities in dealing with this requirement. This topic will remain especially relevant in the near future given the December 2015 extension of the federal investment tax credit for solar energy projects.

This analysis seeks to deliver decision-grade information on several economic considerations for the design of utility-administered solar programs, in accordance with the goals of the VSPP. The findings that follow are not intended to be considered in isolation but rather in combination with the other studies and technical reports produced under the VSPP. Further, no discussions of policy that follow constitute recommendations but rather seek to inform the relevant decision-makers at the local and state levels.

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1 Introduction

In recent years, the deployment of solar photovoltaic (PV) systems has increased dramatically in the United States, with total capacity additions being second only to natural gas-fired generation in 2013 and 2014 (Munsell 2015). Despite this rapid growth, current solar PV deployment trajectories are not projected to be sufficient to achieve the ambitious deployment and cost goals set forth in the U.S. Department of Energy’s (DOE) SunShot Initiative. In recognition of this fact, DOE launched the Solar Market Pathways program, which will “take a variety of approaches to develop actionable strategic plans to expand solar electricity use for residential, community, and commercial properties,” with the goal of developing replicable approaches to deployment that can be applied beyond the specific project area.¹

One of the 14 projects supported by the Solar Market Pathways program is the Virginia Solar Pathways Project (VSPP). Led by Dominion Virginia Power, the main objective of this effort is to develop a collaborative utility-administered solar strategy for the Commonwealth of Virginia. According to the statement of project objectives, the VSPP team will:

- Integrate existing solar programs with new options appropriate for Virginia’s policy environment and broader economic development objectives
- Promote wider deployment of solar within a low rate environment
- Serve as a replicable model for use by other states with similar policy environments, including but not limited to, the entire Southeast.

The bulk of the analysis necessary to achieve these goals is to be delivered through a series of studies, commissioned by Dominion Virginia Power using Solar Market Pathways funding, to study key topics for system-wide solar energy integration.

This document comprises the final report for the third VSPP study. The National Renewable Energy Laboratory (NREL) was tasked with completing this study, which focuses on economic considerations of solar deployment, particularly in the areas of cost barriers, business models, and new value opportunities. The report presents NREL’s findings related to the three key issues identified by Dominion Virginia Power for detailed investigation:

- **Soft costs of solar PV installations:** “Soft costs” encompass all non-hardware costs related to the development of solar energy facilities. These soft costs include all labor for installation, permitting, interconnection and financing, permitting and interconnection fees, costs of financing, and ongoing costs, such as insurance and operations and maintenance (O&M) costs. This area of costs of solar installations is widely cited as a major driver of total installed costs in the United States and is one that other nations have demonstrated can be lowered successfully.
- **Community (or “shared”) solar programs:** This term describes solar programs in which multiple customers acquire rights to the energy or capacity of a shared solar installation in order to realize environmental, economic, or other benefits. Recent literature on this topic has touted many benefits, including reduced cost to and effort

¹ For more information on this and other Solar Market Pathways programs, see the official site: <http://energy.gov/eere/sunshot/solar-market-pathways>

required from customers, greater electrical benefits due to strategic site selection by the utility, and access to untapped and unaddressed customer segments (Feldman et al. 2015).

- **Tax normalization:** This term describes the accounting method that specifies the method and timing of how regulated utilities can return certain tax benefits to their ratepayers. This regulation can impact the value of certain tax benefits of owning solar energy facilities, such as the investment tax credit (ITC) and accelerated depreciation.

Though these topics deal with a diverse set of issues related to solar PV systems, they are united by two key commonalities, both of which are pivotal to the VSPP’s mission of “developing a collaborative utility-administered solar strategy.” These commonalities are:

1. **Potential to reduce cost of solar energy systems:** Creative solutions to this report’s three main topics could reduce the total installed cost of solar PV systems, as measured in dollars per watt (\$/W), as well as the cost of energy delivered from those systems, as dollars per kilowatt-hour (\$/kWh). Of these three topics, soft costs can have the most direct impact on solar costs, as cost reductions in this area directly reduce installed costs. However, community solar can also offer benefits by increasing the economies of scale and improving the siting of distributed solar facilities, while strategies to mitigate tax normalization effects can increase the value of tax incentives for solar, thereby reducing financing costs and total costs. Solar PV cost reductions (from any source) are critical in Virginia and other southeastern states, where energy from solar PV must compete with low-cost sources such as coal, nuclear, and natural gas on the bulk power system and with low electricity rates at the retail level.
2. **Key roles for electric utility companies:** All three topics discussed in this report directly impact or can be impacted by electric utilities. In the area of soft costs, utilities may have unique business practices or structures that allow them to help reduce the costs of solar energy systems. Utilities are also key facilitators of community solar programs and must navigate tax normalization requirements for capital investments in order to equitably return the value of tax benefits of solar energy systems to ratepayers. This aspect of the report is emphasized to support the VSPP mission and to explore the expansion of electric utility participation in solar development in the United States generally.

The topics of soft costs (Section 2) , community solar (Section 3), and tax normalization (Section 4) are treated in similar fashion in the following discussion. Each section first provides background on the current topic, recapping existing literature where appropriate. Next, each section provides additional context by relating the state of current practice in the given topic area. With background and current context developed, each section then delivers decision-grade information to support the development of utility-administered solar strategies, including novel data, frameworks, and case studies. Finally, each topic is analyzed and discussed based on its implications for the cost of solar energy systems and options for utility engagement.

It is important to note that this report does not endeavor to make recommendations with regard to policy development, regulatory action, or business strategies. Nor does this report address the integration of solar into the distribution, transmission, and generation systems; these topics are addressed directly in other studies executed under the VSPP. Rather, it seeks to present information relevant to the design of utility-administered solar programs and for consideration and action by lawmakers, regulators, government officials, and utility and solar industry staff.

2 Soft Costs and Business Practices

Soft costs are any costs related to deployment of solar technologies that are not direct hardware costs. These costs are critical because of their contribution to overall installed costs (roughly 50% of total residential and commercial PV installed costs) and because of the potential for reductions in this area (Friedman et al. 2013; Shiao 2015). While hardware cost reductions may rely on material science breakthroughs, design innovations, or manufacturing process improvements, soft costs can be addressed by new software for customer acquisition or system design, innovative business practices in construction or project financing, or streamlined regulatory and permitting requirements.

Several potential avenues for soft cost reductions in the United States have been suggested through comparisons of installed costs of PV systems in the United States and other countries. Specifically, as solar hardware has become more commoditized, all nations are facing roughly the same hardware costs; thus, the variation in total installed prices has become more strongly attributable to differences in soft costs. A 2011 comparison of soft cost levels in Germany and the United States found that customer acquisition costs in Germany are one-tenth what they are in the United States, as German firms benefit from a combination of greater use of lead-generation partnerships, higher bid acceptance rates, and the “mainstreaming” of residential solar energy systems (Seel, Barbose, and Wiser 2014). The same report also found that German rooftop installations required roughly half as many installation labor hours as U.S. installations, despite having larger median system sizes. A 2016 report comparing Japanese and U.S. residential and small commercial solar installations showed cost advantages for Japanese installers in customer acquisition expense and in permitting, inspection, and interconnection (PII) fees and labor hours (Friedman, Margolis, and Seel 2016). Finally, a detailed activity-based study by the Rocky Mountain Institute and Georgia Tech Research Institute showed per-kW labor hour requirements that are 50% lower in Australia than the United States (Calhoun et al. 2014).

Given the potential for business practice innovations to substantially impact soft costs, and because of the VSPP’s mission to explore utility-administered solar options, our analysis examines the topic of soft costs in relation both to practices in both the existing U.S. solar industry and to utility-administered solar project development. Given their existing prominent roles in the U.S. electrical system and large organizational and financial resources, solar deployment models incorporating greater involvement from electric utilities could represent a significant opportunity for increasing PV development in the United States. While we present results of a regional soft cost survey of solar installers, we do not directly develop similar estimate for utility-administered solar development due to the relative scarcity of such programs and the confidentiality of cost information. Instead, the bulk of the information we present represents a comparison of business practices used by the solar industry and utility-administered solar programs in areas that impact soft costs. Where survey results indicate that solar companies may not be adopting all possible soft cost reduction opportunities, we report on ways that utility solar programs have interacted with solar industry partners in these areas.

Section 2.1 presents historical information on the concept of soft costs and past efforts to quantify them. Section 2.2 recounts the current status of industry soft costs, providing a historical baseline for the soft costs faced by non-utility solar industry participants. Next, Section 2.3

outlines the methodology for investigations of solar industry and utility involvement with soft costs; the results of this work are subsequently presented in Section 2.4. Finally, the discussion provided in Section 2.5 draws on (1) historic and current levels of industry soft costs, (2) general utility models of engagement in solar development, and (3) specific utility experiences in soft cost areas to offer considerations for the design of industry-utility interactions to reduce the soft costs of solar deployment.

2.1 Background

Within the literature on solar PV system costs in the United States, the presentation of soft costs has evolved toward increased specificity and disaggregation. Several reports published on PV pricing do not disaggregate soft costs at all, though they emphasize the importance of this category as a barrier to large-scale U.S. PV deployment (Brooks 2011; Rose et al. 2011; Varnado and Sheehan 2009; Pitt 2008). Similarly, the *Tracking the Sun* series of reports, published by the Lawrence Berkeley National Laboratory (LBNL), collects, synthesizes, and releases information on U.S. historical PV installed price data. Though the LBNL reports focus on the total installed cost of solar PV, the most recent installment in the *Tracking the Sun* series attributes declining PV installation pricing to reducing soft costs in the areas of marketing and customer acquisition, system design, installation labor, permitting and inspection costs, and installer margins (Barbose et al. 2013). Other studies examine soft costs broadly with a minimal degree of disaggregation (Smith and Shiao 2012; Bony et al. 2010). More recent work on soft costs has been led by NREL and LBNL, and it disaggregates soft costs into different components and provides benchmarks for soft costs (Ardani et al. 2012; Friedman et al. 2013).

From a forward-looking perspective, the DOE SunShot Initiative has set long-term price targets for solar facilities in the United States that break out the share of total costs attributable to soft costs. For 2020, DOE set its total installed cost targets in 2010 dollars at \$1.50/W for residential systems, \$1.25/W for commercial systems, and \$1/W for utility-scale systems (DOE 2012).² Soft costs are expected to total \$0.65/W for residential systems (43% of total costs), \$0.44/W for commercial systems (35%), and \$0.22/W (22%) for utility-scale systems (DOE 2012). By comparison, results from the most recent NREL/LBNL installer survey and cost-modeling analysis indicate that in 2012, soft costs totaled \$3.19/W for a 5-kW residential systems and \$2.90/W for small commercial systems (≤ 250 kW), representing approximately 64% of the average total residential system price and 57% of the average small commercial system price (Friedman et al. 2013).

The literature for utility-scale solar projects is less extensive than that for residential and commercial systems, but LBNL's 2015 report on utility-scale solar project costs compiled past estimates of soft costs from several sources (Bolinger and Seel 2015). Soft costs in these cases were aggregated at a high level in two categories; one covered design, EPC, labor and PII efforts, while the other included all other non-hardware costs. These soft cost estimates from LBNL, NREL, and Bloomberg New Energy Finance ranged from \$0.61/W for a 100-MW single-axis tracking project to \$0.90/W for a 20-MW single-axis tracking project (34% to 48% as share of total project costs). This variation suggests that utility-scale projects can achieve partial economies of scale in soft costs, as some soft costs remain relatively fixed regardless of installed capacity (e.g., PII labor) while others do not (e.g., construction labor). Nevertheless, the reported

² All cost values in Section 2.1 are reported in 2010 dollars for comparability to SunShot targets.

soft costs for utility-scale solar PV facilities have been lower than the soft costs of residential and small commercial installations on both an absolute basis (\$0.61/W–0.90/W vs. \$3.19/W or \$2.90/W) and as a share of total installed cost (34%–48% vs. 64% or 57%). Still, the recent results across all sectors indicate that significant progress is needed to achieve the SunShot soft cost targets for 2020.

Beyond survey approaches, GTM Research has developed a bottom-up modeling methodology in which they incorporate information from major national PV installers. This modeling relies on a set of assumptions about the modeled PV systems (e.g., residential systems at 6 kW on a flat roof) and reflects mostly cost levels from high-volume installation and engineering, procurement, and construction (EPC) companies (GTM Research/SEIA 2015). Through this exercise, GTM Research developed estimates of three soft cost components: direct labor; engineering and permitting, inspection, and interconnection (PII); and supply chain, overhead, and margin. The total of these components captures all PV system soft costs, which were most recently reported in Q3 2015 at \$2.06/W for residential installations, \$0.91/W for commercial installations, and \$0.45/W for single-axis tracking utility-scale projects (GTM Research/SEIA2015).

2.2 Status

2.2.1 Solar Industry

2.2.1.1 Total Soft Costs

Figures 1 - 3 show historical soft costs from various sources as well as the SunShot targets for 2020. Data are compiled from numerous reports, including Goodrich, James, and Woodhouse (2012), Ardani et al. (2012), Ardani et al. (2013), Friedman et al. (2013), Bolinger and Seel (2015), Shiao (2015), and multiple GTM Research/SEIA Solar Market Insight reports. In Figure 2, small commercial systems are those under 250 kW in size, while large systems are those above 250 kW. Though the values depicted in these figures emerge from varied survey and modeling techniques, they provide valuable context and insight into long-term trends.

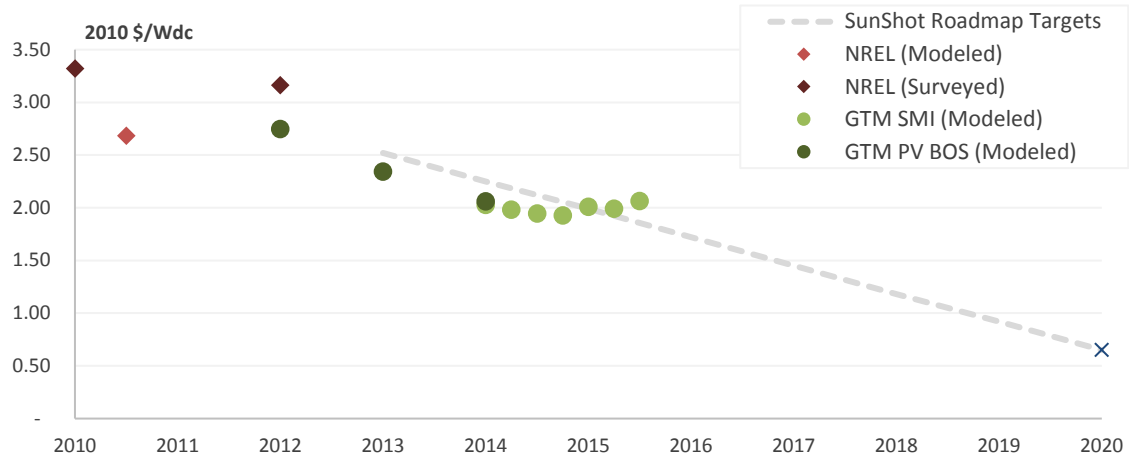


Figure 1. Historical estimates of total residential installation soft costs

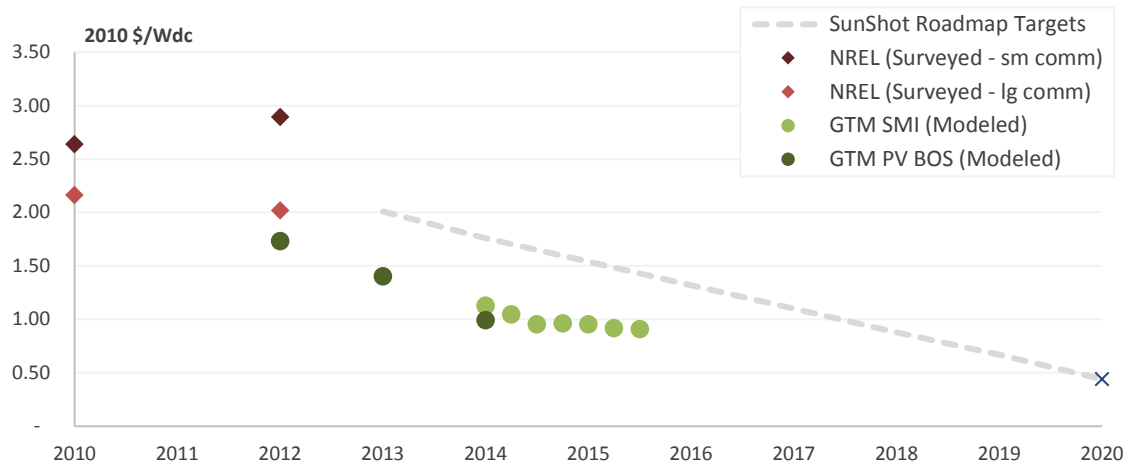


Figure 2. Historical estimates of total commercial installation soft costs

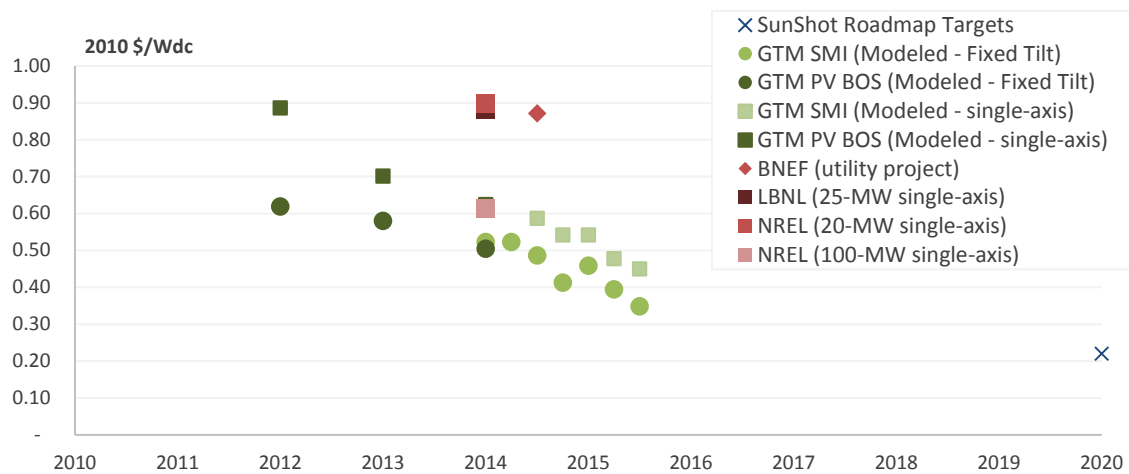


Figure 3. Historical estimates of total utility-scale installation soft costs

2.2.1.2 Elements of Soft Costs

As the disaggregation of soft costs has proceeded in the literature over the years, the terminology used to define areas of soft costs has also evolved. Barbose et al. (2011) attributed solar PV installed system prices to costs of the module, inverters, and “others.” Rocky Mountain Institute analyzed balance-of-system (BOS) costs, and included soft costs, as “business processes” costs, which consisted of all the enabling processes associated with a PV project, including customer negotiation, contracting and financing, permitting and regulatory approvals, and utility interconnection (Bony et al. 2010). Goodrich et al. (2011) used a bottom-up approach to benchmark PV system prices and reported detailed component costs for installation materials, electrical labor, installation labor, supply chain costs, permitting and commissioning, and installer overhead.

The NREL and LBNL data collection efforts to benchmark and disaggregate non-hardware BOS costs for residential and commercial PV systems sought to standardize the nomenclature and present the greatest level of disaggregation to date (Ardani et al. 2012; Ardani et al. 2013; Friedman et al. 2013). The categories developed in these three reports have been adopted here to the extent possible, and they include sales tax, supply chain costs, installer/developer profit, indirect corporate costs, transaction costs, customer acquisition costs, permit fees, PII labor, and installation labor. These soft cost categories were developed for and are readily applicable to solar PV systems in the residential and commercial market segments, but they require some interpretation to be applied to the utility-scale sector. Customer acquisition in the utility-scale space would encompass activities such as site assessments and power purchase agreement (PPA) negotiations, while PII might also include expenses for the construction of physical interconnection facilities.

Three major components of soft costs—customer acquisition, PII, and installation labor—have been tracked across a number of different reports over time and have been targeted for reduction in the SunShot 2020 goals. These categories each span several specific business processes:

- Customer acquisition encompasses marketing and advertising, sales calls, site visits, and contract negotiation and preparation.
- PII includes all labor associated with preparing and submitting permitting and interconnection forms, completing facility inspections, and applying for all available incentives.
- Installation labor includes site preparation, hardware pre-assembly, racking installation, module mounting and system wiring.

Figure 4 depicts soft cost values in these categories for residential PV systems as reported in NREL survey reports (Ardani et al. 2012; Friedman et al. 2013), NREL modeling reports (Goodrich, James and Woodhouse 2012), as well as information from Greentech Media research reports and NREL’s soft cost “roadmapping” efforts for DOE’s SunShot targets (Ardani et al. 2013). The values are all presented in 2010 dollars for ease of comparison to SunShot target levels. While there are significant differences in the modeling and survey methods used to derive these values over time, as discussed above, the general magnitude of these costs can be assessed in relation to long-term targets and trends. The SunShot trajectory lines indicate the industry’s anticipated future soft cost levels as of 2013, while the targets indicate roadmapped values

necessary to achieve the 2020 SunShot cost targets. The overall conclusion of these comparisons is that customer acquisition and installation labor soft cost levels are below current-year projections but will need to decline by more than 50% to reach SunShot 2020 targets, while PII costs lag even their current-year targets.



Figure 4. Summary of recent values for residential solar soft costs (2010\$ per watt DC)

Another area of soft costs for which there are less historical data is financing. Financing, overhead, and profit for residential and commercial PV installations comprise a significant share of soft costs. These costs were modeled at \$1.23/W for residential 5-kW systems and approximately \$1.76/W for small commercial (<250kW) systems (Friedman et al. 2013). One critical item to note is the relationship between third-party ownership (TPO) and soft costs. Under a TPO arrangement, an installer will construct a solar power system on a customer site, often for little or no upfront cost, and will own that asset, either leasing it to the homeowner or signing a PPA with the host. With more parties involved in a transaction under third-party models than in direct sales, increasing the complexity and costs involved in the sale (Feldman et al. 2013). As a result, TPO financial structures raise the *overall* installed costs (and soft costs) of the system, though they may increase deployment opportunities by reducing or eliminating *upfront* costs to customers.

As noted in Section 2.2.1.1, total soft costs are generally lower for utility-scale facilities due to the economies of scale achieved through larger capacity systems. These economies of scale occur in areas where activity is required per installation rather than per watt of capacity: customer acquisition, permit fees, PII labor, transaction costs, and to a lesser extent sales tax, indirect corporate costs. Installation labor does not decrease for this reason, as installation labor

scales roughly linearly with installed capacity, but it may be lower than it is in other sectors due to the relatively simpler methods of construction (i.e., ground-mounted vs. roof-mounted systems).

Most soft costs are reported on a \$/W basis because they affect the initial installed cost of the system, but more interest is now being given to ongoing soft costs, which typically can be reported in dollars per kilowatt per year (\$/kW-yr). Soft costs of this type, such as O&M and insurance costs, will affect the cost of energy from the system (\$/kWh) but not the initial installed cost (\$/W). These costs are considered as follows:

- **Operation and maintenance:** Operation and maintenance practices and approaches are not standard and are implemented in various proprietary methods. O&M costs for solar PV vary widely with geographic location, climate, type of system, system size, and other factors. These costs can include costs of inverter replacement, preventive, corrective and condition-based maintenance, insurance, property taxes, and other costs (Keating, Walker, and Ardani 2015; EPRI 2010). The O&M cost of solar PV installations is often fixed at a \$/kW-yr level over the life of a system, is small compared to the initial cost, and can vary with the size of the solar PV system being maintained. For utility-scale solar PV (> 2 MW), a survey of PV plants owned by four utilities showed an average O&M cost between \$16.9/kW-yr and \$30.2/kW-yr (Bolinger and Seel 2015). In 2013, NREL estimated fixed PV O&M costs for grid-tied distributed generation (DG) scale systems appropriate for residential, commercial, industrial, and federal facilities as \$21/kW-yr for <10kW systems, \$19/kW-yr for 10-kW to 1,000-kW systems, and \$20/kW-yr for 100-kW to 1,000-kW systems (NREL 2013). Similar levels of costs are reported in the OpenEI Transparent Cost Database, which is maintained by NREL and compiles cost estimates from a variety of research and industry sources (“Transparent Cost Database” 2015). Best practices and standards for the solar PV O&M industry have been documented by Sandia National Laboratory and NREL (Keating, Walker, and Ardani 2015; Klise, Balfour, and Keating 2014).
- **Insurance:** Photovoltaic project developers are generally required to insure their projects with property and liability coverage. The developers may include additional insurance coverage, such as environmental risk insurance, business interruption insurance, contractor bonding, or construction risk insurance. In 2010, NREL conducted an analysis on the challenges of insuring PV power projects. The study found that PV insurance costs may have been overstated largely because of the insurance industry’s unfamiliarity with PV technologies and the project development process, as well as the limited availability of historical operating data used to formulate underwriter models (Speer, Mendelsohn, and Cory 2010). The authors of the same study interviewed several large-scale PV project developers that operated projects under a PPA with a utility offtaker; these developers estimated total insurance costs during operation at roughly 0.25% of the installed system price, of which at least 90% was attributable to property insurance (Speer, Mendelsohn, and Cory 2010).

Other insurance costs are variable based on the types of coverage held, making a general cost assessment difficult. Property and liability costs during the construction phase have been estimated at \$0.09 to \$0.13 for every \$100 of a project’s replacement value (Lowder

et al. 2013). Insurance coverage for catastrophes such as floods or earthquakes can cost more than \$3 for every \$100 of replacement costs (Lowder et al. 2013). The cost of business interruption insurance has been estimated at 0.1% of replacement costs (Lowder et al. 2013). For homeowners who own their own solar PV systems, rooftop installations are generally covered under their existing homeowners' insurance policies, though coverage for residential ground-mounted systems may vary by insurer (Speer, Mendelsohn, and Cory 2010). Finally, utilities that self-insure may be able to incorporate PV facilities that they own into their existing strategy at little or no incremental cost, while utilities with third-party insurance will need to add their solar assets to their existing policies.

Warranties of various types may overlap with O&M and insurance needs. These can include a 5- to 10-year "workmanship" and materials guarantee (which warrants the physical product) and a 25-year performance guarantee (which warrants the energy produced) (Warranty Week 2011). Warranty insurance is a new risk management strategy that can be found in two forms: manufacturer coverage and system-level performance coverage (Lowder et al. 2013). Manufacturer coverage can be purchased by manufacturers to cover claims against their products that exceed their warranty reserve funds or in the event of manufacturer bankruptcy. System-level performance coverage can be acquired by an EPC contractor and pays out additional funds should the company be unable to fund performance warranty payments to its customers, including in the event of installer bankruptcy (Lowder et al. 2013).

2.3 Methodology

Determining the potential for reducing soft costs in utility-administered solar programs first requires a baseline understanding of current soft costs levels in the solar industry. Because solar industry companies may operate under differing business models, a comparison of business practices in soft costs areas is also necessary. Information in both of these areas was collected via a web-based survey. Furthermore, because utility-administered solar programs operate under different business models, a comparison of the roles of the utility in utility-administered solar programs is also vital. In-depth interviews with utility solar program administrators were conducted to produce this comparative research on utility solar programs. In addition, numerous utility solar programs were briefly profiled and categorized based on common traits. Summaries of these program designs are provided for reference in Appendix A.

2.3.1 Solar Industry

The first aspect of the soft cost investigation in this report examines solar industry soft costs and related business practices in Virginia and the Southeast at large. A web-based survey was developed to collect information from solar installers and project developers in Georgia, Maryland, North Carolina, Virginia, and Washington, D.C. These states and this city were chosen for a variety of reasons, including:

- Virginia is the main state of interest for the VSPP and provides the most immediately relevant data.
- Maryland and Washington, D.C. share a border with wealthier portions of Northern Virginia, which could be attractive markets for residential solar.

- Georgia and North Carolina have similar labor pools as right-to-work states and feature electric power industries that are similarly centered on large, vertically integrated investor-owned utilities.

These states also vary in the extent of both retail competition (only Maryland and Washington D.C. are fully deregulated) and wholesale market structure (only Georgia and non-Dominion-served portions of North Carolina are *not* part of the PJM regional transmission organization). However, the main reason for choosing these places is that they collectively represent a diverse range of development levels.

Figure 5 captures the variation in total installed solar PV capacity through H1 2015, with North Carolina over 1000 MWdc of solar deployed, Georgia and Maryland at similar intermediate levels, and Virginia and Washington D.C. with very low levels of solar to date. Furthermore, a consideration of detailed data from the GTM Research/SEIA Solar Market Insight reports reveals major variation across different market *segments*. Maryland is a clear leader in residential installed capacity; Maryland and North Carolina are co-leaders in the commercial sector; and North Carolina is the front-runner in the utility-scale sector (with Georgia showing some recent growth). The goal of studying such a diverse distribution is to investigate whether companies in states with greater experience in solar installations (as measured by installed capacity) have markedly different soft costs or business practices than their counterparts in states with less installed solar capacity.

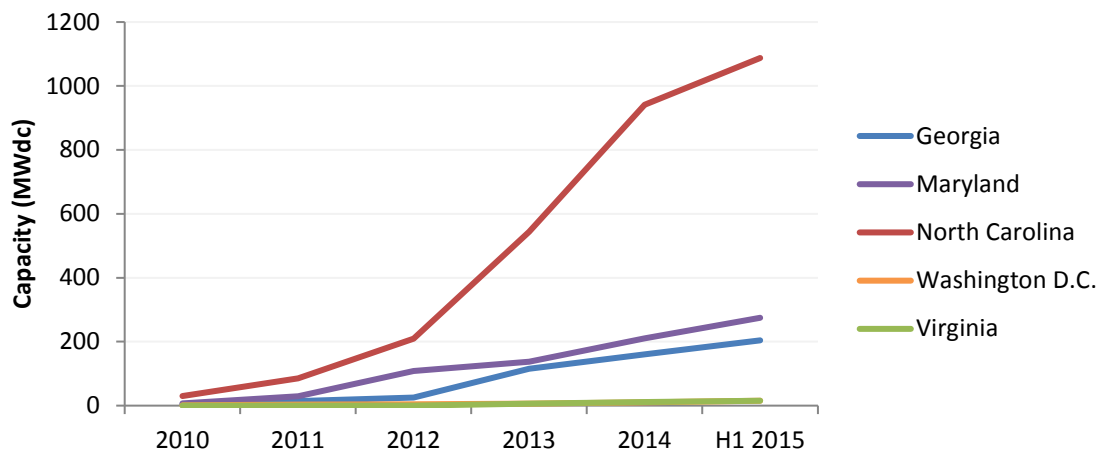


Figure 5. Cumulative installed solar PV capacity by state

Source: GTM Research/SEIA Solar Market Insight reports

A survey instrument to gather responses was developed using Qualtrics, a web-based survey site, and it was distributed to companies via email in October and November 2015. The initial distribution reached over 80 companies across the target states. Follow-up phone calls and emails were conducted to respond to all questions from respondents and to increase participation. The survey was closed on November 20, 2015. A copy of the web survey is included in Appendix B.

2.3.2 Utility Industry

The second aspect of the soft cost investigation in this report deals with the examination of soft costs and related utility-administered solar programs. Early in the development of this study, the

collection of data sufficient to generate reliable and direct cost estimates of utility soft costs (in \$/W) was identified as a major challenge due to:

- The relative scarcity of such programs, particularly in the residential sector
- The fact that many programs either are not active or were concluded several years ago, making their cost estimates less immediately relevant
- Utility concerns about confidentiality of operational data.

Instead, given the focus of the VSPP on developing “a collaborative utility-administered solar strategy,” the analysis of utility soft costs is structured around in-depth interviews with utility solar program administrators that examine how the utilities accomplished tasks in the various soft cost categories. A major point of emphasis in these profiles is a thorough documentation of the division of responsibilities in soft cost areas between utility staff and outside entities, such as installer partners or EPC contractors.

2.4 Results

2.4.1 Solar Industry

Of the over 80 companies that received the online soft cost survey, 20 provided some amount of information. From these responses, data on total soft costs were collected from nine companies and business practice information was collected from 10 companies. Summary statistics for installations of companies that provided soft cost information for the first half (H1) of 2015 are presented in Tables 1 and 2.

Table 1. Number of Installations Completed by Companies Providing Soft Cost Information (H1 2015)

	GA	MD	NC	VA	DC	Total
Residential	44	53	95	7	3	202
Commercial and Industrial (< 250 kW)	38	9	12	2	2	63
Commercial and Industrial (> 250 kW)	9	12	2	-	2	25
Utility-Scale	4	-	-	-	-	4
Total	51	21	14	2	4	294

Table 2. Capacity Installed (MWdc) by Companies Providing Soft Cost Information (H1 2015)

	GA	MD	NC	VA	DC	Total
Residential	0.2	0.5	0.6	0.3	0.2	1.7
Commercial and Industrial (< 250 kW)	4.7	0.4	0.6	0.1	0.8	6.6
Commercial and Industrial (> 250 kW)	8.5	12.5	3.1	-	1.0	25.1
Utility-Scale	3.0	-	-	-	-	3.0
Total	16.1	12.9	3.7	0.1	1.8	36.3

The survey responses represented anywhere from 3% (North Carolina) to 38% (Georgia) of the total solar PV capacity installed in each state during H1 2015. Across all states, the reported information covered 15% of the installed solar PV capacity during this period, which is in line with the representativeness of past NREL soft cost benchmarking reports (Ardani et al. 2012; Friedman et al. 2013). Given the small pool of responses, both in terms of numbers of companies and installed capacity, it is difficult to construct state-by-state comparisons of installer soft costs and business practices. Taken as a whole, however, they offer more recent and regionally focused insights than past national averages and future SunShot targets. The number of responses is documented throughout this report to indicate the sample size for each response category.

2.4.1.1 Total Costs and General Components

One of the first questions in the survey asked respondents to define the total \$/Wdc cost of an average system and then to specify, as a percentage, the share of costs attributable to four major cost categories: (1) modules, (2) inverters, (3) racking and other hardware, and (4) all soft costs. The summary of responses is shown in Figure 6, with each cost component shown in each market segment. The sum total of responses across segments is greater than the nine cost respondents because some companies participate in multiple market segments.

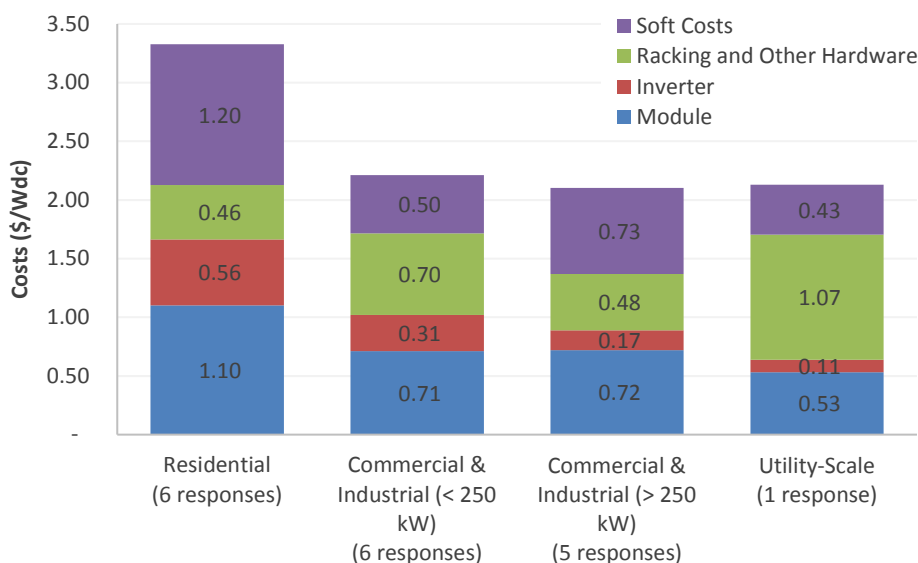


Figure 6. Surveyed categories of system cost by sector

Across all market segments, reported soft costs fall well below the levels from other recent sources; the residential and small commercial figures are roughly half of those modeled in the Q3 2015 GTM/SEIA Solar Market Insight report (GTM Research/SEIA 2015), which covers roughly the same timeframe as the survey. In the survey responses, module and inverter costs decrease with the size of system installed, which is to be expected as greater economies of scale can be achieved in procurement for these systems. The utility-scale figures are based on just a single response and should not be used as the basis for generalization. The portion of total costs attributable to soft costs is greatest in the residential sector (38%), as the amount of effort required in soft cost areas is spread across a smaller capacity per installation and activities such

as customer acquisition and financing become more critical. This share is 20% for small commercial, 34% for large commercial, and 20% for utility-scale installations.

2.4.1.2 Specific Soft Cost Components

Customer Activities: Customer Acquisition, System Design and Site Acquisition

Early questions in the installer soft cost survey asked respondents to report their total spending on customer acquisition, system design, and site acquisition in H1 2015. These total numbers were then allocated to each market segment of that installer, and all installer costs were averaged across the sample on a capacity-weighted basis as documented in Table 3. The number of respondents reporting these segmented costs was smaller than the number of respondents reporting overall installed cost and cost shares in the prior section.

Table 3. Customer and Site Acquisition Costs

	Residential	Commercial and Industrial (< 250 kW)	Commercial and Industrial (> 250 kW)	Utility-Scale
System design	\$0.01	\$0.01	\$0.06	--
Other customer acquisition	\$0.07	\$0.12	\$0.03	--
Total customer acquisition	\$0.08	\$0.14	\$0.09	--
Site acquisition	\$0.04	\$0.03	\$0.03	\$0.06
Respondents	3	4	3	1

Reported customer acquisition costs for the residential sector fall well below recently modeled levels (\$0.45/W in 2014), though costs for small and large commercial installations are in line with historically reported values (Shiao 2015). This discrepancy in residential costs may be driven in part by the large average system sizes for residential installers reporting customer acquisition costs (mean size is 15.1 kW). This system size is more than three times the 5 kW used in the most recent NREL benchmarking survey and the 6-kW system modeled in the GTM/SEIA Solar Market Insight reports. However, applying the reported total cost per customer from this survey to a 5-kW system size still yields a customer acquisition cost of only \$0.21/W, or roughly half of recent modeled values.

System design costs see a similar effect from the large average system size, yielding residential costs of \$0.01/W. In this survey, large commercial systems show a higher cost per watt, which runs counter to the expectation that economies of scale will reduce system design costs more than smaller installations.

On first comparison, site acquisition costs were relatively consistent across all market sectors, which is somewhat surprising given the potential for the economies of scale of larger systems to reduce cost per watt in the commercial and utility-scale sectors. However, this result was produced in part by just a single utility-scale response, making it difficult to generalize to the

broader market. Another issue is that residential site acquisition can be included in standardized lease or PPA agreements, making it difficult to track this cost in isolation. In general, this cost area is more of a consideration for utility-scale systems, where the process can include site screening and land lease or purchase negotiations.

Permitting, Inspection, and Interconnection

Respondents were surveyed on the estimated number of hours required for their companies to complete the various steps in the PII processes. To convert these labor totals into costs, we used the labor allocation and classification framework adopted in prior NREL soft cost survey efforts. These allocations and labor rates are shown in Table 4.

Table 4. Permitting, Inspection, and Interconnection Labor Allocation

Soft Cost Category	Occupation (Labor Class) ^a	Share of Labor Used (%)	Burdened Wage (\$/hr) ^b
Permit preparation	Permit procurement	70	42.14
	Administrative staff	30	19.21
Permit submission	Permit procurement	30	42.14
	Administrative staff	70	19.21
Inspection	Installer	70	17.35
	Administrative staff	30	19.21
Interconnection	Permit procurement	30	42.14
	Administrative staff	70	19.21
Incentive application	Installer	30	17.35
	Administrative staff	70	19.21

^a The business functions listed here correspond to the following occupations from the Bureau of Labor Statistics’ Occupational Employment Statistics:

- “permit procurement” — Business Operations Specialists, All Other
- “administrative staff” — Office and Administrative Support Occupations
- “installer” — Solar Photovoltaic Installers.

^b The burdened wages were calculated by averaging the median wage rate for each occupation across the five surveyed states. This average was then burdened according to the following rates from Friedman et al. 2013:

- Worker’s compensation insurance: 6.4%
- Federal and state unemployment insurance: 6.2%
- Social Security taxes (FICA), 7.65%
- Builder’s insurance: 0.44%
- Public liability insurance: 2.02%.

To further increase comparability to past results, we also adopted identical levels of overall permitting fees: \$430 for residential, \$5,000 for small commercial and \$25,000 for large

commercial systems. These fees were then calculated as a \$/W cost using our surveyed average system size as shown in Table 5.

Table 5. Permitting, Inspection, and Interconnection Costs

	Residential	Commercial and Industrial (< 250 kW)	Commercial and Industrial (> 250 kW)	Utility-Scale
Preparing a permit package	\$0.025	\$0.004	\$0.002	
Submitting a permit package	\$0.011	\$0.002	\$0.001	
Completing the permit inspection	\$0.008	\$0.001	\$0.001	
Completing the interconnection process	\$0.005	\$0.002	\$0.000	
Applying for and receiving incentives	\$0.005	\$0.001	\$0.000	
Total PII labor	\$0.054	\$0.010	\$0.005	
Permitting fee	\$0.040	\$0.049	\$0.026	
Total PII	\$0.094	\$0.059	\$0.031	
Respondents	3	4	4	0

As with survey responses for customer acquisition costs, survey responses for PII costs are well below values from recent benchmarking reports. However, given that this study’s average residential system size was much larger than those in the literature, the \$0.05/W PII labor cost for residential systems compares reasonably well to the \$0.10/W labor figure reported in Friedman et al. (2013). In the small and large commercial segments, current survey results align with prior surveyed values, as the economies of scale drive these PII costs for larger installations to an extremely low cost per watt. There were no responses to these questions in the utility-scale segment. The assumed permitting fees accounted for over 40% of residential and over 80% of commercial segment PII costs.

2.4.1.3 Adoption of Soft Cost Reduction Methods

The joint NREL/RMI publication, *Non-Hardware (“Soft”) Cost-Reduction Roadmap for Residential and Small Commercial Solar Photovoltaics, 2013-2020* identified a number of soft cost reduction strategies for the residential and commercial sectors and estimated their potential to assist in achieving the 2020 SunShot soft cost goals (Ardani et al. 2013). The survey conducted under the VSPP asked participants about their use of some of the specific soft cost reduction techniques outlined in the NREL/RMI report. Table 6 presents the uptake rates of specific alongside the estimated 2020 soft cost reduction potential of these practices (in 2010\$/W).

Table 6. Adoption of Soft Cost Reduction Strategies among Survey Respondents

Category	Cost-Reduction Opportunity	Residential		Commercial	
		2020 Cost Reduction (2010\$/W)	Adoption Rate	2020 Cost Reduction (2010\$/W)	Adoption Rate
Customer Acquisition	Direct mail		0%		11%
	Email		33%		56%
	Telephone		33%		56%
	Door-to-door		0%		0%
	Marketing partnerships	\$0.05	17%	\$0.01	22%
	Lead qualification and generation	\$0.07	33%	\$0.01	22%
	Referral program	\$0.12	100%		100%
	Customer awareness	\$0.14	50%	\$0.04	33%
Software	Remote site assessment	\$0.08	100%	\$0.01	100%
Design Templates	Standardized design templates	\$0.05	50%	\$0.02	56%
PII	Online database of permitting requirements by jurisdiction	\$0.02	60%		75%
	Online permit application submission	\$0.01	60%		75%
	Permitting fees < \$250/system	\$0.03	57%		
	Permitting fees < \$100/system		30%		
	Expedited interconnection process	\$0.01	73%		
Respondents			6		8

The survey responses indicate strong uptake of referral program and remote site assessment strategies across both residential and commercial sectors. Especially in the residential sector, these practices are viewed as potentially yielding large reductions in soft costs. However, both residential and commercial installers report relatively low engagement in customer education and awareness efforts, which offer potentially large soft cost reduction opportunities. Use of online systems for accessing permitting requirements and submitting documentation is moderate, though slightly higher among commercial installer respondents. Unlike customer acquisition techniques, which can be adopted unilaterally by a business, these permitting aspects require support from the local jurisdictions making their information and applications available via the web. In the residential segment, respondents indicated that just over half of installed systems see permitting fees below \$250, while nearly three-quarters of systems are eligible for expedited screening processes.

2.4.1.4 Other Practices

Financing

The survey also asked respondents to detail the share of projects completed in H1 2015 that were financed using specific methods. This list included third-party finance, secured and unsecured loans, and other means. A capacity-weighted average across the entire sample of responses is shown in Table 7. Over half of all capacity was delivered via direct cash purchases of solar systems by the new owner.

Table 7. Share of Projects Complete in H1 2015 by Financing Methods

Method	Share of Sample
Third-party ownership—lease	0%
Third-party ownership—PPA	22%
Secured loan via solar financier	0%
Secured loan via commercial bank	4%
Unsecured loan via solar financier	1%
Unsecured loan via commercial bank	0%
Property-Assessed Clean Energy loan	1%
Second mortgage	1%
Power Saver loan via FHA	0%
Direct Cash Purchase	57%
Other	14%

Beyond this general picture, there was a marked split in financing practices by different companies in different market segments. In Table 8, we compare the financing options of three companies that only deliver residential and small commercial installations with four that do strictly small and large commercial installations. The results reveal that combined residential/small commercial installers pursue a far wider array of financing avenues, and that small/large commercial developers appear to only be offering (or customers are only requesting) cash purchases and PPAs from third-party owners. We also note that the small and large commercial installers operate primarily in Maryland, where third-party owned PPAs are legal, while residential and small commercial installers work in the other three states, where third-party ownership is illegal (North Carolina), was legalized only after the survey period (Georgia), or is limited to facilities between 50 kW and 1 MW in size (Virginia) (“3rd Party” 2016).

Table 8. Financing Practices by Different Companies in Different Market Segments

Method	Residential and Small Commercial Installers	Small and Large Commercial Installers
Third-party ownership—lease	2%	0%
Third-party ownership—PPA	2%	30%
Secured loan via solar financier	0%	0%
Secured loan via commercial bank	0%	0%
Unsecured loan via solar financier	11%	0%
Unsecured loan via commercial bank	7%	0%
Property-Assessed Clean Energy loan	0%	2%
Second mortgage	18%	0%
Power Saver loan via FHA	0%	0%
Direct Cash Purchase	59%	68%
Other	0%	0%
Respondents	3	4

Operations and Maintenance and Insurance

Finally, the survey also asked respondents to provide information about areas of operational (rather than initial) soft costs, specifically the areas of O&M and insurance coverage. While these areas of soft costs have not been cataloged in the literature, it is useful to examine the prevalence of specific business practices in these areas. Table 9 shows the uptake rates of specific strategies among companies serving the residential and commercial sectors.

Table 9. Operations and Maintenance and Insurance Practices

Category	Business Practice	Residential	Commercial
O&M Practices	Real-time output monitoring	80%	88%
	Inverter replacement considered standard part of O&M	60%	63%
	Micro-inverters or other module-level power electronics	100%	75%
O&M Delivery	Contract with installer or EPC that built	40%	50%
	Deliver O&M in-house	100%	88%
	Outsource O&M to specialty provider	0%	13%
	Other	0%	0%
Insurance	General liability insurance	80%	88%
	Property risk insurance	40%	63%

Category	Business Practice	Residential	Commercial
	Professional liability insurance	40%	63%
	Inland marine insurance	40%	38%
	Business interruption insurance	40%	25%
	Environmental risk insurance	0%	25%
	Workers' compensation insurance	80%	75%
	Warranty insurance	20%	25%
	Contractor bonding	40%	50%
	Other	0%	0%
Respondents		5	8

In the area of O&M, we find that all residential installers and many commercial installers use microinverters or other module-level power electronics, though we do not track the share of installations (by count or by capacity) for which they were used. Still, this familiarity level appears to be higher than the national average, where microinverters were used for roughly 30% of the residential solar capacity installed in the United States in Q1 2015 (Shiao 2015). These technologies can support maintenance practices by offering module-level energy production data and monitoring. Real-time output monitoring is also offered by nearly all installers in the residential and commercial sectors. This practice is advantageous for the quick identification and resolution of performance issues. However, a much lower percentage of installers consider the replacement of inverters as a regular O&M expense. Accounting for inverter replacement has been recommended as an industry best practice due to the mismatch in operational life of PV modules (typically 20+ years) and inverters (commonly 10 years) (Keating, Walker, and Ardani 2015).

In the field of O&M delivery, nearly all installers offer O&M services themselves. In cases where the respondent acted as a developer and contracted out the installation of a system, it may have chosen to contract for O&M services from the same firm that completed the installation. Only one commercial developer reported using a specialty O&M firm to deliver these services.

In the area of insurance, the two most commonly held policies are general liability insurance, which protects against claims of negligence, and workers' compensation insurance, which provides funds in the event of workplace injuries. It is interesting to note that there was wide variation in the types of coverage held by respondents; that is, the responses were not driven by a few companies holding every type of coverage possible but rather many companies holding a few coverages of varying types. In the commercial sector, the next most popular coverages were for property risk and professional liability. Warranty insurance was rarely held by either residential or commercial installers.

2.4.2 Utility Industry

Having developed regional data about existing soft cost levels and strategies, we next sought to understand the potential for utility involvement to reduce soft costs of solar installations. To demonstrate the numerous possible program structures, profiles of utility-administered solar

programs are provided in Appendix A. To specifically examine business practices in the areas of soft costs, interviews were conducted with three utility companies across the residential, commercial, and utility-scale solar market segments. One key goal of these interviews was to understand the division of responsibilities between the utility and other parties, be they rooftop installers or utility-scale EPC companies. It is critical to understand the responsibilities of each entity as the programs were likely designed to best leverage each party’s core business strengths. The following case studies reveal the division of responsibilities and define reasons for these structures, where possible.

2.4.2.1 Residential: Tucson Electric Power

Tucson Electric Power (TEP) is one of only a few utilities in the country to offer a utility-owned rooftop solar program for residential customers. Established following an Arizona Corporation Commission ruling in late 2014, TEP’s program is capped by the Commission at 600 participants and by TEP’s program budget \$10 million of total cost; the program will be bound by whichever limit is reached first. In return for allowing TEP to install systems on their roofs, participating customers receive what is essentially a fixed monthly bill, allowing them to pay the same amount each month over the 25-year duration of the program, so long as their annual energy usage remains within $\pm 15\%$ of their baseline annual usage.

One of the key aspects of TEP’s program is its partnership with solar installers to deliver systems to customers. TEP initiated this partnership through a request for proposals (RFP) to solar installers and ultimately selected three companies to construct rooftop PV systems under the program. The selected companies in turn agreed to deliver the installed systems to TEP at a flat \$/W cost across their portfolio of assigned projects. However, the responsibilities of the installer go well beyond simply constructing the solar systems. Table 10 highlights roles played by each party in specific soft cost areas of interest.

Table 10. Division of Responsibilities for Tucson Electric Power Residential Solar Program

Soft Cost Area	Tucson Electric Power	Installer Partners
Customer Acquisition	Lead generation via press releases, newsletter, and website Lead prequalification based on TEP bill payment history, minimum system size, and owner-occupied residence Frequently asked questions on website explaining program and fixed bill value proposition	Engage prequalified TEP customers, explain TEP program, conduct site visits, assess suitability, address access and HOA issues, finalize and close contract with customer
System Design	Provide design guidelines for minimum and maximum system sizes, preferred orientation, tilt, modules and inverter	Finalize individualized home design
Permitting	Initial outreach to jurisdictions on utility-side-of-meter interconnections	Prepares and submits all permits to local jurisdictions
Interconnection	Interconnection agreement does not exist in traditional sense (TEP asset connecting to TEP system)	
Inspection	Review and accept as-built systems	Requests and schedules with TEP

Soft Cost Area	Tucson Electric Power	Installer Partners
Incentives	Handled via internal accounting	--
Financing	All systems owned by TEP	--
Supply Chain	Bulk procurement of modules and inverters for program, stored in existing TEP warehouses/facilities	Provide racking, wiring and all other balance of system components
O&M	Hourly production monitoring through existing TEP communications system; Plans to deliver long-term O&M	Responsible for delivering O&M services for first 10 years via warranty
Insurance	Covered by TEP self-insurance	--

Customer Acquisition

TEP characterizes its role in the customer acquisition phase of a rooftop solar installation as essentially lead generation and screening. In 2015, using press releases, its corporate website, and a newsletter with roughly 80,000 subscribers, TEP created an “interest list” of customers who were actively considering participating in the rooftop solar program; the list grew to over 5,000 customers through the course of the year. Because interest greatly outpaced the available slots in the program, TEP opened enrollment periods in which applicants could request to participate in the rooftop program on a first-come, first-serve basis. The first two enrollment periods, each of which sought to bring in 200 customers to the program, were fully subscribed in a matter of minutes.

Applicants to the program were then screened by TEP on several factors, including payment history on TEP bills, a minimum electricity consumption threshold of 6,700 kWh/year (which corresponds to the minimum PV system size of roughly 3 kW), and accountholder ownership of the property where the solar system would be installed. Once this evaluation process is complete, TEP assigns each pre-qualified lead to one of the three installer partners and distributes lead assignments so that the average system size of each installer’s portfolio is roughly equal. The assigned installer partner then undertakes many of the individualized aspects of customer acquisition, including remote site assessment, customized system design, site and customer visits, explanation of TEP’s fixed bill compensation mechanism, and signing of the official contract.

System Design

As with customer acquisition, system design is an area in which TEP provides general support and the installer partners deliver customer-specific solutions. TEP provides a number of guidelines to installer partners when it comes to system design, including:

- Minimum and maximum system sizes: from 3 kW up to 85% of the required system size to entirely “net out” customer consumption
- Orientation and tilt: 150° to 270° orientation (SSE to W); 10° to 30° tilt

- Specified modules and inverters: REC modules, Fronius inverters.³

These guidelines ensure the installed systems accomplish some of the major aims of TEP's program. For example, TEP emphasizes southwest- and west-facing arrays due to the better match between solar generation and system demand.

The design of TEP's program also creates more options in terms of installer design choices. Unlike a traditional net-metering arrangement, in which the size of a solar array directly affects the value of the consumer's bill credits, the energy delivered to TEP by a specific is totally decoupled from the value of the fixed bill compensation mechanism to that system's host. This creates an environment in which TEP's installer partners are strongly incentivized to build the lowest-cost system that conforms to TEP guidelines rather than attempt to maximize annual energy production and customer bill credits. This incentive structure allows the installer partners to avoid potentially costly designs, such as systems with several non-contiguous racking and panel sections arranged across multiple roof surfaces. It also eliminates the distinct preference for south-facing systems that produce the most energy and hence the most bill credits for customer- or third-party-owned systems. Instead, it increases the number of solar-viable rooftops by accepting more westerly-facing rooftops that may produce fewer but more-valuable kilowatt-hours. Reducing frequency of more costly designs and increasing the pool of addressable rooftops can decrease the average installed cost of an installer's (and hence TEP's) portfolio of projects.

Permitting, Inspection, and Interconnection

Responsibility for preparing and submitting permit application to local jurisdictions falls to the installer partners, as they have developed the system designs for each customer system. However, TEP initially played an important role in this aspect of project development by meeting with multiple local permitting agencies to discuss the unique design of the utility-owned rooftop systems. In TEP's service territory, all rooftop solar systems, whether owned by the customer, TEP, or a third party, have a production meter through which all energy produced by the solar array passes. However, the system designs differ beyond this point; energy from customer or third-party systems is then fed to the customer's load center and, if necessary, the customer's bi-directional consumption meter (at which it is net metered), whereas energy from TEP-owned systems is delivered directly to the utility side of the customer meter, completely bypassing customer loads. Education and outreach by TEP was vital to prepare local permitting offices for this new method of system interconnection design. Installers are responsible for scheduling inspections by the local jurisdiction once the system is completed.

Systems designed under this program must meet a variety of technical standards as specified in the system design criteria and are TEP generation assets connecting to a TEP distribution system. Therefore, the installer partners are not required to prepare interconnection applications in the same fashion as other customer-sited solar PV systems. Inspections by the utility constitute the review and acceptance of the as-built system as a generating asset, not simply a check for compliance with interconnection procedures.

³ REC is a solar business headquartered in Norway.

Incentives and Financing

All systems installed under TEP's residential rooftop program are fully owned by the company and are added to the company's rate base. These systems are also eligible to receive the federal ITC, which amounts to 30% of the installed cost of a solar energy system. The tax credits generated by these assets are subject to tax normalization rules, as described in Section 4. The value of each system is calculated based on the fixed \$/W price of installation provided by the specific installer partner in addition to the value of the TEP-procured modules and inverters used in the installation. Most of the value of these systems is treated as generation assets, though some portion of the costs may be counted as distribution or transmission assets according to Federal Energy Regulatory Commission (FERC) Form 1 data.

Supply Chain

Due to the large program size and a desire to standardize the componentry and design of systems as much as possible, TEP procured both the PV modules and the inverters to be used in the rooftop solar installations. In total, TEP acquired 3 MW of REC Solar modules⁴ and Fronius inverters in four sizes to meet the needs of multiple sizes of installation. While this purchase size is not large when compared to the amount of hardware needed for utility-scale projects, it is on the larger end of volume for residential installers in the Tucson area. TEP was able to easily accommodate this inventory in existing TEP storage facilities and did not require building or acquiring additional space.

Operations and Maintenance

TEP will be able to monitor output from its systems on a regular basis using the production meters installed with each system, which provide hourly granularity for TEP to generate fleet production curves. These data are transmitted daily, enabling quick detection of issues and requests for service from installer partners. With installations covered by a 10-year installer warranty, TEP plans to rely on its installer partners to perform maintenance as needed for the initial phase of the program. After that period concludes, TEP plans to perform O&M activities itself by leveraging expertise gained from its own fleet of utility-scale solar installations, for which it delivers O&M services both in-house and through third parties.

Insurance

As with most utility assets, the rooftop systems installed by TEP are covered through corporate self-insurance. TEP did not have to take any incremental actions to accomplish this expansion of coverage to rooftop systems. The interaction with customer property and premises also did not pose an issue, as TEP already have the need to access or service physical assets, such as meters, that lie on customers' properties.

2.4.2.2 Commercial and Utility-Scale: National Grid

National Grid began its involvement in solar project development following the passage of Massachusetts' Green Communities Act in 2008, which officially sanctioned utility ownership of

⁴ REC Solar is a solar business headquartered in the United States.

solar systems.⁵ Since that time, National Grid has run two distinct programs for utility-owned solar facilities. Phase I, begun in 2009, was targeted at boosting the visibility and development of the commonwealth’s solar industry, which was then still in its infancy. Phase II, launched in 2014, sought to explore the technical and operational potential of advanced inverters, other distribution-connected technologies and strategic locational solar deployment prior to their greater general adoption (and in advance of the sunset of the Green Communities Act). These two separate programs offer insights into utility business models for solar deployment at different phases of state-level market development; installed capacity in the state rose more than tenfold in between the two programs. The differences in program design and execution (Table 11) may offer insights for a broad set of states at various points in the evolution of their solar markets.

Table 11. Division of Responsibilities for National Grid Solar Programs

Soft Cost Area	Phase I		Phase II	
	National Grid	Developers	National Grid	Developers
Customer Acquisition	N/A	--	N/A	--
System Design	Provided example designs (50% set, layout)	Finalized system designs	--	Entirely responsible for system design
Site Acquisition	Selected National Grid-owned sites with past remediation work	--	Shortlisted 10 sites for development	Selected sites from provided list of targeted towns, secured lease agreements with landowners
Permitting	Submitted layout to local AHJ	Receives completed permit from National Grid	--	Entirely responsible for preparation and submission
Interconnection	Prepared and submitted standard interconnection applications	--	--	Prepared and submitted standard interconnection applications
Inspection	Identical scheduling and review process as for outside projects	--	Identical scheduling and review process as outside projects	--
Incentives	Handled through internal accounting	--	Handled through internal accounting	--

⁵ Without this act, National Grid is unable to own or operate major generating assets under the terms of electric industry restructuring in Massachusetts.

Soft Cost Area	Phase I		Phase II	
	National Grid	Developers	National Grid	Developers
Supply Chain	Procured modules and inverters for program's first project	Procured modules and inverters for other projects	Supplied technical standards for advanced inverters	Procured modules and inverters for projects
Financing	Systems rate-based as with other capital assets, energy and solar renewable energy certificate (SREC) revenues pay down cost of asset	--	Systems rate-based as with other capital assets, energy and SREC revenues pay down cost of asset	--
O&M	Contracted out general site O&M, systems covered under five-year warranty	--	Contracted out general site O&M, systems covered under five-year warranty	--
Insurance	Self-insured, may be required to hold decommissioning bond	--	Self-insured, may be required to hold decommissioning bond	--

System Design

As Phase I of National Grid's solar program sought to demonstrate viability of solar in Massachusetts' fledgling market, National Grid was heavily involved in the solar system design, providing general system designs and layouts to developers, who then developed detailed plans to capture details such as module stringing and wiring. By the beginning of Phase II, however, the Massachusetts market was sufficiently developed that National Grid was able to rely on its developer partners for all aspects of system design.

Site Acquisition

A major feature of the Phase I projects was that four solar facilities were developed on National Grid-owned land parcels that had previously hosted manufactured gas plants, which had led to restricted use of the sites. National Grid's prior ownership meant no additional contracting arrangements were necessary; further, all environmental remediation work was completed prior to the installation of the solar sites. In Phase II of the solar program, National Grid created a short-list of sites for developers to propose projects. The proposals accepted by National Grid were also screened for potential electrical benefits based on the size of the proposed system and location on the nearby feeder. It was the responsibility of the developer to identify host sites

willing to participate in the program, though ultimately the land or roof space was leased for 20 years directly to National Grid rather than by the developer.

Permitting, Inspection, and Interconnection

Permitting and interconnection application submittal are both aspects of project development that were the responsibility of National Grid in Phase I but that transitioned to the developer partners in Phase II. For interconnection, National Grid made it clear that all solar systems in Phases I and II were subject to an identical application, screening and study process as any other developer-initiated project in order to avoid any actual or perceived preferential treatment. Given the relatively large system sizes under the program, almost all facilities were subject to supplemental review or full impact studies. The inspection process was executed with similar impartiality to the interconnection process.

Incentives and Financing

As a distribution utility in a restructured market, National Grid is typically precluded from owning any generation assets. As a result, it was impossible to compare its ownership structure to those of other generating assets, but National Grid staff did indicate they are treated just as any other capital asset through the company's rate base. The value of the ITC for these solar systems is subject to normalization just as for any other utility asset, with the value of the tax credits used to reduce the cost of the asset over time. Any other revenue streams, such as from ISO-NE's wholesale energy market and the state's SREC market, are also used to pay down the cost of the system. National Grid expects that once the assets are paid off through a combination of rates and external revenues, any additional revenues will become a credit to ratepayers.

Supply Chain

For the first of the Phase I projects, National Grid was responsible for procuring the modules and inverters necessary to construct the system. However, procurement for the majority of projects in Phase I fell to the selected developers. The developers were also entirely responsible for procuring all hardware in Phase II, though National Grid played a role in selecting inverters. As the goal of Phase II was to explore the operational benefits of distributed solar with advanced inverters, National Grid supplied technical specifications to the developers to ensure the installed inverters would be compatible with this purpose.

Operations and Maintenance

Operations and maintenance services for basic facility upkeep (e.g., vegetation and fencing) are subcontracted to a third party. For the PV systems themselves, National Grid is still able to rely on the five-year workmanship warranties of their developer partners for both Phase I and Phase II projects. However, with the end of these warranties approaching for Phase I projects, National Grid is investigating whether to contract out ongoing facility O&M through a RFP or take over the provision of these needs through an internal group. National Grid has pegged its cost estimates for O&M at \$20/kW-year based on a 2013 NREL analysis ("Distributed Generation" 2013).

Insurance

As with other large utilities, National Grid is able to cover its solar facilities through its own self-insurance policy. One related issue is that of decommissioning, as towns where solar facilities are constructed may require developers to put up money for a bond to address the disposal or removal of a system at the end of its useful life. Towns often see this as necessary due to the potential for developers to go out of business during the decades-long operational life of the project and the compartmentalized financial structures created to own projects, such as single-project limited liability companies (LLCs). National Grid suggests it may have an advantage in this area as a larger, more financially stable business.

2.4.2.3 Utility-Scale: Kauai Island Utility Cooperative

Since 2011, the Kauai Island Utility Cooperative (KIUC) has developed two 12-MWac utility-scale solar PV facilities on the island of Kauai, which collectively are expected to supply 11% of the island’s electricity sales. The two facilities have been developed under EPC contracts with separate companies, with REC Solar⁶ performing work on the Anahola array at a cost of \$38 million and SolarCity developing the Koloa project at a cost of \$35 million. These total project costs equate to per-watt values of \$2.62/Wdc and \$2.45/Wdc respectively for the two solar systems. In addition, the two large arrays feature battery storage systems, with Anahola having 6 MW of storage and Koloa having a 2-MW system; the costs of these storage systems are not included in the installed costs above. Given the small jurisdiction in which KIUC operates, it was more heavily involved in the development process than may be typical of an EPC contract. Additionally, KIUC’s status as a non-profit cooperative affected the financial structure of the projects, which in turn impacted the insurance coverage of the assets. The division of responsibilities between the EPC companies and KIUC across several relevant soft cost categories is shown in Table 12.

Table 12. Division of Responsibilities for Kauai Island Utility Cooperative Solar Program

Soft Cost Area	KIUC	EPC Companies
Customer Acquisition	N/A	N/A
System Design	Support design process by providing information on interconnecting facilities	Lead general and detailed design process
Site Acquisition	Identified sites, negotiated and signed lease agreements	--
Permitting	Leverages relationships in small jurisdiction to pre-screen potential issues	Prepares and submits all permits to local jurisdictions
Interconnection	Designs and constructs physical interconnection facilities	Prepares system documentation necessary to arrange interconnection
Inspection	Inspects facilities and site	--
Incentives	Handled through internal accounting	--

⁶ In this report both REC and REC Solar is mentioned. REC is a solar business headquartered in Norway, and REC Solar is a solar business headquartered in the United States.

Soft Cost Area	KIUC	EPC Companies
Financing	Structured facility-specific entities and pursued specific financing opportunities	--
Supply Chain	Supplied specifications and guidance	Procured all equipment for construction of solar arrays
O&M	Delivers services in-house	--
Insurance	Facilities must be covered outside of co-op insurance due to legal status as separate entities	--

System Design

The EPC companies were responsible for general and detailed system designs. KIUC was able to provide guidance on specifications for the facilities, particularly in terms of the controls and communications capabilities needed to manage large variable energy resources on a relatively small local electric system. Also, the inclusion of battery energy storage systems in both facilities made them easier to integrate into grid operations.

Site Acquisition

The Anahola array is situated on a 55-acre parcel leased to KIUC by the State of Hawaii's Department of Hawaiian Home Lands, while the Koloa array is on a 40-acre site on a 67-acre parcel leased from the Grove Farm Co., Inc. near Koloa. For both sites, KIUC negotiated and signed the leases without involvement from the EPC companies.

Permitting, Inspection, and Interconnection

Having developed the system designs, the EPC companies were also responsible for preparing and submitting the required permitting documents to local jurisdictions. However, KIUC played a key role in facilitating conversations with the local permitting jurisdiction. Given the small size of the local jurisdiction and the large scale of the two projects, KIUC's local relationships created an atmosphere in which concerns could be raised and addressed prior to the final submission of the permitting package. For interconnection of the systems to the local grid, the EPCs prepared interconnection request and agreement documentation, with KIUC managing the construction of the interconnecting facilities. Inspections by the local jurisdictions and KIUC were conducted as with any other interconnecting system.

Incentives and Financing

All incentive applications and financial aspects of the projects were handled internally by KIUC with no involvement from the EPC partners. The projects were developed under two distinctly different financial models; the Anahola project used a Section 1603 grant from the U.S. Treasury to cover 30% of the system cost, and the Koloa project used a tax equity flip structure to capture the 30% federal ITC. To effectively monetize these incentives, each solar project is held by a stand-alone for-profit LLC. These financial strategies were necessary because KIUC, as a not-

for-profit customer-owned collective, has a very different tax liability and accounting structure than many other entities. Financing for portions of project cost not covered by the applicable incentives was obtained through the National Rural Utilities Cooperative Finance Corporation (CFC) and its affiliate, the National Cooperative Services Corporation (NCSC). The CFC provided a three-year non-revolving line of credit to finance construction of the Anahola project, up to a total project cost of \$70 million. Separately, NCSC provided a loan of up to \$41.6 million to finance the Koloa system, with construction financing in the amount of \$16.5 million at interest rates of 2.649% to 2.665% through 2014 and permanent financing for the remainder of costs at a 4.65% interest rate (“Report of Independent Auditors” 2015).

Operations and Maintenance

After considering several proposals from companies to deliver O&M services on these arrays, KIUC chose to deliver these services internally. The co-op was able to tap into organizational experience in delivering O&M services to other KIUC-owned generation assets throughout the island. By KIUC’s own assessment, providing O&M services for a solar array is far less complicated than servicing their other generating assets such as fuel-oil-fired power plants, encompassing far fewer moving parts and a lower level of risk.

Insurance

One consequence of the special arrangements to finance and fully monetize potential incentives was their impact on the insurance strategy to cover the solar assets. With ownership of the projects residing with the LLCs rather than with KIUC, the solar systems could not be insured under the same policies which cover KIUC’s other physical assets. Instead, these assets had to be covered by commercially-purchased property insurance policies.

2.5 Discussion

Through an examination of historical data on soft costs in the solar industry, recent results of our regional survey, utility solar program designs and utility practices in soft cost areas, we identify several soft cost areas that show the greatest potential to be impacted by a utility-administered solar program. It is important to note that the attractiveness of such programs or partnerships—to either solar industry participants or electric utilities—may vary based on a variety of factors, such as solar industry business models and levels of development, the local regulatory environment, and local economic development goals.

2.5.1 Potential Areas for Solar Industry-Utility Interaction

In large part, the attractiveness of the following collaborations depends on the business goals of the local solar development community. Some solar installers are strictly focused on core competencies of solar system design and construction, essentially acting as solar construction companies and focusing on the sale of solar PV systems to customers. Other companies are interested in owning solar assets, maintaining ongoing customer relationships, and becoming energy service providers; in essence, these companies are in the business of selling solar energy rather than solar systems. This contrast is clearly embodied in a single company, SolarCity, which in 2015 began to describe its business as being comprised of two distinct functions: a development company (DevCo), which is focused on identifying customers and installing solar PV, and a power company (PowerCo), which finances these physical assets and engages in

energy generation, asset management, and customer billing functions (“Q1 2015 Earnings” 2015). Installers that resemble a strict DevCo may seek one type of partnership, while a combined DevCo/PowerCo might favor others. The following commentary notes areas where installer business models could impact prospects for collaboration.

2.5.1.1 Customer and Site Acquisition

Customer acquisition has long been a major component of soft costs in the residential solar industry, ranging between 14% and 20% of total soft costs for residential systems across historical NREL and GTM Research estimates (Ardani 2013; Shiao 2015). In real terms, this category of soft costs must decline more than 70% from recent estimates in order to achieve 2020 SunShot goals. While the VSPP survey results indicate customer acquisition costs well below recent estimates (and even below SunShot 2020 targets), this result is driven in part by the sample’s average system size being 150% to 200% greater than the modeled systems in recent assessments. Further, the small respondent pool for residential installers makes wide variation in pricing estimates more likely.

Instead of focusing on surveyed costs, it may be more useful to examine the business practices being employed by surveyed installer companies in this field. While survey responses indicate that all companies are leveraging referral programs in their activities (a practice estimated in Ardani et al. [2013] to enable a \$0.12/W cost reduction by 2020), fewer than half of respondents are using customer awareness programs, lead generation and qualification, or marketing partnerships, which in total are estimated to yield an additional cost reduction of \$0.26/W.

Demand for improved customer acquisition practices is echoed in the results from EnergySage’s 2015 solar installer survey (“Solar Installer Survey” 2015). Among other details, the survey revealed:

- Forty-two percent of installers rated their potential customers’ lack of familiarity with solar as a top challenge in closing sales, placing it second to price competition from other companies (44%).
- Access to better quality leads was ranked as the #2 competitive need, with access to more leads coming in at #5.
- The top three strategies to meet firm-level three-year objectives all revolve around customer acquisition: leverage new marketing and sales channels (e.g., online sales channels, partnerships); increase marketing and advertising to generate more leads; and improve the efficiency of the sales process.

Notably, the areas of customer acquisition that were underutilized in VSPP survey results but highly sought-after in the EnergySage installer survey—customer awareness, lead generation and qualification, and marketing partnerships—are services that electric utilities may be equipped to deliver at low cost. Utilities are constantly conducting customer awareness campaigns on topics as varied as safe excavation practices, energy efficiency measures, and the hazards of power outages, and they could easily leverage existing communication channels (e.g., websites and bill inserts) to engage potential solar customers. Furthermore, TEP’s experience in selecting customers for its rooftop solar program clearly demonstrates how utilities can serve as lead generators and qualifiers, leveraging a large customer base, pre-existing relationships, and varied

communication channels to generate customer interest before screening on certain criteria and passing leads to installer partners. Georgia Power's recently launched solar consulting service (described in Appendix A) is structured to serve much the same function. Finally, utilities and installers could engage in marketing partnerships, such as those allowing solar installers to place information in customer bills in return for a per-customer referral fee, some share of renewable energy certificates (RECs) generated, or other financial compensation.

Among commercial sector respondents, we note even lower uptake of customer awareness programs, lead generation and qualification, or marketing partnerships than in the residential sector. Though the potential savings in terms of \$/W of installed cost are somewhat lower, they could still contribute to reduce soft costs to meet 2020 SunShot targets. Utilities may be well equipped to support this type of engagement with commercial customers due to more direct contact with key commercial and industrial account holders. In addition, in situations where rooftop lease agreements are negotiated with large real estate holding companies or financial institutions, utilities may be seen as a reliable counterparty.

Site acquisition is often included in the terms of residential contractual agreements and is therefore intimately connected with the customer acquisition process. In the commercial sector, where site selection and acquisition can be a distinct step, utilities are well equipped to identify sites that will not require long interconnection lead times or costly infrastructure upgrades due to their ready access to operational data for the local distribution system. This issue is less of a concern in the residential sector due to smaller system sizes, but it can be critical for systems approaching megawatt-scale. A few states, notably California⁷ and Hawaii,⁸ have begun to require utilities to make such PV hosting capacity information publicly available to installers. In these states, this will reduce the utility's informational advantage in identifying electrically low-impact sites for PV, but collaboration on site selection may still be desirable in other regions. For larger commercial and utility-scale systems, utilities may be valuable partners in securing site access through lease agreements with hosts, as demonstrated by KIUC's project development experiences, or by providing access to utility-owned sites, as with National Grid's Phase I program.

Differences in solar firm business models are unlikely to dramatically affect the willingness to partner with utilities on customer acquisition, so long as the interaction is strictly limited to the business process at hand. Both DevCos and DevCo/PowerCos can benefit from increases in deal volume, so long as the cost per customer is below their current acquisition spending. The only potential business model effect could be the DevCo/PowerCo's emphasis on long-term customer relationships, which could make them more hesitant to cede any aspect of control over the customer acquisition process.

⁷ Each of the three largest investor-owned utilities (IOUs) in the state has made some information from its Integration Capacity Analysis public in accordance with the Distribution Resources Plan proceeding. For more information, see <http://www.cpuc.ca.gov/General.aspx?id=5071>

⁸ Each of the HECO companies allows customers to determine the PV penetration level on the feeder serving their address. For more information, see <http://www.hawaiianelectric.com/heco/Clean-Energy/Integration-Tools-and-Resources/Locational-Value-Maps>

2.5.1.2 Insurance

Insurance of solar assets is a small but ongoing soft cost over the life of the solar asset. While solar system owners may need to acquire coverage from insurance providers at market rates, utility companies can self-insure such assets at no additional cost due to their large financial size. In addition, the financial stability of larger electric utilities can eliminate the need to obtain warranty insurance to cover claims associated with performance guarantees. This can be a small but additional cost saving realized under utility ownership models.

2.5.2 Other Soft Cost Areas

While the areas above are the most obvious candidates for further investigation of industry-utility interaction, it is also helpful to understand what areas of business practices and soft costs are less likely to benefit from such engagement. These areas include:

- **Installation:** One of the largest soft cost components, installation labor is a core competency of the solar industry and is not typically a developed capability for electric utilities. Appendix A shows that whether for cost savings, risk management, or other reasons, outside solar installers (or the utility's unregulated development arm) were used to construct solar PV systems in all residential programs and almost all commercial programs.
- **System design:** Like installation, this is a well-developed industry capability that is often not readily available within electric utilities in the residential and commercial sectors. However, certain utilities may possess experience and capabilities equivalent to the solar industry in the utility-scale sector.
- **Permitting, inspection, and interconnection:** In the permitting component of this category, soft cost advantages are likely to be low, as the solar industry and utilities will face the same requirements from local permitting authorities. In addition, both will be familiar with the jurisdictions requirements. For interconnection, cost reductions could arise if the utility has a different process for utility-owned solar assets (as TEP does) rather than precisely mimicking the solar industry process (as National Grid has). However, solar industry participants in surveyed areas reported using expedited interconnection processes for 73% of all residential projects, so this may cap the ability of new coordination methods to improve on the status quo. Finally, PII is far smaller than customer acquisition or financing, so consideration must be given to whether any potential cost savings are sufficient to justify the transaction costs of setting up a partnership in this area.

Other areas with mixed or uncertain potential for utility engagement include:

- **Financing:** One of the most-discussed topics in utility-administered solar programs has been whether utilities should be allowed to own and rate-base residential customer-sited solar. Ultimately, the decision on the appropriate role of utilities in the competitive solar market must be determined by the relevant regulatory authority in each state.

Several factors encourage further consideration of solar industry-utility collaborations on financing. First, "access to more financing options" was the number one competitive need listed by solar installers in EnergySage's 2015 survey ("Solar Installer Survey" 2015).

Second, utilities have been shown to be capable of playing a role in financing, such as under the Solar Loan program offered by PSE&G in New Jersey. Finally, certain states in the Southeast—Alabama, Florida, North Carolina, and South Carolina—prohibit third parties from offering solar PPAs, while others (e.g., Virginia) limit the availability of PPAs based on system size (“3rd Party” 2016). Such regulations limit customer access to financing options from non-utility entities but allow utility financing or ownership of solar assets.

The utility-administered solar programs listed in Appendix A capture the variety of financing and ownership arrangements employed by the utilities. In the residential sector, Georgia Power’s program is the only one that offers no financial intermediation; it instead requires participants to purchase the solar system outright (or to independently arrange financing). In the other cases, ownership is retained by the utility (Arizona Public Service [APS], TEP), utility subsidiary (“ConEdison Solutions” 2015), or contracted installer (PowerFin Partners for CPS Energy). In the commercial space, utilities retained ownership of the solar assets in all programs that were considered. Finally, utility-scale assets under the models presented place ownership of the solar asset with the utility or utility subsidiary.

However, the ultimate determinant of whether utility involvement in financing can lower soft costs comes down to the cost of capital for utilities, solar customers (via solar loans), and third-party solar owners. The weighted average cost of capital (WACC) is equivalent to the average rate of return that a firm expects to compensate its investors and is based on the mix of debt and equity in the firm’s capital structure. Based on data from the Edison Electric Institute, the average awarded return on equity across all rate cases in H1 2015 was roughly 10%, while 90% of utilities had credit ratings between BBB and A (“Rate Case Summary” 2015; “Q4 2015 Credit Ratings” 2015). The average yield on bonds in these two rating categories over this period was roughly 3.2% (BofA 2016a; BofA 2016b). Combining this information with a capital structure of 50-50 debt-equity, we find that utilities in H1 2015 had a weighted average cost of capital of roughly 6%. By comparison, a 2014 NREL survey of the solar loan market found that residential customers could secure solar loans at an interest rate between 3% and 9%, depending on credit and the type of loan offered (Feldman and Lowder 2014). WACC for third-party solar owners is more difficult to determine; estimates of the WACC for SolarCity range from 6% to 9% or higher (Lutton 2014; Adebajo 2014; Horowitz and Graves 2014).

Moreover, WACC alone does not tell the entire story of financing considerations. Normalization accounting rules may restrict the ability of utilities to realize value from tax credits or depreciation, increasing the cost of solar energy to customers unless the utility pursues alternative cost recovery or revenue models; this issue is explored in detail in Section 4. One result presented in that section indicates that a utility subject to tax normalization would need to have a 4.8% WACC in order to deliver solar energy at the same price as a non-normalized entity having an 8.5% WACC. Similarly, customers owning their own system and pursuing solar cash purchases or solar loans will need to have significant tax appetite to fully take advantage of these tax benefits themselves. Finally, the tax status of municipal utilities and electric cooperatives can complicate

financing and incentive capture. For example, KIUC was ineligible to receive the benefits of the ITC due to its tax-exempt status as a cooperative. Therefore, it was forced to create individual for-profit subsidiaries for each project to capture this value stream.

Unlike customer acquisition, differences between DevCos and DevCo/PowerCos will significantly impact their willingness to work with utilities to finance projects. DevCos, which are strictly in the business of building and selling projects, would be more likely to see value in a utility partnership, especially if offered a contract to build a portfolio of solar installations (as in TEP's residential solar program), rather than the one-off projects they currently produce. So long as these businesses can sell solar PV systems, it matters little whether the buyer is the customer or the utility. By contrast, DevCo/PowerCos need to maintain ownership to support their business model and would be extremely wary of any utility financing partnership that could impinge on this ability.

In general, no deployment model—utility-owned, customer loans, third-party-owned—has a clear advantage in terms of WACC, and each faces additional challenges in terms of monetization of solar tax benefits. As a result, comparing financing costs for these models and assessing the potential for collaboration will require detailed location-specific analysis. Such an analysis should consider the capital costs and structure of the local utility, local financing options available for customer purchases and customer tax appetites based on incomes, and, if applicable, the cost structures and business goals of any third-party solar firms that operate in the area.

- **Supply chain:** In TEP's residential solar program, utility involvement in the supply chain took the form of bulk procurement of solar modules and inverters for the entire program, as well as access to pre-existing storage facilities. While the economies of scale achieved through utility involvement in hardware purchases can reduce costs, they can also be achieved by other approaches, as evidenced by Solarize bulk purchasing programs or other cooperative purchasing programs in Virginia (Irvine, Sawyer, and Grove 2012; "VA SUN" 2016). National Grid's Phase II program offers a different model, in which all hardware was procured by the developer. However, the installed inverters needed to meet certain National Grid-supplied technical specifications to allow the utility to pilot advanced functionality such as voltage control.
- **Operations and maintenance:** The use of industry or utility staff to deliver O&M services for residential solar installations is mixed in the program models examined, and use of one or the other entity will likely be determined by convenience as much as cost. The actual services delivered are relatively standardized and can be delivered by staff from either entity and can make up a small portion of the lifetime cost of the system. For example, despite not having constructed solar facilities themselves, both TEP and KIUC elected to self-deliver O&M services. Also, installer warranties offer coverage for the first several years of project life, shortening the timeframe in which O&M services need to be supplied.

2.5.3 Potential Obstacles to Industry-Utility Collaboration on Soft Costs

As previously mentioned, concerns about appropriate roles for utilities in the competitive solar industry are one of the key issues that must be resolved by state regulators before any collaboration can be pursued. In addition, the value gained by tapping into each party's

respective areas of expertise must exceed the transactional costs in establishing such an arrangement. TEP's model of a portfolio of solar systems at a fixed \$/W cost, subject to certain specifications, is one potential option for partnerships dealing with multiple solar projects; by specifying a fixed portfolio cost, the arrangement avoids the need for numerous project-specific contracts. The turnkey agreements used in National Grid's Phase II program and the EPC contracts used by KIUC are commonly used models in the solar industry for large systems and could also be adopted for future utility-administered solar programs.

3 Community Solar

“Community solar” and “shared solar” are terms used to describe a broad range of solar projects, but they generally apply to projects that feature the following defining characteristics (Coughlin et al. 2012):

- A single solar installation serves multiple participants.
- The solar installation is remote from participants and delivers energy directly to the electric grid.
- Participants voluntarily acquire ownership interests in the energy or capacity of the solar installation.
- Participants receive benefits in relation to their energy or capacity interest in the solar installation.

As with soft costs, community solar programs offer major opportunities for solar PV energy cost reductions and utility involvement. Some of the factors that enable community solar to reduce costs as compared to other solar deployment models include economies of scale from larger project sizes, simpler construction processes when ground-mount systems replace rooftop ones, and optimal project siting to minimize interconnection costs. For their part, utilities have key roles to play in community solar projects, such as interconnecting the systems, identifying and engaging subscribers, tracking energy production and bill credits, and administering the ownership and benefits of projects to their participants. This section describes in detail the current context of community solar, develops and analyzes a regional community solar readiness framework for the Southeast, and finally examines the development of community solar projects to date in the region.

3.1 Background

The business model of community solar has existed for some time; the shared solar installation in Ellensburg, Washington, which claims to be the nation’s first, began generating electricity in November 2006 (“Ellensburg” 2016). Community solar allows consumers who are not able to own or lease their own rooftop solar panels due to structural or ownership issues to access solar through an off-site solar-electric system that offsets their electricity bills (DeShazo, Turek, and Samulon 2015). This arrangement enables multiple energy consumers to share the benefits of a single array while expanding access to solar for those who cannot host their own system.

Since the initial development of the community solar concept, literature on the topic has consistently asserted that there are myriad benefits to community solar (Coughlin et al. 2012; Campbell, Chung, and Venegas 2014; DeShazo, Turek, and Samulon 2015). The benefits may include:

- Improved economies of scale
- Optimal project siting
- Increased public understanding of solar energy
- Local job generation

- Opportunities to test new models of marketing, project financing, and service delivery.

In addition, major recent efforts have focused on key decisions in program design and execution of community solar projects (Chwastyk and Sterling 2015). Major factors in the decisions include the level of utility leadership or involvement and the financial proposition for customers.

The most essential advantage of community solar is that it enables direct participation in solar development and deployment by customers who would otherwise be unable to engage in solar. These customer groups may include renters, homeowners with low credit scores, and building tenants whose roofs are unable to host a solar system. Multiple studies have sought to quantify the size of this solar-restricted market. According to a 2015 NREL/DOE report, 49% of all energy consumers in the residential sector and 48% of all energy consumers in the commercial sector are unable to host a solar PV system (Feldman et al. 2015). Community solar represents an area for tremendous growth for solar PV because it could broaden the potential customer base to nearly 100% of energy consumers, thereby paving the way for widespread solar access and deployment (Feldman et al. 2015). In recognition of this potential, the Obama Administration launched the National Community Solar Partnership in July 2015 to disseminate knowledge about these programs and projects (“Administration” 2015).

3.2 Current Status

Multiple publications have tracked the development of community solar in the United States. The most recent NREL report on voluntary green power programs presents data as of September 1, 2015, and records current deployment as 84 MW across 90 projects in 25 states (O’Shaughnessy et al. 2015). Over half of the existing capacity was concentrated in two states boasting more than 20 MW of capacity each: Colorado, which has seen 37 separate projects developed and Arizona, which has only four projects but which has seen extremely large project sizes from several of the state’s major utilities (O’Shaughnessy et al. 2015).

Projections for future community solar development are heavily influenced by a small group of states that are implementing governing laws to give clear incentives to developers, utilities, and customers. Some 82% of community solar capacity expected to be developed in 2015, and 2016 is anticipated to come from just four states—California, Colorado, Massachusetts, and Minnesota—all of which have community solar legislation in place. In total, the installed capacity of community solar could increase sevenfold over the next two years and could become a half-gigawatt annual market by 2020 (Honeyman, Shiao, and Barati 2015).

This market expansion in community solar will be driven by distinct factors in each state context, with the biggest differentiating factor being the existence and details of community solar legislation and regulation. For states with community solar legislation, solar PV developers will play an increased role in leveraging the pre-existing workforce in these major state markets, gaining access to low-cost financing, and creating vertically integrated business models. In states without community solar legislation, market leaders will likely achieve scale by providing utilities with end-to-end services that extend beyond traditional project development they have seen in the past. Better software platforms for program administration can help utilities strengthen their relationship with customers, and billing software platforms can aid in program administration (Honeyman, Shiao, and Barati 2015). Despite the wide variation in state-level

market development, community solar is nevertheless gaining attention nation-wide because of its ability to dramatically reduce the soft costs associated with solar PV installations.

3.3 Methodology for Regional Assessment

As noted by Honeyman, Shiao, and Barati (2015), the presence or absence of state-level community solar legislation is anticipated to have a major impact on community solar prevalence and program design in the coming years. This report seeks to build on past analysis by assessing the regional context for future community solar development in the southeastern United States, where solar development is subject to a unique array of policy and other factors. This analysis is composed of (1) an assessment of state-level receptiveness for general solar energy development, (2) a targeted consideration of supporting factors for community solar specifically, and (3) an analysis of community solar projects in the Southeast to understand how regional context affects program execution.

3.3.1 Southeastern General Solar Market Context

As a simplified measure, the historical attractiveness of a state-level market for solar energy development can be embodied in the cumulative installed solar capacity in that state. In essence, installed capacity can be viewed as a proxy for the myriad policy, economic, technical, and other factors that support solar development (e.g., renewable portfolio standards, tax incentives, solar rebates and tariffs, high cost of grid-supplied electricity, and strong insolation). For this analysis, we use the state-level installed capacity figures as published in Section 6.2B in the EIA's Electric Power Monthly ("Electric Power Monthly" 2015).

To further investigate which specific factors are present to support solar in a state, this comparison of installed capacity is bolstered by the state-level market characterization framework put forward in *The Effectiveness of State-Level Policies on Solar Market Development in Different State Contexts* (Steward et al. 2014). This report looks at four factors that are useful for understanding the pathways to solar development in each state:

- Personal economic context represented by median household income
- Solar resource availability as represented by the technical potential for solar on rooftops
The cost of competing grid electricity represented by a three-year average residential electricity price
- General community interest in energy conservation and renewable energy represented by American Council of Energy-Efficient Economy (ACEEE) State Energy Efficiency Scorecard score.

From these factors, four types of state-level solar markets are established: Expected Leader, Rooftop Rich, Motivated Buyer, and Mixed. Figure 7 shows how the factors are used to assign states to each of these four types and to which type each of the states in the continental United States has been assigned. Because technical potentials were not available for Hawaii or Alaska, they were not categorized in this assessment.

Table 13. Market-Level Factors Unique to Community Solar

State Market Design Checklist for Community Solar		
Solar Industry Factors	A utility in the state has participated in any type of community solar project.	<input checked="" type="checkbox"/>
Policy Factors	Special supporting provisions in renewable portfolio standard (RPS) support community solar.	<input checked="" type="checkbox"/>
	Virtual Net Metering regulations are in place.	<input checked="" type="checkbox"/>
Customer Base Factors	State has a large number of renter-occupied housing units.	<input checked="" type="checkbox"/>

3.3.2.1 Solar Industry Factor: Community Solar Project Developed in State

Community solar projects, though they may physically resemble other solar energy facilities, possess unique structures in terms of financing, customer engagement, billing and other operations. Given that these represent additional necessary areas of knowledge, experience in these aspects of community solar program design can be highly beneficial, both to the utility having already experienced them and to the broader solar and utility communities in that state. Therefore, we track the number of years since the state’s first community project was developed, as a longer operational history allows for increased knowledge spillovers and customer awareness. We track project history using information from the Solar Electric Power Association’s (SEPA’s) *Community Solar: Program Design Models* report (Chwastyk and Sterling 2015).

3.3.2.2 Policy Factors: Supporting Factors Incorporated in Renewable Portfolio Standard

The presence (or absence) of a renewable portfolio standard (RPS) in a state is a policy factor that is assumed to support all models of solar development, not just community solar specifically. Therefore, its impact is presumed to be captured in the cumulative installed capacity figures used in the general solar market assessment. However, the details of a specific state RPS may provide enhanced benefits for community solar projects, such as allowing the use of utility-owned renewable generation to fulfill RPS requirements. Another supporting feature would be a credit “multiplier” for energy generated from specific types of installations. The details of each state’s RPS are examined using the applicable profiles from the Database of State Incentives for Renewable Energy (DSIRE).

3.3.2.3 Policy Factors: Virtual Net Metering in Place

Virtual net metering (VNM) enables one specific method for utility customers to share in the financial benefits and costs of the electricity output from a single power project, even if the project is not located on a customer’s property. Specifically, it allows the excess generation produced at one site to be used to offset consumption at a second site. As a result, VNM values energy produced from a community solar facility at the full retail rate and provides a similar financial value proposition to rooftop solar. Though it is possible to develop community solar programs in the absence of VNM, 44% of community solar programs have been developed in the 15 states where it is available. The case studies presented in Section 3.5 show strategies to

develop projects in the absence of VNM. The prevalence of state-level VNM policies is tracked using information from the Institute for Local Self-Reliance (“States Supporting” 2015).

3.3.2.4 Customer Base Factors: Large population of renters

As stated previously, nearly 50% of the customer-oriented solar market is untapped as it relies solely on rooftop solar. Prior analysis has identified renter households as a group without access to traditional rooftop solar, making them a potential customer base uniquely accessible by community solar (Feldman et al. 2015). While we acknowledge there are other significant populations without access to rooftop solar—renter businesses as well as building occupants with shaded, structurally deficient or north-facing roofs—the population of renter households is the only component of the non-addressable market for rooftop solar for which data are readily available at the state level. State-level totals from the Census Bureau’s American Community Survey will be used to assess the size of this group.

3.3.2.5 Other Factors Not Included in this Analysis

The analysis that follows is not intended to serve as an exhaustive list of all factors that support community solar program development. Rather, it is an introduction of key factors to consider in assessing state-level readiness and receptiveness. Such a framework may be useful for utilities as a rough indicator of the readiness for community solar in their service territories.

As stated previously, there are many enablers of community solar development—solar tax incentives, solar tariffs and/or rebates for solar—that are not specifically mentioned in this section. Because these mechanisms support all models of solar deployment, their impacts are presumed to be captured in the general solar market assessment through the cumulative installed capacity metric. We considered several factors specific to community solar for analysis but ultimately did not include them due to lack of readily available and standardized data. These factors include the number of environmental justice organizations in a state and the number of customers with shaded, north-facing, or structurally deficient roofs.

3.3.3 Comparison to Leading Community Solar States

Applying this framework to the top 10 U.S. states for community solar program¹⁰ development yields the results shown in Table 14. The results do not yield definitive markers of what has encouraged community solar project development in the past. However, a few details are worth noting:

- Lack of VNM does not appear to be an insurmountable barrier to community solar development.
- The top seven states are all either Expected Leaders (strong customer interest in clean energy and strong technical potential) or Motivated Buyers (strong customer interest in clean energy or high electricity rates and incomes).

¹⁰ We use the number of programs as our evaluation metric instead of total community solar projects or total installed capacity because doing so provides a better indication of how supportive the state environment is to utility pursuit of community solar programs. For example, we would consider a state in which 10 utilities each operate 1-MW community solar programs to be more supportive than a state in which a single utility operates a 10-MW program.

- The clear frontrunners in number of programs—Colorado, Minnesota, and Washington—benefit from special RPS terms, VNM, or both:
 - Colorado has virtual net metering and also offers a 150% multiplier for renewable energy generated by a “community-based” projects under its RPS, such that every 1 MWh generated by these facilities earns 1.5 RECs (“Renewable Energy Standard [Colorado]” 2015).
 - Washington does not have VNM but offers a 200% multiplier for distributed renewable energy generators (under 5 MW) that is owned or contracted by a utility (“Renewable Energy Standard [Washington]” 2015).
 - Minnesota has VNM in place and also requires the state’s largest investor-owned utility (IOU), Xcel, to purchase power generated from community solar projects.
- Iowa and Texas allow utility-owned renewable generation to count toward their RPSs, though the current and future RPS targets in these states have already been surpassed, making this element of renewable generation less valuable in these states.

Table 14. Top U.S. States Ranked by Number of Community Solar Program

State	General Solar Receptiveness		Community Solar Receptiveness				Community Solar Development	
	Natl. Rank	State Type ^a	Years from First Comm Solar Project	Special RPS Provisions	Virtual Net Metering	Natl. Rank of Renter Households	Number of Programs	Capacity of Projects (MW)
CO	9	Expected Leaders	6	Utilities can count UOG, ^b special multipliers	IOU customers only	21	12	26.8
MN	31	Expected Leaders	3	Utilities can count UOG	Xcel Energy customers only	22	11	10.7
WA	27	Expected Leaders	10	Utilities can count UOG, special multipliers	No	13	10	1.1
AZ	2	Expected Leaders	5	Utilities can count UOG	No	15	4	44.2
IA	29	Motivated Buyers	5	RPS target already achieved	No	33	4	1.2
WI	30	Expected Leaders	2	Utilities can count UOG	Northern States Power Company customers only	19	3	1.3
MA	5	Motivated Buyers	2	Utilities can count UOG	All customers	14	2	5.4
MO	18	Rooftop Rich	2	Utilities can count UOG	No	18	2	5.1
TX	11	Rooftop Rich	1	RPS target already achieved	No	2	2	3.9
GA	16	Rooftop Rich	6	No RPS	No	9	2	1.0

^a Source: Steward et al. 2014

^b UOG = utility-owned generation

Darker shadings in the cells indicate conditions considered more favorable for community solar development. Colors used in the table correspond with those used in Steward et al. 2014.

3.4 Results

3.4.1 Southeastern Solar Market Context

Comparing installed cumulative capacity and the more in-depth context from Steward et al. (2014) allows for a more detailed look into the market features of each state in the Southeast. The leader in total installed solar capacity in the Southeast, North Carolina, ranks fourth in the United States for cumulative installed capacity. It is important to note that the top three states ahead of North Carolina in installed capacity are considered Expected Leaders because their American Council for an Energy-Efficient Economy (ACEEE) State Energy Efficiency Scorecard score is above average, and the top three states have an estimated technical potential for rooftop PV greater than or equal to the median. While North Carolina also has an estimated technical potential greater than or equal to the median, its ACEEE State Energy Efficiency Scorecard score is below average, its cost of electricity is below average, and its median household income is below average, pushing it into the Rooftop Rich category. Many other states in the Southeast tend to have characteristics that are similar to North Carolina's and are also categorized as Rooftop Rich, with the remaining states considered Mixed states because of varied results on the four determining factors.

Given the relatively consistent “characterization” of state-level solar markets in the Southeast, it is important to examine why North Carolina has achieved a much higher installed capacity (and installed capacity per capita). Steward et al. (2014) suggest that North Carolina is farther ahead of its neighbors because, while lacking competitive economic conditions due to low electricity prices, the cumulative installed capacity can be attributed to a strong interest from the populous in clean energy-related policies, which drove the development of the state's RPS, tax credits, and favorable off-take terms for utility-scale projects.

Aside from North Carolina, Rooftop Rich states in the Southeast have far lower cumulative installed solar capacity, which Steward et al. (2014) highly attribute to the ACEEE scorecard score. They argue that for Rooftop Rich states, electricity price and income level tend to have a low correlation with installed PV capacity, but policy maturity and public support are major drivers of PV adoption when the economic environment is otherwise unfavorable. This helps explain why North Carolina, a state with the highest ACEEE Scorecard score of the Rooftop Rich group, ranks so highly in total installed capacity.

However, it should be noted that a number of recent policy changes could prove to significantly change the level (or trajectory) of state-level cumulative installed capacity in the Southeast, making that metric a less-valuable predictor of future community solar attractiveness as time goes on. These policy changes include:

- **North Carolina:** Expiration of state-level tax credit for solar installations at the end of 2015 could slow the rate of solar growth in the state (Downey 2015a).
- **Georgia:** The Solar Power Free-Market Financing Act, which entered effect on July 1, 2015, enables third-party ownership of solar systems for the first time and permits utilities and their affiliates to finance solar installations (“HB 57” 2015). This may catalyze growth of deployment, particularly in the residential sector (Williams 2015).

- **South Carolina:** In 2014, the state legislature both established a voluntary RPS (referred to as the Distributed Energy Resource Program) and required the state’s Public Service Commission (PSC) to create net metering rules under SB 1189 (“Bill 1189” 2014). Settlement agreements implementing both programs were filed on May 12, 2015, and they were approved by the PSC on July 15, 2015 (“Distributed Energy Resource Program” 2015). The net metering rules apply to solar installations under 1 MW and establish energy credits at the full retail rate.
- **Mississippi:** The state adopted a modified net metering program in December 2015. Rather than compensating excess generation at the full retail rate, the state’s utilities will be required to credit customers at the wholesale energy cost plus an “add” of 2.5 cents per kWh (“Order Adopting Net Metering” 2015). This adder will be revised within three years based on a detailed study of distributed solar energy value.

3.4.2 Southeastern Community Solar Market Context

While overall solar attractiveness, as indicated by total installed solar capacity, may be a key indicator of whether community solar will be successful in a state, other recognizable market-level factors can make a state uniquely attractive for community solar. Every state in the Southeast was assessed for community solar attractiveness given the following market-level factors, which are described above. The results of this analysis are presented in Table 15, which includes the same categories as Table 14 except for VNM, as no states in the Southeast have this policy in place.

Table 15. Southeastern Regional Context for Community Solar

State	Overall Solar Receptiveness		Community Solar Receptiveness			Community Solar Development	
	Natl. Rank	State Type*	Years from First Comm Solar Project	Special Provisions in RPS	Natl. Rank Renter Households	Number of Programs	Capacity of Projects (MW)
GA	16	Rooftop Rich	6	No RPS	9	2	1.0
FL	14	Mixed	8	No RPS	4	2	0.5
NC	4	Rooftop Rich	1	Utilities can count UOG	8	2	0.2
KY	37	Mixed	2	No RPS	27	1	0.1
TN	22	Rooftop Rich	4	No RPS	16	1	0.0
LA	20	Rooftop Rich	0	No RPS	24	0	-
VA	32	Mixed	0	Voluntary RPS	12	0	-
SC	38	Rooftop Rich	0	Voluntary RPS	26	0	-
AR	43	Mixed	0	No RPS	31	0	-
WV	44	Mixed	0	No RPS	38	0	-
AL	45	Rooftop Rich	0	No RPS	25	0	-
MS	47	Mixed	0	No RPS	34	0	-

* Source: Steward et al. 2014

Darker shadings in the cells are generally considered favorable for community solar development.

No state in the Southeast has VNM or a community solar mandate in place. While VNM is not a requirement for community solar development, national leaders in community solar such as Minnesota and Colorado have implemented VNM policies. Further, no states in the Southeast feature special RPS provisions such as those seen in Colorado and Washington. However, community solar projects could see a boost in attractiveness to utilities if the state has an RPS that will allow utilities to count renewable generation from facilities they own. North Carolina is so far the only state in the region to adopt a mandatory RPS; investor-owned utilities must generate 12.5% of retail sales from renewable energy by 2021, while electric cooperatives must reach 10% by 2018 (“Renewable Energy and Energy Efficiency” 2015). South Carolina and Virginia both have a voluntary renewable energy standard or target. Utilities in all three states are allowed to count energy generated from utility-owned systems toward their compliance obligations.

In terms of customer factors, the three leading states for community solar projects in the Southeast rank in the top 10 nationally in terms of the number of renter-occupied units. The number of projects and total capacity is small to date, but these states now feature community solar experience and high levels of deployed solar—all three rank in the top 16—to complement their large rental populations, potentially setting the stage for future community solar development.

3.5 Case Studies

Some southeastern states are seeing political and regulatory actions to encourage solar development while also witnessing utility actions to participate in solar projects (Gibson 2015). In some cases, this has meant increased interest in community solar projects, with completed projects in Florida, Georgia, Kentucky, North Carolina, and Tennessee. In addition, there are future plans for more community solar in each of these five states as well as South Carolina and Virginia.

To explore how the unique market of the Southeast has impacted community solar project development, phone interviews were conducted with four electric utilities, including investor-owned utilities, municipal utilities, and electric cooperatives. Table 16 summarizes the operational and planned community solar projects in the Southeast, incorporating data compiled for SEPA’s *Community Solar: Program Design Models* report (Chwastyk and Sterling 2015).

Table 16. Utility-Scale Community Solar Case Studies

Southeastern State	Project Name	Date	Project Size (kW)	Ownership	Visibility	Pricing Structure
Georgia	Coastal Electric Cooperative Renewables solar farm	2010	2	Utility	--	Leasing PV Panels
Florida	Florida Keys Electric Co-op Simple Solar Program	2008	200	Utility	--	Leasing PV Panels
North Carolina	Roanoke Electric Cooperative community solar farm	2015	100	Utility	Very visible	Leasing PV Capacity
Tennessee	Duck River Electric Membership Corporation solar farm	2012	25.9	Utility	Very visible	Leasing PV Capacity
Kentucky	City of Berea Municipal Utilities Berea solar farm	2014	28.2	Utility	--	Leasing PV Panels
South Carolina	Duke Energy Carolinas	Planning (2016)	4,000	Third-party PPA or EPC	Visible and Hidden	Buying PV Power
	South Carolina Electric and Gas solar farm	Planning (2016)	400	Third-party PPA	--	--
Virginia	Dominion Power	Planning	--	--	--	--
	BARC Electric Cooperative Community Solar	Planning (2016)	--	Utility	Very Visible	Buying PV Power

Source: Chwastyk and Sterling 2015

From the four interviews conducted by NREL in November and December 2015, and subsequent follow-up research, the following themes have been identified.

3.5.1 State Solar Incentives Support Community Solar Development

Community solar in the Southeast remains nascent, but regulations and policies in some states have made this solar model viable, both to small electric cooperatives and to large utility companies. As previously described, North Carolina is the only state in the Southeast with a mandatory RPS, and it has strong tax incentives through the end of 2015—35% of system costs, up to a maximum of \$2.5 million for systems with a business purpose and \$10,500 for non-business purposes—that encouraged past solar deployment (“Renewable Energy (Personal)” 2015; “Renewable Energy [Corporate]” 2015).

The Roanoke Electric Cooperative Community Solar Farm has emerged as a way to take advantage of state tax incentives and to meet the requirements laid out under the commonwealth's RPS, making it look more like community solar projects being developed in other states with strong regulatory and political incentives for solar.¹¹ It also benefited from unique organizational infrastructure serving electric cooperatives in the commonwealth. After North Carolina's RPS went into effect in 2008, electric cooperatives in the state created GreenCo Solutions, a company owned by the cooperatives and tasked with helping them develop and evaluate renewable energy projects and meet regulatory and compliance milestones, in some cases by acquiring RECs on behalf of member cooperatives. Simultaneously, many of GreenCo's members are also part of the North Carolina Electric Membership Corporation (NCEMC), a statewide generation and transmission cooperative that procures wholesale power and transmission capacity on behalf of the member cooperatives. When Roanoke Electric Cooperative considered developing a community solar project, it realized it had ready partners who could benefit from the RECs (i.e., GreenCo) and state tax credits (i.e., North Carolina Electric Membership Corporation)¹² the project would generate. Roanoke Electric staff indicated that the dual financial benefits of RECs and state tax credits were essential to the development of their community solar project.¹³

Similarly, Duke Energy Carolinas is developing a community solar project with support from state-level incentives. The company is stepping up solar activities in response to the Distributed Energy Resource Program (DERP) Act of 2014, which requires utilities to procure capacity from renewable resources equivalent to 2% the five-year average of peak demand by 2021 ("Bill 1189" 2015). Under the terms of the 2015 settlement agreement between various parties and Duke Energy, a "shared solar" program offered by the utility is eligible to count toward the "customer-scale" portion (roughly 40 MW) of the total DERP target (about 80 MW) ("Settlement Agreement" 2015). Terms of the first shared solar program were submitted to the South Carolina Public Service Commission in October 2015, and approved in November 2015. They include a one-time initiation fee of \$50/kWdc for residential customers and \$100/kWdc for non-residential customers, a \$6/kWdc monthly charge, and energy credits of \$0.0604/kWh for energy produced by the customer's share of the system (Downey 2015b; "Solar Rebate" 2015). While this program has been spurred in part by recent policy activity in South Carolina, it has also benefited from Duke Energy's interest in putting "solar megawatts under [its] belt" and building a fleet of solar generators.¹⁴ Additionally, because Duke Energy's core business is owning and operating infrastructure, and because solar is seen as an attractive asset class, community solar projects are seen as an attractive part of its regulated business.¹⁵

3.5.2 Without State Incentives, Project Developers Seek Out Alternative Support

As many states in the Southeast do not provide direct incentives for solar development, utilities in those states may take advantage of other types of incentives. For example, the key enabling

¹¹ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

¹² As not-for-profit corporations, cooperatives are exempt from state and federal income taxes but do pay sales, property, and other taxes. As the generation and transmission cooperative for all North Carolina electric cooperatives, NCEMC has a larger tax liability than does Roanoke Electric Membership Corporation. See http://ncemcs.com/downloads/NC_economicReport.pdf.

¹³ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

¹⁴ Emily Felt and Stacey Philips. 2015. Duke Energy Carolinas. Phone Interview.

¹⁵ Emily Felt and Stacey Philips. 2015. Duke Energy Carolinas. Phone Interview.

factor for the Duck River Electric Membership Corporation solar farm in Tennessee was the Tennessee Valley Authority (TVA). TVA's Generation Partners Program (now expired) allowed distributors like the Duck River cooperative to sell the energy output of the community solar project to the TVA at the retail rate plus a \$0.12/kWh premium, up to 50 kW of capacity ("TVA" 2016). This volumetric incentive allowed the co-op to easily credit the electric bills of customers who leased solar panels for the 20-year project term. While TVA's incentive delivered operating value to customers, the Duck River cooperative remained responsible for financing the construction of the community solar project. To increase subscription rates, it implemented a payment plan structure—members can finance the \$600 cost of a half-panel ownership unit, about 120 W, for 12 months with no interest—as a way to reduce the upfront capital costs to customers.¹⁶

3.5.3 Pricing, Contract Terms, and Customer Acquisition Reflect Customer Need

The pricing structure of surveyed utility-led community programs in the Southeast is directly correlated with customer acquisition strategies and the demographics of that state or community. For many electric cooperatives in the region, customers' needs are the most important factor when developing a project. This is uniquely true for cooperatives, which unlike other utilities, are owned by their customers. According to several interviewees, these customer-owners have low incomes or are renters (or are both). Some utilities charge a specific rate for the energy produced by the solar farm (e.g., Duke Energy Carolinas and BARC Electric Cooperative) while other programs offer leases on capacity and often provide financing to lower the initial costs of participation (e.g., Duck River cooperative and Roanoke Electric Cooperative). Roanoke Electric offers additional financial flexibility to its customers through a guaranteed pro-rated buy-back option if the customer later decides to sell their share of the community solar project.¹⁷

While there are many similarities among electric cooperatives, BARC Electric Cooperative in Virginia, which is still in the planning phases, took a slightly different approach regarding the pricing structure. Co-op members of BARC Electric pay a onetime subscription fee of about \$50 to participate in the project, but instead of receiving an ongoing on-bill credit, they pay a rate for solar energy produced by the community solar project that is just slightly above the low retail rate in the state. The solar rate is also fixed for 20 years. Set to come online in 2016, BARC's community solar project is already seeing customer participation beyond the available solar generation and the cooperative's staff is looking to begin Phase 2. Because energy from Phase 1 is priced slightly above market, the margin generated will be set aside to build additional phases, including Phase 2.¹⁸

Utilities in the Southeast are clearly focusing a great deal of their efforts on the pricing structure of their projects, due in large part to the already low retail rate of electricity in the region. The key challenge is to manage community solar projects in a way that simultaneously makes solar most affordable to the customers and sustainable for the utility. In fact, most interviewees stressed the financial benefits of participation over environmental benefits to customers.

¹⁶ Steve Oden. 2015. Duck River Electric Membership Corporation. Phone Interview.

¹⁷ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

¹⁸ Mike Keyser. 2015. BARC Electric Cooperative Community Solar. Phone Interview.

Customer acquisition strategies also emphasize the financial benefits of a project. Utilities like Duke Energy Carolinas conducted high-level economic analyses and forecasting while smaller electric cooperatives opted for local community meetings across districts.¹⁹ The goal for all utilities was to try to explain the unique cost structure of community solar to communities that may or may not already be familiar with solar concepts like net metering. Strategies deployed in meetings with BARC Electric, for example, included ideas of no maintenance, no upfront costs, and overall, “worry free solar.” Customer acquisition was also further simplified for customers unfamiliar with the concept of kWh by referring to the solar power customers would receive as “solar blocks.”²⁰ Roanoke Electric Cooperative’s chief executive officer holds seven meetings annually—collectively called the Straight Talk Community Forum—and spends time explaining the simple pricing structure and savings possible for customers of the community solar project.²¹ In general, based on interview findings, utilities that spent time to engage their customer base or conducted well-thought-out analyses and forecasting strategies seemed more likely to have better pricing structures in place, while utilities that overlooked communities receptive to the message about community solar farms continue to struggle to fully subscribe their projects. This is why utility companies in the Southeast are simplifying pricing structures and making strong pushes for better marketing strategies.

Traditional outreach channels, including newspapers, radio, social media, and the web are still heavily used to share information on solar projects with customers, but most utilities find it imperative to explain to customers the benefits that come out of the pricing structure chosen for their project. Most customers want to know what their return on investment will be if they participate. Even though the return on investment can seem low, at 1.5% or 2% for the Roanoke solar farm,²² utility companies are assuring customers that the value can be substantial over time, especially given the stability of the long-term fixed solar energy costs.

3.5.4 Site Selection Driven by Cost First, Visibility Second

One aspect of system design that intersects with marketing strategies is the decision to locate solar farms in areas that are visible to customers. Some utilities argue there is anecdotal evidence from customer focus groups that it would be best to make the project physically visible so that community solar participants can see the results of their participation. However, in the end, most utilities state that community solar project location issues are primarily determined by the cost of the land and resulting effects on cost of energy and customer value, with location visibility a secondary concern; this observation is supported by preliminary results of SEPA’s customer preference research, which stated that economic benefits are the number one concern of potential customers (Chwastyk and Sterling 2015). Some utilities may be able to achieve both by taking advantage of free land or land at their headquarters that are located in high-traffic areas. The co-op that operates the Roanoke solar farm, located on a busy country road in North Carolina, decided to utilize their own land within their headquarters, thus reducing the cost of the project and simultaneously making it visible.²³ The co-op also conducts tours of the solar farm and is

¹⁹ Emily Felt and Stacey Philips. 2015. Duke Energy Carolinas. Phone Interview

²⁰ Mike Keyser. 2015. BARC Electric Cooperative Community Solar. Phone Interview.

²¹ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

²² George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

²³ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

considering personalizing the solar panels by putting the names of its member-owners on the back of each panel.²⁴

3.6 Discussion

The projects being developed by Roanoke EMC and Duke Energy Carolinas show how state-level regulatory incentives can encourage community solar development by utilities in the Southeast. While the success of North Carolina's policy regime in supporting solar development has been well-documented, it is interesting to note how quickly the implementation of supportive policies in South Carolina has encouraged community solar project development; enabling legislation was passed in 2014 through Bill 1189, regulatory settlements were completed in summer 2015, and community solar program plans were submitted in fall 2015.

An obstacle specific to electric cooperatives is the ability to access federal tax credits to reduce the cost of their community solar installations. According to interviews, the Duck River Electric Membership Corporation was not able to receive the ITC due to its tax-exempt status, while Roanoke had to rely on other supporting organizations to realize the value of this incentive. The experience of these cooperatives echoes that of Kauai Island Utility Cooperative in its development of two utility-scale projects. Unable to realize these tax benefits on its own, KIUC established an independent, for-profit holding company for each project. While this allowed access to the tax credits, it had the unintended consequence of disqualifying these assets from being covered through the discounted insurance policies available to cooperatives, which cover KIUC's other capital assets. Despite missing out on the ITC, the Duck River cooperative was still able to go through with its community solar project by accessing the premium pricing structure available from TVA for solar generation.

²⁴ George Stamper. 2015. Roanoke Electric Community Solar Farm. Phone Interview.

4 Normalization Accounting Rules and Utility Ownership of Solar Assets

4.1 Background

Normalization accounting rules, as codified in the Internal Revenue Code and as promulgated by Congress, require that utilities “levelize” the effects of certain tax benefits over the lifetime of the assets with which the benefits are associated. Ultimately, this prevents rates from decreasing in the years that the benefits occur and then rising again in the years in which the benefits have expired. This equalizes the benefit for ratepayers over time while also protecting utilities from revenue losses in years when rates would be low because of a reduced income tax component (owing to the effects of the tax benefit). The motivation behind normalization requirements as promulgated by Congress is that the accelerated depreciation and the ITC are intended to incentivize capital investment and not to subsidize ratepayers. Moreover, direct flow-through of the tax benefits to ratepayers had the double effect of reducing a utility’s federal income tax once from the benefits themselves, and then again from the reduction in revenues from reduced rates (Matheny 2015).

Because it spreads the tax benefits of a particular asset over the useful life of that asset, normalization accounting also depletes the absolute value of the tax benefits owing to the time value of money. For example, consider a utility-owned asset that qualifies for a five-year modified accelerated cost recovery system (MACRS) schedule. This schedule allows the asset owner to fully depreciate the qualified basis by year six of that asset’s operation, thus generating book losses that will reduce the owner’s taxable income. Instead of passing through the benefit of a reduced tax burden to its customers as a reduction in rates (as would happen in a flow-through accounting arrangement), the utility records this capital shielded from income tax in a deferred tax reserve account and draws it down year-over-year as book depreciation levels exceed tax depreciation levels for 20 years. Each year that portion is worth less than the year before depending on the discount and inflation rates. At a 6% discount rate, for example, MACRS benefits could lose half of their original value if spread over a 20 years (see Text Box 1).

This can put utilities at a disadvantage relative to independent power producers (IPP) when it comes to the pricing of renewable energy generation. IPPs are not subject to normalization requirements and can therefore pass on in their pricing the full value of the tax benefits in the years in which they occur, which can account for over 50% of the capital costs of a qualifying renewable energy project²⁵ (Martin 2015). When utilities must develop rates that pass on these tax benefits ratably over the life of the asset, their pricing of generated energy is typically higher than what an IPP could offer through a PPA.

This effect that normalization has on the economics of renewable energy has largely prevented utilities from investing in solar PV at a time when such investments could make strategic sense. Falling costs, ratepayer interest, carbon regulations from the Environmental Protection Agency’s Clean Power Plan, portfolio standards, the growing presence of residential solar service providers, and other drivers have made it such that utilities have become increasingly interested

²⁵ This does not account for the “leakage” that is associated with the tax benefits’ monetization by tax equity investors. For more on this, see Bolinger (2014).

in directing their capital to solar PV technologies. However, utility regulators (referred to in this report generally as public utility commissions, or PUCs) have disapproved proposals for solar asset ownership because the effect on rates would have been greater than if the utility were to have simply purchased solar power from an IPP.

4.2 Normalization Effects on Pricing of Energy

Text Box 1. Tax Credit Value Depletion from Normalization Accounting

The reduction in a tax credit's value to a project (as reflected in the cost of energy) imparted by normalization accounting treatment is a function of the discount rate and the lifetime of the project. For example, in a \$1 million solar project with a 5% weighted average cost of capital (discount rate), the ITC would be worth \$300,000 and five-year MACRS would produce roughly \$807,000 in losses (on a net present value basis) within the first six years of project operation. However, if these benefits were to be normalized over a 30-year period, and discounted at the project's 8% cost of capital, they would be worth less than 38% of these original values. The following tables show the percentage losses of the ITC and MACRS as normalized over 20 and 30 years at various discount rates.

20 Years		30 Years	
Discount Rate	Percentage Loss Due to Normalization	Discount Rate	Percentage Loss Due to Normalization
12%	62.65%	12%	73.15%
11%	60.18%	11%	71.02%
10%	57.43%	10%	68.58%
9%	54.36%	9%	65.75%
8%	50.91%	8%	62.47%
7%	47.03%	7%	58.64%
6%	42.65%	6%	54.12%
5%	37.69%	5%	48.76%
4%	32.05%	4%	42.36%
3%	25.61%	3%	34.67%
2%	18.24%	2%	25.35%

An IPP's cost of capital, profit margins and overhead, access to bulk purchasing of equipment, and other aspects of its business model will influence their ultimate pricing for energy services.

These variables make it difficult if not impossible to directly compare a regulated utility and an IPP, and thus isolate the sensitivity of pricing to normalization accounting treatment.

As a heuristic exercise, we adapted NREL’s solar Cost of Renewable Energy Spreadsheet Tool (CREST),²⁶ a pro forma project calculator, to investigate the effects of normalization on the levelized cost of electricity (LCOE). This exercise does not take into account the gamut of variables that differentiate utilities from IPPs, but it is instead intended to observe, through a simplified lens, how normalization affects project competitiveness in an “all-else-equal” type scenario. Table 17 lists the inputs and values used to run the model. All inputs not listed were left at the default value.

Table 17. Inputs and Values for CREST Model Runs

Input	Value
Project Size	1,000 kW
Project Location	Virginia
Total Installed Cost	\$1.60/W
O&M	\$15/kW/yr
O&M Escalator	2%/yr
Equity Portion	100% ^a
Target After-Tax Equity Internal Rate of Return (IRR)	8.5%
State Incentives	Performance-based (RECs)
State Incentive Rate	\$15/MWh ^b
State Incentive Duration	10 yrs
Equipment Replacement	\$0.15/W (inverter)
Equipment Replacement Timeline	10 and 20

^a These model runs do not take into account a varied capital structure (i.e., a split between debt, sponsor equity, and tax equity). Instead they treat the “after-tax equity internal rate of return (IRR)” as the project-weighted average cost of capital, which is a figure that would include the various proportions and return rates of the different sources of capital in the stack. The 8.5% chosen for this analysis is intended to approximate a “market” project return rate. CREST calculates the cost of energy based on the price at which the project “breaks even” (i.e., where the net present value of cash flows reaches 0 or near 0 at the end of the project).

^b In this scenario, we assumed the project sponsor sold the RECs into the Pennsylvania market (which was offering \$15/MWh at the time this analysis was performed). Virginia’s market is voluntary, and therefore REC sales can be highly uncertain.

Using these inputs, we run the model to determine a baseline year-one cost of energy (Table 17). We then take the value of the ITC (\$452,200) and spread it evenly across the 25 years of project life so that the project received a tax credit of \$18,048 per year for each year of the analysis period. For the MACRS deduction, we perform a net present value calculation on the total MACRS benefit over six years, discounting at the rate of the project’s after tax IRR (8.5%). We

²⁶ CREST models are available at <http://financere.nrel.gov/finance/content/crest-cost-energy-models>.

then took this figure (\$1,024,622 in losses) and allocate it evenly over the analysis period so that the project received \$40,984 of tax losses each year for 25 years (Table 18).

Table 18. Values for Non-Normalized and Normalized Tax Benefits

Tax Benefit	Value
ITC Value (non-normalized)	\$452,200
ITC Value (normalized)	\$18,048/yr
NPV MACRS Deductions (non-normalized)	\$1,024,622
MACRS Deductions (normalized)	\$40,984/yr
Discount Rate	8.5%

Table 19 shows the percentage increase in year-one cost of energy over the baseline—nearly 53%— after the tax benefits are normalized according to our method. Utilities may find other means of compressing costs—for example building on lands they own or facilitating the interconnection process—that could help mitigate such cost increases.

Table 19. Cost of Energy under Non-Normalization, Normalization, and Reduced Cost of Capital with Normalization Scenarios

Scenario	Cost of Energy	% Change from Non-Normalization
Non-Normalization (baseline)	\$0.1175*	0%
Normalization	\$0.1795	+52.77%
Normalization and 4.8% project IRR	\$0.1175	0%

The price of \$0.1175 is high for solar energy, especially in the wholesale market where solar projects are competitively bidding against combined cycle assets in some states with strong solar resources resource. The figure (\$0.1175) is not intended to be an exact estimate of the cost of solar energy but merely a baseline for understanding the changes imposed by the application of normalization accounting for the tax benefits.

One particular advantage that utilities may have over IPPs is in their cost of capital, which for investment-grade rated utilities can be lower than that of an IPP (which because of merchant generation business model and other factors may be perceived as riskier by ratings agencies and other investors). To reflect how this difference could affect the cost of energy, we reduced the normalized project’s after-tax IRR to identify the percentage (4.8%) at which the year one-cost of energy matched that produced in the baseline (non-normalized) scenario.

The assumptions and modeling environment used for this heuristic exercise are simplifications and should not be taken to reflect actual utility accounting methods. They are instead meant to illustrate at a high level the effect that normalization accounting can have on the value of tax benefits, and thus project LCOE, owing to the time value of money.

4.3 Methodologies for Utility Investment in Solar

Utilities must comply with normalization requirements if they are to receive the tax benefits associated with investment in a given asset. No exceptions to this rule have yet been granted by the Internal Revenue Service (IRS) or Congress for the purpose of investing in solar. However, it may be possible for a utility to receive regulatory approval to invest in solar PV projects that serve only one customer or a subset of customers while still being subject to normalization requirements (and the economic effects therewith), provided the cost recovery from such investments is not spread to non-participating customers. For such projects that serve only one customer or a subset of customers, a utility would have to segregate costs for the project to sufficiently demonstrate that non-participants are not being affected from a cost perspective.

Additionally, tax treatment may be different in cases where projects involve certain customers, whose relationship with the utility is not subject to utility commission regulation. For example, a July 2015 private letter ruling (PLR) recognized that normalization requirements do not pertain to facilities dedicated to certain customers within Dominion Virginia Power's service territory that are "non-jurisdictional" (i.e., entities whose rates are not subject to PUC approval). These non-jurisdictional customers are predominantly government agencies, and at least one of them is a military installation. Each branch of the military has a 1-GW renewables procurement target in place (GTM Research/SEIA Solar Market Research 2015), so there is an identified interest in renewable energy procurement within this "non-jurisdictional" customer base.

However, even though the PUC does not have authority to regulate the utility's relationship with non-jurisdictional customers, state law and/or PUC regulations may still require prior approval of the state PUC to construct a facility, while the specifics with respect to recovering the costs of such facility would require only bilateral negotiations between the utility and the non-jurisdictional entity. In fact, Dominion has already executed a contract with one such entity and received the relevant PUC's construction permit. The PLR establishes that the IRS does not hold assets built to service these non-jurisdictional customers as public utility property under former Section 46(f), and Section 168(i)(10), which codifies the definition of public utility property and normalization requirements for depreciation deductions among other things (Internal Revenue Service 2015). Accordingly, the PLR suggests that Dominion could not only build a solar plant to service its non-jurisdictional customers without obtaining PUC approval for the contract rate, but it could do so with exemption from the financial accounting impacts of normalization for the ITC. Avoiding these measures would facilitate Dominion's effort to offer a competitive price for solar energy to its non-jurisdictional customers.

PLRs are meant to clarify the tax treatment (in this case, that of investment tax credits) based on specific conditions of the requesters, and they should not be used as precedent for other taxpayers. In other words, this PLR may provide Dominion with the ability to make solar investments in a limited forum, but it does not pave the way for a market.

Text Box 2. Normalization of the ITC

Normalization requirements for accelerated depreciation are codified in Sections 168(f)(2) and 168(i)(9) of the Internal Revenue Code, but there are no such dedicated sections for the ITC in the present day code. This is because the section that formerly housed these rules (originally 46(e) and later 46(f)) was repealed in 1990 as part of the Revenue Reconciliation Act). Despite this repeal, the requirements of this section are still applicable to public utility property, and they are invoked by both the code and Congress as providing the relevant framework on how to normalize the ITC. A series of PLRs for specific taxpayers has also provided some administrative guidance, though, in general, the normalization requirements for the ITC remain challengingly complex (Matheny 2015).

The Revenue Act of 1971 established three methodologies by which utilities could normalize the ITC, and which utilities elected to adopt in 1972. That choice has been unalterable for utilities to the present day, though one option—Option 3—has since been repealed (in the Recovery Tax Act of 1981). Utilities that elected Option 3 must now use either Option 1 or Option 2 depending on their original election in 1972.

- **Option 1: General Rule:** Option 1 allows utilities to reduce their rate base (the amount of money invested in plants and equipment for the supply of electricity) by the amount of the credit upon receipt, provided the reduction is reversed ratably or faster than ratably over the life of the asset. For example, a \$10 million solar project with a useful life of 30 years would receive \$3 million. A utility that owned the same project and which was subject to Option 1 could reduce its rate base by \$3 million in the tax year in which the credit was claimed. Thereafter, this reduction could be restored at a rate no slower than \$120,000 per year. Option 1 prohibits any cost of service reductions associated with the ITC. This is, however, allowed in Option 2.
- **Option 2: Ratable Flow-Through Method:** Instead of reducing their rate base, utilities that elected Option 2 are allowed to flow through the amount of the ITC to their ratepayers on a ratable basis over the life of the asset. In other words, the ITC can reduce cost of service evenly each year of the asset's useful life, instead of a deep, singular reduction in year one (Matheny 2015; SEPA 2012).

4.4 Case Studies

4.4.1 Public Service Enterprise Group of New Jersey

Just as Dominion is exploring strategies for solar investment that are predicated on special circumstances, other utilities have employed similar strategies. In New Jersey, where robust and longstanding incentives have created one of the largest PV markets in the country, the utility, Public Service Enterprise Group (PSE&G), has found two means of making regulated investments in solar. The first is a loan program that PSE&G structured around the SREC market and which can offer homeowners and businesses financing to install rooftop systems. Because PSE&G does not own any assets through this program, it does not have access to any tax

benefits, and therefore has no need for normalization accounting. The debt capital the utility deploys to homeowners is recoverable through rates.

As of this writing, the loan program counts 1,000 residential and business customers who have accessed the program, amounting to about 80 MW deployed. However, complications with the loan product have limited its appeal among consumers, and more homeowners in New Jersey appear to be opting for the more streamlined lease and PPA products from third-party finance providers. The PSE&G loan covers only a portion of the system (typically around 50%, depending on the specific terms of each loan and the cost of the installation), which means that borrowers must come up with either cash or another loan (e.g., home equity) to finance the remainder. Participants are also responsible for administrative costs. Third-party products typically do not require money down and can offer consumers solar energy at a lower cost than prevailing electricity rates on day one of their contract (though the contract may include escalators that may exceed the utility's own rate escalation). Moreover, while the PSE&G loan can be repaid almost entirely with SRECs, system owners must enter into a bid process to establish a price floor for those SRECs, which adds another layer of complexity. However, despite a somewhat limited uptake among its customer base, the New Jersey Board of Public Utilities (BPU) has approved a renewal of the program for additional 97.5 MW of additional capacity (PSE&G 2015).

PSE&G has also received approval from its BPU to make direct regulated investments in solar projects that it can build into its cost of service, though the value of these investments is reduced by revenues received from energy sales into the PJM market; this treatment is similar to National Grid's solar program as described in Section 2.4.2.2. The program through which PSE&G builds, owns, and operates these projects is called Solar 4 All. The program was reauthorized by the BPU in 2013 to add 45 MW for a total cap of 125 MW, 42 MW of which is slated for landfill and brownfield development.

The BPU's history of approvals for the Solar 4 All program was influenced by conditions that were singular to the New Jersey market, namely the need for SREC price controls and policy goals of increasing solar development on landfills and brownfields. Before spring 2011, when the price of New Jersey SRECs was consistently above \$600/MWh, the BPU was interested in establishing a ceiling price to protect ratepayers from the potential price shocks of high incentive levels. Accordingly, they granted PSE&G the ability to build, own, and operate solar projects to bring more capacity to the market and bring the per MWh price of SRECs down to sustainable levels. However, even without PSE&G's influence in the marketplace, private developers flocked to New Jersey to take advantage of the SREC prices, and the price dropped to a low of \$85/MWh in December 2012. The SREC price has since rebounded, hitting its highest levels in nearly four years in November 2015 (\$285/MWh); though even at this level, there is no perceived need for a market ceiling, and PSE&G is not regarded as a critical entity in setting this limit.

PSE&G's other value-add is that they are comfortable with the risks associated with landfill and brownfield development where other developers may not be. This has given them a niche in fulfilling the state's policy goals of deploying more solar on these sites. However, more private developers have been finding comfort with and devising successful mitigation strategies for brownfield risk in recent years. In fact, the BPU's most recent approval decision for the Solar 4

All program in May 2013 indicates that the regulators discern a smaller role for PSE&G in the state's solar market through direct investment. As mentioned, the BPU allocated 45 MW of capacity to the program extension, which was considerably less than the 136 MW that the utility had sought (NJ BPU 2013).

4.4.2 Arizona Public Service

As of Q3 2015, APS owned and operated 189 MW of utility-scale solar capacity (170 of which was built through its AZ Sun program), and it had another 9 MW in development. The utility also has filed an application with Arizona Corporation Commission (ACC) requesting approval to build, operate, and own an additional 20 MW of utility-scale plants as part of its AZ Sun program (Pinnacle West 2015). Furthermore, as documented in Appendix A, APS will own potentially up to 20 MW of DG through their Solar Partner Program, which was the ACC authorized in December 2014. However, it is unclear whether APS can seek cost recovery for this program, as the ACC's approval stipulated that the project portfolio must be placed in service and APS must present another rate case before the assets may be considered for the rate base.

As per the requirements of the Internal Revenue Code and promulgations of Congress, APS uses normalization accounting treatment for the tax benefits on all solar assets under their ownership. However, any differentials in the cost of energy of these utility-owned assets and those of IPP-owned solar assets—APS also has 310 MW of solar PPAs—have not proven to be a significant drawback in the consideration of the ACC. In personal interviews with NREL, APS identified several non-economic factors that entered into the ACC decision-making process to allow for utility-ownership of solar projects. These included APS's track record in completing projects (which, as a ratio to abandoned projects, is higher than for most developers); the ACC's recognition of importance of fuel-source and technology diversity in the utility's asset base; and the fact that the strong resource in the Southwest (where APS's assets are located) erodes some of the project's economic effects that normalization accounting can impart (i.e., the price reduction effect of higher generation has a greater effect per kWh of LCOE than the price-increasing effect of normalization). APS also pointed to the fact that they will derive value from their assets over the entirety of useful life as opposed to projects with which they sign 20-year PPAs. Because they can account for the residual value of projects that they own in their financial models (whereas a project with a PPA may not be able to assign much value to the backend of its useful life), APS can further push back against the economic effects of normalization.

APS's relative success in its bid to own a solar a solar fleet demonstrates that the economic effects of normalization, in and of themselves, do not necessarily represent a deal-breaker to regulators. Non-economic considerations and regulatory cultures can also figure prominently into PUC decision-making.

4.5 Discussion

Utilities have largely remained on the sidelines as investment in solar PV infrastructure has grown in recent years. Total U.S. capacity is anticipated to achieve as much as 24 GW in 2015 and at least another 10 GW in 2016 (GTM/SEIA 2015). As the traditional owners and operators of the U.S. electric grid, utilities will continue to manage distribution and transmission infrastructure as solar deployment increases. Now, utilities are also beginning to join in solar

development by making direct investments and taking owner/operator positions in solar generation assets, just as some utilities have owned and operated generation assets for decades. However, the economic effects of the normalization ratemaking requirements for tax benefits can place utilities at a disadvantage with IPPs. This, among other factors, can make it difficult for them to obtain the required approval from their regulators to build solar projects.

However, there may be creative options for utilities. Certain provisions of the tax code (“non-jurisdictional” customers whose rates are set bilaterally can be serviced by non-public utility property) and certain structuring arrangements (ring-fencing and customer segmentation) could allow for investment that either does not require PUC rate approval or would not require normalization impacts on such rates. Moreover, if utilities can demonstrate to their PUCs that they fulfill certain niches—for example, they have a special expertise, or can fill financing gaps in the marketplace—there is a possibility for approval of solar programs that are priced subject to normalization requirements.

Today, there are expanding opportunities for utility-owned solar but financing issues remain a key challenge. However, as more utilities bring their cases before their PUCs and the IRS, and as market conditions shift, utilities could be strong players in the solar market of the near-term to midterm.

5 Conclusion

This report seeks to support the development of a utility-administered solar strategy in the Commonwealth of Virginia. In pursuit of this mission, issues of soft costs, utility business models for solar, community solar programs, and tax normalization issues have been considered. From the information and analysis in this report, we summarize several key considerations for stakeholders to weigh when evaluating the potential for industry-utility engagement in solar:

- The potential for industry-utility collaboration to reduce soft costs should be further explored. Customer acquisition and insurance issues have been identified as two areas to potentially reduce costs and increase deployment, but the terms and structure of collaborations will need to be considered. Prevailing business models and levels of development in local solar industries will affect opportunities for engagement.
- Competitive considerations regarding utility participation in solar are the purview of relevant authorities in each state and will need to be evaluated with consideration for that state's specific economic and environmental goals.
- Community solar projects continue to be developed throughout the United States despite varying levels of policy support. The nation's three leading states for community solar have instituted community-solar-supportive RPS terms, VNM policies, or both. Larger projects have been developed in states without such policies, potentially to compensate for lack of support by achieving greater economies of scale. Cooperatives have taken a lead in community solar development in the Southeast; they benefit from greater levels of engagement with member-owners but can face unique financing challenges as not-for-profit entities.
- Tax normalization issues merit greater consideration following the December 2015 extension of the ITC, as this will remain a differentiating factor for the cost of solar energy from utilities and IPPs at least through 2021. Costs of solar energy from either party can also be affected by myriad factors, including cost of capital, labor rates, access to suitable sites, and economies of scale from procurement.

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Appendix A: Utility Program Profiles

To understand how utility solar programs can be designed to minimize soft costs, it may be useful to examine how utility solar programs have been structured in the past. This appendix describes several solar programs serving the residential, commercial, and utility-scale customer segments that feature major involvement from electric utilities.²⁷ For each segment, a framework is developed to consistently compare programs across major elements of program design. These frameworks then serve as the basis for detailed comparisons in the text. The set of programs profiled is not meant to be comprehensive of all utility-administered solar programs. Instead, the programs are intended to highlight a diverse set of program models and experiences.

Utility-Administered Residential Solar Programs

Utility-administered residential rooftop solar programs have grown over the past several years. Many factors are driving this rapid growth: (1) potentially reducing or eliminating investment in new distribution system infrastructure, (2) piloting voltage control from advanced inverters, (3) managing peak load on feeders by coupling with storage or facing the system westward, (4) avoiding financial and legal complications associated with control of non-utility DG PV systems, and (5) reaching underserved customers who might not otherwise be able to access solar (APS 2014; AZCC 2014).

In 2014 and 2015, five utility-administered solar rooftop programs were launched. While it is too soon to judge the long-term success or failure of these programs, it is still possible to derive “lessons learned” in terms of the conceptual basis, formation, and launch of these innovative models. Table A-1 summarizes these five programs across a set of relevant parameters. The models in the table are not the only existing models for utility engagement in residential solar. REC purchase programs,²⁸ premium solar purchase rates,²⁹ and rebates on installed costs³⁰ are all common program types that have been deployed for many years. The models in Table A-1 have been selected both for the high level of involvement by the utility and their relatively recent emergence.

²⁷ In this report, we define three solar PV market segments: (1) *residential*: a solar PV system that generates energy for the direct benefit of the occupants where the system is installed and system sizes are typically below 20 kW, (2) *commercial and industrial*: a solar PV system installed on or next to a commercial or industrial building, which produces energy for the benefit of the owner or tenant with system sizes ranging from several kW to multiple MW, and (3) *utility-scale*: a ground-mounted solar PV system with no associated electric load that produces energy for resale and with system sizes that are not strictly defined in this report but are often 1 MW or larger.

²⁸ e.g., PNM’s Customer Solar Energy Program (<https://www.pnm.com/solar>)

²⁹ e.g., Dominion Virginia Power’s Solar Purchase Program (<https://www.dom.com/residential/dominion-virginia-power/ways-to-save/renewable-energy-programs/solar-purchase-program>)

³⁰ e.g., City of Fort Collins Solar Rebates (<http://www.fcgov.com/utilities/residential/renewables/solar-rebates/>)

Table A-1. Comparison of Utility Residential Solar Programs

	Tucson Electric Power (TEP)^a	Arizona Public Service (APS)^b	CPS Energy^c	ConEdison Solutions^d	Georgia Power^e
Program Name	Residential Solar Program	AZ Sun DG	SolarHost	SunPower Partnership	Solar Consultation
Start year	Sep 2014	Dec 2014	Sep 2015	July 2015	July 2015
Size (MW)	3.5	20	5	--	--
State	Arizona	Arizona	Texas	New York	Georgia
Asset Ownership	Utility	Utility	PowerFin Partners	Utility Subsidiary	Customer
Energy Ownership	Utility	Utility	Utility	Utility Subsidiary	Customer
REC ownership	Utility	Utility	Utility	Utility Subsidiary	Customer
Construction and Maintenance	Solar installers	Arizona solar installers	PowerFin Partners	SunPower	Installer/Utility Subsidiary
Business Model	Customer pays fixed energy rate and initial processing fee	Roof rental payment and fixed bill credit by utility	Roof rental payment and bill credit by utility as per solar energy generated	Customer pays monthly lease payment	Regulated utility offers solar assessment, refers to installers (incl. utility subsidiary)

^a AZCC 2014a, “Residential Solar Program” 2016

^b “Solar Partner Program” 2015

^c Trabish 2015a

^d Trabish 2015b; “ConEdison Solutions” 2015

^e Pyper 2015

The information in Table A-1 coupled with in-depth research on these programs resulted in the identification of five major themes in residential solar programs.

1. Major Differences in Services Offered

The first key theme is the major differences in the services offered across programs. The two Arizona IOUs offer very similar programs, compensating the homeowner in return for hosting a utility-owned solar system on their roof. CPS Energy has a very similar program, though their arrangement is unique in that the value of compensation is directly tied to the output of the hosted solar system (compensation schemes for all programs are compared in detail below). ConEdison, through its unregulated project development arm, ConEdison Solutions, offers a third-party lease. In this model, ConEdison Solutions installs a system on the customer’s roof and leases it to them, allowing the customer to benefit from the energy offsets created under the state’s net metering program. In essence, this third-party offering is similar in structure to third-party leases offered by other non-utility companies. Finally, Georgia Power has an entirely

different offering; the regulated utility offers a web- or phone-based solar assessment to its customers to help them to determine whether installing solar is a viable option. If the assessment suggests that it is, Georgia Power connects the customer with pre-screened solar installers in their area, one of which is Georgia Power's unregulated developer Georgia Power Energy Services.

2. Wide Variation in Involved Parties

Across the five utility programs, there is wide variation in involved parties, including regulated IOUs, (TEP, APS, Georgia Power), municipal utilities (CPS Energy), unregulated utility subsidiaries (ConEdison, Georgia Power Energy Services), third-party owner-installers (PowerFin Partners), solar installers (partners under TEP, APS and Georgia Power programs) and module manufacturers (SunPower). This mix of involved parties and variation in their roles indicates that the utility-administered solar space may be in a period of experimentation in terms of program models, as no uniform or dominant model has emerged.

Across the surveyed programs, only the Arizona IOUs retain direct ownership of the solar assets. CPS Energy uses different a structure in which ownership of the asset is handled by the contracted installer, PowerFin Partners, from whom CPS Energy buys the energy output of the systems. ConEdison Solutions will own the solar assets constructed under their lease offering, an arrangement that does not affect the financial performance of the regulated utility. Lastly, Georgia Power retains no ownership interest in the installed solar systems, whether they are installed by the preselected installer partners or by Georgia Power Energy Services. Further, as of December 2015 neither Georgia Power nor Georgia Power Energy Services offered financing under this program

The other key aspect of program participant roles is the involvement of the regulated utility. The Arizona IOUs hold an asset ownership role in their programs, but they also perform other key responsibilities that include:

- Generating leads and acquiring customers
- Selecting installer partners via competitive bids
- Procuring modules and inverters for the installed systems
- Compensating program participants through the utility's chosen mechanism.

By contrast, Georgia Power's role in its solar program is confined to lead generation, as the regulated business has no further involvement with customers once they have been referred to the program's pre-screened installers—even if the customer ultimately selects Georgia Energy Services. ConEdison is even further removed from the ConEdison Solution solar program, maintaining no involvement whatsoever. This assessment is less relevant to CPS Energy as a municipal utility; its major roles are customer acquisition, energy and renewable energy certificate (REC) purchases from PowerFin Partners, and billing coordination to deliver credit to participating customers.

3. Compensation for System Hosts Varies Widely

Just as service offerings and participant roles vary widely, so do the compensation mechanisms for the residential solar program customers. The Arizona utilities chose customer value propositions that completely decouple the level of compensation from the output of the installed solar system. APS offers a \$30/month bill credit to all hosts, while TEP freezes the customer bill at a baseline level so long as future annual consumption remains within 15% percent of the baseline value. CPS Energy's program, by contrast, compensates the customer in proportion to the energy produced by their hosted solar system at a rate of \$0.03/kWh, delivered as a monthly bill credit. ConEdison Solutions' value to the customer is similar to that of any third-party lease by reducing the utility bill via the net metering of their energy output in return for fixed lease payments on their solar system. Finally, Georgia Power has no role in the compensation of participants in their program; customers who choose to install solar systems benefit from reductions in energy consumption and from any bill credits achieved through the state's net metering regulations.

4. All Programs Use Non-Regulated-Utility Labor for Installation

One common theme across the surveyed utility offerings in residential solar is that none of the programs uses regulated utility employees to design or install the solar PV systems. This is not a fully developed competency within these organizations, but it is readily available from the solar installer industry or in the unregulated arms of the utility, even if utility staff (e.g., an electrician) already performs related functions. APS, TEP, CPS Energy, and Georgia Power all leverage local installers to perform actual construction of the systems, while ConEdison Solutions and Georgia Power Energy Services perform this role as unregulated developers. Of special note is how these utilities engage the installer partners to participate in their programs. APS and TEP each held competitive solicitations for multiple installers, seeking bids in terms of an average cost per watt across a portfolio of solar systems. CPS Energy held a competitive solicitation as well but instead sought just a single program administrator to build and own the solar systems (Chapa 2015). Finally, Georgia Power prescreens local installers and then connects potentially interested solar customers with them (Pyper 2015).

5. All Surveyed Utilities Retain RECs (where applicable)

All surveyed utilities retain the RECs produced by their solar systems, as this is an important value stream to meet their compliance obligations (and to avoid the cost of procuring these credits through other means). Avoiding this cost may generate savings that can be passed on to customers through lower system prices, especially given the ability of the utility to aggregate RECs and lower transaction costs if later selling them. Interest in retaining the RECs from utility residential solar systems is greater in states with special RPS provisions requiring a certain share of renewable requirements be met from distributed or customer-sited generation (as in Arizona and New York) or from solar (as in other states with solar-specific carve-outs). This strategy is less valuable in Texas, where REC prices have consistently remained below \$2/MWh with capacity targets for renewable energy already met, and the strategy is not applicable in Georgia, which does not have an RPS (“Renewable Energy Certificates” 2015).

Utility-Administered Commercial Solar Programs

Electric utility companies have been major participants in the development of systems for commercial customers for some time. In particular, 2008 and 2009 saw a wave of solar PV program launches in the commercial sector. The larger system sizes, greater REC-generation potential, greater electrical system impacts and capital costs, and lower customer engagement and transactional costs per unit of installed capacity made the commercial sector a natural avenue for utilities to engage in customer-sited solar development while gaining knowledge and experience on operating solar DG. Table A-2 summarizes the key features of seven utility-run commercial solar programs across six U.S. states.

Table A-2. Comparison of Utility Commercial Solar Programs

	Dominion Virginia Power^a	Duke Energy^b	DTE Energy^c	Public Service Enterprise Group (PSE&G)^d	San Diego Gas & Electric (SDG&E)^e	SCE^f
Program Name	Solar Partnership Program	NC Solar DG program	DTE SolarCurrents	PSE&G Centralized Solar	SDG&E Solar Energy Project	Solar Photovoltaic Program—UOG
Start year	2012	2008	2009	2009	2009	2009
Initial Size (MW)	30	10	15	80	26	250
State	Virginia	North Carolina	Michigan	New Jersey	California	California
Asset Ownership	Utility	Utility	Utility	Utility	Utility	Utility
Energy Ownership	Utility	Utility	Utility	Utility	Utility	Utility
REC Ownership	Utility	Utility	Utility	Utility	Utility	Utility
Construction	Third party	Third party	Third party (Nova Partners)	Third party, utility	Third party	Utility
Maintenance	Third party	Utility	Utility	Utility	Third party	Utility
Host Site Type	Customer	Customer	Customer	Utility, Customer	Utility	Customer
Target Customer Segments	Commercial, industrial, educational	Commercial, educational institute, residential	Commercial, public property	Utility, commercial, public housing	Utility	Commercial
Customer Compensation Mechanism	Annual lease payments	Annual lease payment	Initial construction payment, annual easement payments	Indirect (lease payment from developer, developer contract with PSE&G)	N/A	Annual lease payments

^a SEPA 2016a; “Solar Partnership Program” 2016

^b SEPA 2016d; “North Carolina Distributed Generation Program” n.d.

^c “Solar Energy” 2016; Quackenbush, White, and Talberg 2015

^d SEPA 2016c; “Solar 4 All Program” 2016

^e SEPA 2016b; “Solar Energy Project” 2015

^f “Southern California Edison” 2010

Just as with utility-run residential programs, there are several key themes for utility-led commercial solar projects.

1. Utilities Own Energy and RECs Across All Programs

Among the profiled utility commercial programs, the administering utility retains the energy and RECs generated from the output of these utility-owned, customer-sited systems. The RECs generated by these programs are especially valuable in states with solar carve-outs such as New Jersey. In fact, PSE&G's Solar 4 All program was approved in part because the New Jersey BPU foresaw an on-going shortage of SRECs in the state and believed that additions of utility-administered solar could help ease the shortage and reduce prices.

2. Site Selection and Compensation Streams Vary Based on Host Acquisition Model

Depending on the exact design of the program, either the administering utility or installer participants could be responsible for identifying system hosts willing to participate and signing lease agreements with them. In several programs profiled (Dominion, Duke Energy, DTE Energy, SCE), the utilities identified sites that were structurally and electrically suitable for installing solar PV, as well as having willing host entities. In return for granting the utility the right to install a solar PV system on their roof, participants receive annual lease payments directly from the utilities. The amount of these lease payments may vary in the negotiation process but could be affected by the size of the roof, the amount of capacity hosted, the age and construction of the roof, the location of the site, or other factors. This is in contrast to the models used by PSE&G and SDGE, which solicited turnkey systems from developers. Under these programs, the developers would be required to identify suitable sites and secure access through a contract with the host, with the level of compensation being negotiated by the developer and host without any involvement (or funds from) the sponsoring utility. As noted above, none of the system hosts in the surveyed programs receives compensation in direct proportion to the amount of energy generated from the hosted solar system, which removes some of the financial variability that comes from compensation based on solar output.

3. Installation Widely Performed by Third Parties

As with the utility-administered residential solar programs profiled above, installation of solar systems by a contracted installer is by far the most common method of construction. Of the profiled programs, only SCE used regulated utility employees to deliver installation labor for its program's projects. Among utilities that contracted out the installation of the solar PV systems, there were slight variations in the models used. Under one arrangement employed by Dominion, Duke Energy, and DTE Energy, the utility secured lease agreements directly with system hosts before contracting a third party to design and build the solar PV system. In other cases, such as those of PSE&G and SDGE, the turnkey bids from project developers are inclusive of site selection and access, as stated above, along with system design and construction.

4. Maintenance Responsibilities Handled by Utility or by Third Party

Responsibility for maintaining the installed system varies from program to program, with some utilities choosing to deliver these services themselves while others contract them out. One important note is that the provision of maintenance services, whether by the utility directly or

through a contractor, only begins once the installer warranty has lapsed. These warranties typically span the first five years after project completion and cover regular maintenance as well as any workmanship defects. Similarly, equipment defects or failures, particularly for modules and inverters, are often covered through manufacturers' warranties.

5. Many Programs Have Been Downsized or Cancelled Outright

Due to major shifts in market conditions over time, a few of the listed programs have been scaled back from initial plans. For example, due to the maturation of the California solar market from 2008 to 2012, SCE reduced the amount of utility-owned generation (UOG) to be procured under the Solar Photovoltaic Program (SPVP) from 250 MW to 91 MW. In regulatory filings, the company cited the lower cost of PPAs offered by IPPs in other procurement mechanisms as a driving consideration for shifting away from UOG. SCE estimated that such a shift in procurement could result in a savings to ratepayers in the hundreds of millions of dollars ("Southern California Edison" 2012). Similarly, SDGE has only procured 8 MW of its total 26 MW target to date and has no plans to pursue additional projects, citing longer-than-expected permitting timelines ("San Diego Gas & Electric" 2015). Finally, the Hawaiian Electric Companies had proposed a commercial solar program in 2009, only to withdraw their application three years later amid the state's solar boom ("Withdrawal of Application" 2012).

Utility-Administered Utility-Scale Solar Programs

Many utilities today own utility-scale solar power projects to diversify their existing generation portfolios, meet RPS requirements, provide return on investment, or influence the siting of solar energy capacity on the electric grid. Investment in solar generation projects has become more attractive for utilities due to the 30% federal ITC for solar systems. Utility-scale solar business models have been well established in the utility industry for many years and have evolved over time.

- **Project development, construction and O&M:** Utilities can use many combinations of strategies to prepare, build, and maintain utility-scale solar projects. The development of these projects (a phase that may include selecting and securing site access, PPA negotiations, permitting, and interconnection agreements) can be completed by the utility itself, a developer, or a combined developer-EPC. After this phase, either an EPC or developer-EPC will design and construct the actual solar facility. After completion, either the utility, EPC, or developer-EPC may be selected to deliver O&M services (Mendelsohn and Kreycik 2012).
- **Asset, energy, and REC ownership:** Under the three financing models discussed below, ownership of the physical asset, energy and RECs will typically all be held by a single party, either the regulated utility or the unregulated project development subsidiary. One major variation in this model occurs when the utility subsidiary signs a PPA with an offtaker such as an unaffiliated utility or corporate buyer. In such a case, ownership of the energy (and RECs, if applicable) will be transferred to that offtaker via the PPA.
- **Financing.** Utilities can invest in solar assets through direct finance, developer subsidiaries or affiliates, or utility prepay.

- *Direct financing*: Utilities can directly finance, own, and operate solar energy projects. Utilities are considered creditworthy entities that can avail capital at a favorable interest rate, which makes them well-suited to make such investments. If directly owned, investments are recovered through the utility's base rates and are allowed to earn the company's weighted average cost of capital (Mendelsohn and Kreycik 2012). An example of direct financing is Florida Power & Light Company's investment in 110 MW of solar power in DeSoto, Charlotte, and Manatee in 2009. In early 2015, this commitment was extended with a planned investment in an additional 225 MW in solar power (Walton 2015).
- *Unregulated developer subsidiaries*: Utilities can invest through developer subsidiaries or affiliates, which are held by utility parent companies. By their nature, unregulated subsidiaries do not need project approval from state utility regulators and are not subject to tax normalization requirements (as explained in Section 4), though they are also unable to recover costs through regulated electricity rates, potentially increasing risk. For example, the utility parent companies (Dominion Resources, Duke Energy, and NextEra Energy) hold both regulated subsidiaries (Dominion Virginia Power; Duke Energy Progress, Duke Energy Carolinas, Duke Energy Indiana; and Florida Power & Light Company) and unregulated development arms (Dominion Generation, Duke Energy Generation Services, and NextEra Energy Resources). For example, Duke Energy Generation Services financed the construction of a 14-MW solar PV facility in Texas ("Duke Energy" 2010). Similarly, another parent company, MidAmerican Energy Holdings (the parent of the regulated Iowa-based utility MidAmerican Energy Company) used the unregulated MidAmerican Renewables, LLC, to purchase the entirety of the 550-MW Topaz Solar Farm and a 49% share of the 290-MW Agua Caliente project, both located in California (Mendelsohn and Kreycik 2012).
- *Utility prepay (hybrid financing)*: This model takes advantage of utility's ability to borrow low-cost capital to make a bulk prepayment for electricity to be delivered over the project life. After this prepayment, the utility is entitled to energy from the project at no cost, though it must make regular debt repayments on the borrowed lump sum (Delony 2008). It has been mostly used by municipal utilities, which will typically set up the solar project as held by a for-profit LLC because the utilities themselves have no tax liabilities and are therefore unable to access value of the ITC (Mendelsohn and Kreycik 2012). This method may be a suitable way to finance utility-scale solar; however, the model is more commonly implemented in utility-owned wind energy projects (Feldman 2011).

Table A-3 summarizes the possible combinations of responsible parties for specific phases of utility-administered utility-scale PV project execution.

Table A-3. Comparison of Utility-Administered Utility-Scale Programs

	Build and Own	Unregulated Subsidiary	Utility Prepay
Development	Utility, developer, or developer-EPC		
Construction	EPC or developer-EPC		
Maintenance	Utility, EPC, or developer-EPC		
Finance	Utility	Utility subsidiary financed	Utility—Low cost capital
Asset Ownership	Utility	Utility subsidiary	Utility
Energy Ownership	Utility	Utility subsidiary or other offtaker	Utility
REC ownership	Utility	Utility subsidiary or other offtaker	Utility

Utilities have also used other, purely financial means to invest in solar companies or funds, rather than individual projects. Such investments are made by the utility holding or parent company rather than the regulated divisions, and they can be made in the residential, commercial or utility-scale segments. Examples of these types of investments have been equity investments from Duke Energy, Edison International, and NRG in Clean Power Finance; acquisition of solar companies by Duke Energy, Edison International and NextEra Energy; and tax equity financing for SolarCity installations from PG&E Corporation (Mulherkar 2015; “PG&E Corporation” 2010).

Detailed Profiles for Select Programs

Residential Sector

Tucson Electric Power Residential Solar Program

The TEP Residential Solar Program is a 3.5-MW DG utility-owned residential solar rooftop program that was initiated in mid-2014. The ACC authorized TEP to make the program available to up to 500 residential customers in 2015 (“Residential Solar Program” 2016). The minimum capacity considered under the program is 3 kW (“Residential Solar Program” 2016). Under this program, TEP owns, operates, and maintains the PV system. TEP chooses solar installers through a competitive bidding process. The consumers are charged an initial \$250 in processing fees (AZCC 2014b). Consumers who take part in this program have a 25-year locked monthly electricity fee, based on their average annual historic energy usage. It is estimated that an average customer spends \$90–\$100 on electricity per month, thus the electricity rate would be fixed at \$99 per month for the next 25 years (AZCC 2014b). If the electric usage increases or falls below 15% of the current consumption, their fixed rate would be reset to match their energy consumption. The utility claims this program prevents unfair cost-shifting to other customers. The installed cost under this program is estimated at \$2.85/W–\$3.00/W (AZCC 2014b). The program does not involve any net metering, and TEP claims the RECs generated by these systems to fulfill its renewable energy compliance requirements. TEP targets customers in areas that are most beneficial for utility operations and aims to include customers with financial constraints into the program.

Arizona Public Service Sun Distributed Generation

The APS Sun DG program targets solar electric generation of 20 MW with 3,000 4-kW to 8- kW solar system installations. APS will competitively bid for installers while giving a preference to local installers for this program. Under this program APS owns and operates the solar systems while they are located on rooftops of their residential customers. The customers in turn will receive a monthly credit on their bill for \$30 through the life of the 20-year program. The customer does not bear any upfront costs. The program does not involve any net-metering (“Solar Partner Program” 2015). The RECs are owned by the utility and used to fulfill its compliance requirements. The company also focuses on lower credit worth customers who do not qualify for leases. APS is also targeting homeowners with west-facing roofs to better match overall system peak loads while including a limited number of south-facing roofs (“Solar Partner Program” 2015). APS has estimated installed cost of \$2.85/W to \$3.50/W for its program (APS 2014).

CPS Energy-Solar Host

CPS Energy, San Antonio’s municipal utility, rolled out an innovative model to prevent cost shifting from solar to non-solar users on the grid. The program targets 10 MW and is applicable to the residential and commercial sector, with 5 MW targeted for residential and 5 MW for commercial. Similar to APS, CPS Energy operates solar panels installed on customers’ roofs by third-party installers, without any upfront costs. It will pay customers \$0.03 per kWh for the electricity the solar generates, thus giving customers a bill credit based on the amount of energy produced. The average residential rate for electricity is currently \$0.10 per kWh (“SolarHost San Antonio” 2015). The electricity flows directly to the grid, and not to the house, so there is no net metering. CPS Energy has engaged PowerFin Partners in a 20-year PPA for this program (Trabish 2015a). PowerFin Partners owns the panels and power, and it is responsible for maintenance and insurance. This power is bought by CPS Energy at a competitive PPA rate. The RECs from this renewable power will be attributed to CPS Energy. The utility will target specific areas to address high penetration on circuits or other loading issues.

ConEdison Solutions

ConEdison Solutions, the unregulated subsidiary of the New York investor-owned utility Consolidated Edison, initiated a residential rooftop solar leasing program earlier this year. ConEdison's regulated utility division is barred from owning distributed resources as a consequence of the restructuring of New York’s electricity market. In this program, ConEdison Solutions will own the leased systems and offer customers 20-year leases without any upfront costs. It will collect monthly lease payments from homeowners that are below the retail rate of the customer currently (Trabish 2015b). ConEdison Solutions will finance, install and own the solar facilities. SunPower will provide a 20-year limited warranty and production guarantee for the solar modules (“ConEdison Solutions” 2015).

Georgia Power—Solar Customer Assistance Program

The Solar Power Free Market Financing Act (2015) prevents utility interference in the installation of solar projects in Georgia, authorizes third-party ownership of customer-sited solar

PV systems, and allows utility companies and their affiliates to finance onsite solar projects for customers (“HB 57” 2015). With this, Georgia Power launched its rooftop solar business through an unregulated subsidiary Georgia Power Energy Services. Georgia Power, the regulated subsidiary, also recently announced a web portal that connects customers to solar (Pyper 2015). The portal advises customers on their suitability to adopt solar energy and their options after customers complete a basic analysis of their demand and potential. The customers can then choose from different solar installers or the utility subsidiary itself. According to experts, this model has the potential to lower customer acquisition costs for installers (Pyper 2015).

Commercial Sector

Dominion Solar Partnership Program

Pursuant to Chapter 771 of the 2011 Virginia Acts of Assembly (House Bill 1686) the Company obtained a CPCN from the SCC in November 2012 (Case No. PUE-2011-00117) for the Solar Partnership Program to install up to 30 MW of solar PV DG by 2015 in its Virginia service territory. A cost cap imposed as a condition of the SCC's approval will allow for the installation of a total of approximately 16 MW as part of the program. Installations are being placed on existing structures (e.g., customers' leased rooftops) and previously developed properties (e.g., ground-mounted solar arrays) to assess the potential impacts and benefits on its distribution system. A total of 1.175 MW were completed in 2014, 795 kW were completed in 2015, 3.3 MW were under construction at the end of 2015, and plans are to develop another 9 MW by the end of 2016.

Duke North Carolina Solar Distributed Generation Program

The Duke Energy North Carolina Solar DG program was one of the first utility-owned DG programs in the United States. It started in 2008 and targeted 10 MW. Of the 10 MW, 80%–90% of the energy is to be generated from large-scale facilities like commercial or industrial buildings with system sizes between 500kW and 3 MW; 10% of the energy is to be generated from medium-scale facilities like schools, office buildings, and multi-family rooftops with system sizes between 15 kW and 500 kW; and 10% of the energy is to be generated from small-scale facilities like residential rooftops with a system sizes between 1.5 kW and 5 kW (SEPA 2016d). The program comprises 25 sites throughout North Carolina, each selected based on the landowner's interest in solar energy, the site's proximity to the electrical grid, and its solar potential (“North Carolina Distributed Generation Program”).

Duke Energy owns and maintains the solar panels, and receives electricity from the solar energy generated on the customer site. Site owners receive annual fees for use of their roof or land and did not have to make any initial investment. Solar module and installation providers were selected in an open bid system, while Duke Energy plans to maintain the PV systems for the life of the lease beyond the installer warranty (“North Carolina Distributed Generation Program”). The utility claims that over the life of the program the cost to the average residential customer in North Carolina will not exceed 8 cents per month, commercial costs will not exceed 42 cents per month, and industrial costs will not exceed \$4.25 per month (“North Carolina Distributed Generation Program”).

DTE SolarCurrents Program

The DTE Energy SolarCurrents program was initiated in 2009 and targeted 15 MW with system sizes of 100 kW to 500 kW (“DTE Utility-Owned” 2012). Currently, 20 projects totaling 8.19 MW of solar PV capacity are complete. DTE Energy owns and maintains the DG solar plants. It contracted Nova Consultants, Inc. to engineer, procure, and construct the facilities, which are located on the large rooftops, are ground mounted, or located on DTE sites. The customers get easement payments in the form of an annual credit on their energy bill along with a one-time upfront construction payment. DTE uses a standard site easement agreement in this process (“DTE Utility-Owned” 2012). In addition, DTE gives each customer an on-site educational kiosk to increase general awareness of solar energy. DTE owns the RECs for the renewable energy generated under this program.

Southern California Edison Solar Photovoltaic Program

Southern California Edison (SCE) initiated the Solar Photovoltaic Program in 2009. The program has two components: UOG and IPP-owned generation (“Investor-Owned Utility Solar” 2016). For the UOG, SCE would install, own, operate, and maintain distributed solar projects on commercial rooftops with a system size range of 1 MW to 2 MW. Their cost target was \$3.5/W with a 10% contingency (“Southern California Edison” 2010). For the IPP-owned generation, 250-MW systems (50 MW annually) were installed, operated, and maintained by IPPs. The IPPs were chosen annually through a competitive bidding process, which was capped at utility-owned Solar PV Program’s LCOE (\$260/MWh) (“Addressing a Solar Photovoltaic Program” 2016). For IPP-developed projects, SCE identified locations where distributed solar PV would be most desirable, thereby optimizing the locational value of the project sites. The IPP is responsible for securing a lease for the rooftop of the host solar site under consideration. And, the IPPs are required to complete due diligence and processes, such as roof leasing, the interconnection process, and permitting. SCE buys all products (energy, RECs, capacity, and resource adequacy) from the IPP (“Addressing a Solar Photovoltaic Program” 2016). SCE makes a monthly payment based on metered amounts, and these payments are adjusted by SCE’s Time-of-Delivery Periods and Energy Payment Allocation Factors. Under this program, customers cannot participate in the California Solar Initiative program or net energy metering program.

Appendix B: Survey Instrument

Figure B-1 shows the web-based survey questions as they were displayed to participants. Additional pages requesting information about areas of business within their selected states were presented but are not shown here for the sake of brevity. In addition, a space was provided on each page for respondents to provide any additional information they felt necessary to provide context to their responses.

Figure B-1. Web-based Survey Responses.

General Information

Please provide the following contact information:

Respondent Name	<input type="text"/>
Respondent Job Title	<input type="text"/>
Respondent Phone Number	<input type="text"/>
Respondent Email Address	<input type="text"/>

Please provide the following information about your company:

Company Name	<input type="text"/>
Address	<input type="text"/>
City	<input type="text"/>
State	<input type="text"/>

Please indicate the state(s) in which your company does business:

- Georgia
 - Maryland
 - North Carolina
 - Virginia
 - Washington, D.C.
-

Please indicate the types of installations your company has completed to date:

- Residential
- Commercial & Industrial (< 250 kW)
- Commercial & Industrial (> 250 kW)
- Utility-Scale

Installation Information

Please indicate the number of PV systems that your company completed in your selected states and market segments in the first half of 2015 (H1 2015):

	Residential	Commercial & Industrial (< 250 kW)	Commercial & Industrial (> 250 kW)	Utility-Scale
Georgia	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Maryland	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
North Carolina	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Virginia	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Washington, D.C.	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Total	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>

Please indicate the total capacity (in MW DC) of PV systems that your company completed in your selected states and market segments in the first half of 2015 (H1 2015):

	Residential	Commercial & Industrial (< 250 kW)	Commercial & Industrial (> 250 kW)	Utility-Scale
Georgia	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Maryland	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
North Carolina	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Virginia	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Washington, D.C.	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Total	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>

Average System and Component Cost

Please indicate the average, pre-incentive system cost (in \$/W DC) for the average-sized solar PV system completed in H1 2015 in select market segments:

	Residential (your average system size: 0 kW)	Commercial & Industrial (< 250 kW) (your average system size: 0 kW)	Commercial & Industrial (> 250 kW) (your average system size: 0 kW)	Utility-Scale (your average system size: 0 kW)
Total Average Cost	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>

Please indicate the share (as a percentage) of average pre-incentive costs attributable to the following categories:

	Residential	Commercial & Industrial (< 250 kW)	Commercial & Industrial (> 250 kW)	Utility-Scale
Module	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Inverter	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
Racking and Other Hardware	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
All non-hardware (soft) costs associated with system installation (includes customer acquisition, system design, permitting, interconnection application, incentive preparation and filing, installation labor, arranging financing, etc. - please do not include O&M and ongoing insurance expenses)	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>

Customer Acquisition and System Design Costs

For the following questions, please record only those costs incurred in states you selected at the beginning of the survey (Georgia, Maryland, North Carolina, Virginia, Washington, D.C.).

What was the total cost of customer acquisition activities in H1 2015?
(including marketing/advertising, sales calls, site visits, travel time to and from the site, contract negotiation with system host/owner, and bid/pro-forma preparation, but excluding system design)

Note: for utility-scale projects, please indicate costs associated with identifying potential customers, responding to RFPs, negotiating and signing PPA or other off-take agreement.

What was the total cost of system design in H1 2015?
(includes all system design activities both before and after the contract is signed)

How many bids did you prepare in H1 2015, or prior, for residential systems with a planned installation date in H1 2015?
(number of individual bids that could lead to a contract, including multiple bids prepared for the same customer)

In H1 2015, what percentage of projects with executed contracts were ultimately canceled?

Please indicate which, if any, of the following customer acquisition strategies your company uses:

- Direct mail
 - Email
 - Telephone
 - Door-to-door sales
 - Marketing programs and partnerships (e.g. SolarCity and Home Depot)
 - Lead qualification and generation programs (e.g. One Block off the Grid)
 - Referral programs
 - Consumer-awareness campaigns
-

Please indicate which, if any, of the following system design strategies your company uses:

- Remote site assessment (e.g. Google Maps)
- Standardized system design templates

Site Acquisition

Please indicate your company's total expenditures for site acquisition in H1 2015 in the selected states where you do business (Georgia, Maryland, North Carolina, Virginia, Washington, D.C.)

(including identifying potential sites, site assessment, and negotiation of site control via lease or purchase; excluding land lease or purchase payments and any site preparation or other site modification/pre-construction activities):

Permitting, Interconnection, and Incentive Administration Costs

For the following questions, please restrict your responses to operations in those states which you selected at the beginning of the survey (Georgia, Maryland, North Carolina, Virginia, Washington, D.C.).

Please indicate the average number of labor hours spent to complete each of the following tasks for a solar system of the average size (kW) as indicated in the PV deployment section:

Preparing a permit package (determining requirements, travel time, drawings, structural calcs, zoning, etc.)	<input type="text"/>
Submitting a permit package (travel to and from permit office, wait time)	<input type="text"/>
Completing the permitting inspection (including paperwork, travel to and from site, wait time for inspector, physical inspection)	<input type="text"/>
Completing the interconnection process (paperwork, travel to and from site, wait time for utility, physical interconnection)	<input type="text"/>
Applying for and receiving all state and federal incentives (determining eligibility, paperwork, site visits, inspection)	<input type="text"/>

Please indicate which, if any, of the permitting, interconnection and incentive administration strategies your company uses:

- Online database of permitting requirements by jurisdiction
 - Online permit application submittal
-

Please indicate the share of PV systems completed in H1 2015 that had the following process features (as %):

Local jurisdiction permitting fees of \$250/system or less	<input type="text"/>
Local jurisdiction permitting fees of \$100/system or less	<input type="text"/>
Expedited utility interconnection process for systems that pass basic technical screens	<input type="text"/>

Financing Costs

Please indicate the share of installations (as a % of all installations) delivered with the following financing options in the selected states where you do business (Georgia, Maryland, North Carolina, Virginia, Washington, D.C.):

Third-party ownership with lease	<input type="text"/>
Third-party ownership with PPA	<input type="text"/>
Secured loan via solar financier	<input type="text"/>
Secured loan via commercial bank	<input type="text"/>
Unsecured loan via solar financier	<input type="text"/>
Unsecured loan via commercial bank	<input type="text"/>
Property-Assessed Clean Energy (PACE) loan	<input type="text"/>
Second mortgage	<input type="text"/>
Power Saver loan via FHA	<input type="text"/>
Direct cash purchase	<input type="text"/>
Other (please indicate)	<input type="text"/>

Operations & Maintenance and Insurance Costs

For the following questions, please restrict your responses to operations in those states which you selected at the beginning of the survey (Georgia, Maryland, North Carolina, Virginia, Washington, D.C.).

Please report your total expenditures in the following categories in H1 2015:

Operations and maintenance costs (including regular inspections and upkeep, repairs and replacement of equipment, etc.)	<input type="text"/>
PV system insurance costs	<input type="text"/>

Please indicate which, if any, of the following practices your company uses:

- Real-time system output monitoring to track PV system performance
- Inverter replacement considered a standard O&M expense over the life of a PV installation
- Micro-inverters or other module-level power electronics

How does your company deliver operations and maintenance services? Please check all that apply:

- Contracts with solar installer or EPC which built the system
- Provides operations and maintenance services in-house
- Outsources operations and maintenance services to a third-party provider
- Does not provide operations and maintenance services

Please indicate the types of insurance policies your company carries:

- General liability insurance
- Property risk insurance
- Professional liability Insurance
- Inland marine insurance
- Business interruption insurance
- Environmental risk insurance
- Workman's compensation insurance
- Warranty insurance
- Contractor bonding