



System Reliability Procurement Distributed Generation Pilot Evaluation Report

FINAL REPORT

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Prepared for:

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Executive Summary

The Rhode Island Office of Energy Resources (OER) contracted with Cadmus to evaluate the effectiveness of its System Reliability Procurement Solar Distributed Generation (SRP DG) pilot. The pilot offered incentives to customers to site and install solar photovoltaic (PV) systems optimized for grid support, rather than overall annual generation, to support a regional program to reduce peak load (i.e., summer afternoons) on constrained feeders. While most PV arrays, when possible, are oriented southward to maximize annual generation, the pilot sought to encourage, through incentives, more customers to install systems that face westward, aligning peak generation more closely with peak load during summer afternoons, when the sun is in the western sky. The SRP DG pilot included installation of a 250 kW single-axis tracking PV system in Little Compton and a Solarize program to encourage residential installations in Tiverton and Little Compton, Rhode Island, to reduce peak load on National Grid feeders Tiverton 33F3 and 33F4.

About the SRP DG Pilot

What. A pilot program by OER and National Grid to use distributed generation to address system capacity constraints, in lieu of infrastructure upgrades like constructing new substation feeders. If successful, the overall SRP will delay or eliminate the need for an estimated \$2.9M in system upgrades by National Grid

Who. This study focuses on the 57 residential and 1 commercial scale customers who installed solar PV systems (total of 649 kW installed capacity)

Where. Tiverton and Little Compton, RI (National Grid feeders 33F3 and 33F4)

When. Participating systems were completed between late 2015 and summer 2017 and the study analyzed performance of these systems for summer peak periods in 2016 and 2017

Cadmus evaluated the impacts of the SRP DG pilot and conducted a process evaluation to determine how stakeholders perceived the program. The process evaluation included a series of stakeholder interviews and residential customer surveys intended to collect information about the program design and implementation process from a variety of viewpoints. For the impact evaluation, Cadmus collected PV system performance data from existing on-site data acquisition systems and concurrent loading data supplied by National Grid for the feeders included in the study. As a part of our analysis, we determined actual peak load reduction and verified the results of the pilot's load reduction goals.

Key Findings

After reviewing the results of the SRP DG pilot analysis, Cadmus identified several key findings from the process and impact evaluations:

Key Finding 1: Orienting PV arrays more westward increased coincident peak output.

For systems included in this study, arrays oriented westward generated 23% to 46% more energy during coincident demand periods (defined as the top 10% most heavily loaded hours on the studied feeders) than systems oriented toward the south, with coincident peak output increasing the closer the system was oriented to true west. Throughout 2017, the overall impact on annual generation was as expected, with west-facing systems (oriented greater than 247.5 degrees) producing 10% less energy per unit installed capacity than south-facing systems (oriented less than 202.5 degrees). This agrees with the Peregrine Energy RI SRP pilot report from June 2014 which stated that a southwest-facing system (oriented to 220 degrees) would produce 5% less energy annually than a system oriented due south at 180 degrees. However, the results also show that west-facing systems generated more power per unit of installed capacity during coincident peak loading hours than systems oriented with a southern azimuth. This finding confirms that western-facing PV systems outperform other orientations when attempting to reduce summer afternoon peak loads.

Key Finding 2: In 2017, for every direct current kilowatt (kW-DC) of rooftop solar PV installed, coincident peak decreased by 0.21 alternating current kilowatt (kW-AC) for south-facing systems and 0.28 kW-AC for west-facing systems. The tracking PV system generated 0.32 kW-AC per kW-DC in coincident periods.

Overall for 2017, the residential fleet reduced coincident demand by 0.21, 0.26, and 0.28 kW for every nameplate kilowatt of PV installed oriented toward the south, southwest, and west, respectively. The solar field project, which tracks the sun, provided 0.32 kW of peak demand benefits per nameplate kilowatt. While there may be some variability in these results from one year to the next, largely based on weather conditions, these values can serve as reasonable planning values for considering the likely peak demand impacts of future PV installations under conditions similar to those of the SRP DG pilot.

Key Finding 3: Though PV reduced overall coincident demand, maximum system peaks occurred late in the day compared to PV system output.

The 2016 and 2017 maximum peak load on the studied feeders occurred between 5 p.m. and 7 p.m., a period during which even west-facing PV arrays produce little benefit. However, when considering the top 10% hours with the highest loading, half of those hours occurred between 3 p.m. and 8 p.m., a broader period during which west-facing PV systems made a greater contribution to peak reduction.

Key Finding 4: The SRP incentive promoted the adoption of west-facing PV while keeping the cost of reducing peak demand equivalent across orientations.

The cost of coincident demand reduction for roof-mounted systems, as determined by the incentive issued by the SRP DG pilot plus the statewide solar incentive from Commerce Rhode Island's Renewable Energy Fund (REF), was comparable across all orientations at about \$5,200 per kilowatt. The cost of coincident demand reduction from the ground-mounted single-axis system was \$2,310 per kilowatt.

Key Finding 5: Calculating and communicating incentive values was a challenge.

The incentive calculations proved challenging for the Solarize installer to use in practice and resulted in some miscommunication and miscalculation of incentives. In particular, the existing spreadsheet tool used for incentive calculations proved difficult to use, and the overlapping azimuth bins (e.g., 180-190, 190-200) added uncertainty to the process. Also, installers initially found it difficult to determine the shading impacts on the incentive and avoid the high shading screen threshold (90%). While the shading screen was relaxed later in the Solarize process, other programs that consider a similar incentive structure may want to devote extra time in the early stages to ensure that installer-partners understand the necessary calculation methods for determining incentives, or consider options for streamlining the incentive calculation.

Key Finding 6: The additional incentive increased overall solar adoption.

In order to be economically attractive for most customers, PV installations in Rhode Island typically require an incentive. For many customers, the incentives available from Commerce Rhode Island’s REF are sufficient to make a system economically viable. However, the program requires that systems generate 80% of optimal annual output to be eligible for incentives and many of the west-facing systems included in this study fall short of that threshold and cannot normally receive REF incentives. By waiving the REF’s 80% total solar resource fraction (TSRF) requirement for pilot participants, OER gave customers with west-facing roofs a financially feasible path to install solar. Additionally, by offering a specific incentive for west-facing systems, OER gave customers with these roofs access to an incentive that made installing west-facing PV economically competitive with south-facing systems. This effectively expanded the number of homes able to install solar. That, combined with an effective sales model by the installer, may have been a contributing factor in above-average conversion rates from leads to signed contracts in the Tiverton and Little Compton Solarize campaigns.

Key Finding 7: There were many challenges with residential production monitoring.

As part of the installation process for the Solarize sites, Sol Power installed Solar Log data acquisition systems. The purpose of these metering systems was to provide hourly generation data for use during this evaluation and related research. In practice, Sol Power reported significant difficulty with installing, configuring, and receiving data from these meters. Challenges included poor cellular/satellite communications reliability, meters functioning improperly, and missing or incomplete data. Overall, as part of this study, only 27 (out of 57) sites contributed useful data for analyzing the 2017 summer period. For the 2016 summer period, only 19 sites had useable data. Despite efforts by Sol Power, Cadmus, OER, and others, less than half of residential sites are reliably reporting hourly generation data via the Solar Log metering system. In designing future programs, it is important to ensure that those developing the program carefully consider metering and data acquisition in the program design. For example, ensuring that technicians installing the metering equipment have sufficient training and technical support to handle challenges like poor reception or communications errors should be integral to program implementation, as this is outside the normal day to day function of most PV installation personnel. It may also be useful to ensure that installers are properly motivated to prioritize data collection by integrating metering results into the installer’s ability to receive incentives, while at the same time providing sufficient incentive for installers to spend the time and resources necessary to

install, maintain, and troubleshoot data acquisition systems. Alternatively, future studies should include data acquisition specialists who are trained and equipped to address these issues, leaving PV installers to focus on their core competency areas (i.e., installing PV systems). While the installer of the pilot systems was very helpful in working to identify and resolve issues, they had little experience with the chosen data acquisition systems and appeared to have little incentive to fully support the data collection effort once the PV systems were installed and operating. This presented a major barrier to data collection for this study.

Key Finding 8: Assuming similar incentives, a total spending budget of \$3.0 to \$3.1 million would achieve a 5% reduction in peak load utilizing rooftop-mounted systems.

To achieve an average 5% reduction in coincident load (0.63 MW), using the same incentives provided during the pilot, would require installing approximately 2.0 MW of west-facing or 2.8 MW of south-facing, with a required total incentive (both SRP and REF) of \$3.0 or \$3.1, respectively. This added capacity, if deployed, would provide substantial relief to local distribution system loading. Though not the focus of this study, an energy storage system (or group of distributed systems) capable of supplying 0.63 MW for four hours (i.e., a total capacity of approximately 2.5MWh) could also achieve a 5% demand reduction target and could also be an attractive alternative to other types of equipment upgrades and merit further investigation.

Key Finding 9: The 649 kW DG pilot capacity did not achieve the pilot’s 250 kW peak load reduction target.

After extrapolating the total system production for all installed systems, the total output during max loading hour of 2017 is estimated at 182 kW, which represents a 1.18% peak load reduction. The capacity factors observed in this analysis were significantly lower than the estimates in the Peregrine study. For a west-facing system, Peregrine had assumed a 55% capacity factor during max loading hour, while Cadmus observed a capacity factor of 34% for the same system. We found similar results when analyzing across coincident hours: in 2017, with all systems operational, the mean total power output during the top 10% of hours was 174 kW.

Introduction

In 2006, National Grid was mandated to pursue “all cost-effective” energy efficiency resources before acquisition of additional electrical supply. Part of this mandate required National Grid to annually develop a System Reliability Procurement (SRP) plan that considers a wide range of customer- and utility-sited energy resources, including cost-effective energy efficiency, distributed generation, and demand response measures. These measures are collectively known as non-wires alternatives (NWA) and may help to reduce peak loads on the electrical grid. National Grid must assess whether these NWA can be deployed to avoid the use of expensive utility power plants and defer the investment of capital on infrastructure upgrades.

Figure 1. Timeline of SRP DG Pilot

Date	Event
February 2012	Rhode Island Public Utilities Commission approves System Reliability Procurement 6-year Load Curtailment Pilot for Tiverton and Little Compton (“DemandLink”) in Docket 4296
June 2014	Peregrine Energy Group completes report for OER and National Grid on “Solar PV for Distribution Grid Support” outlining the potential for a solar PV pilot to complement DemandLink
January 2015	Solarize Tiverton and Solarize Little Compton campaigns launch
February 2015	OER issues RFP for “Solar PV for Distribution Grid Support” for larger-scale PV system(s) in SRP pilot area
April 2015	“Solar PV for Distribution Grid Support” RFP awarded for single-axis tracking system
June 2015	Solarize Tiverton and Little Compton conclude
October 2015	Evaluation for the SRP DG pilot begins
Summer 2016	First full summer of PV production data (only Solarize installations)
July 2017	Single-axis tracker system begins operation
Summer 2017	Second full summer of PV production (Solarize installations and single-axis tracker)
May 2018	Evaluation for SRP DG pilot concludes

One of the first initiatives developed through the SRP plan was a pilot program known as DemandLink, which launched in 2012. National Grid implemented the pilot in the towns of Tiverton and Little Compton. The goal of the pilot was to manage local distribution capacity requirements during peak periods and defer capital investment in a new feeder at the local substation by reducing peak annual load through energy efficiency measures and a demand response program from 2014 until the end of 2017. The estimated cost to replace the substation was \$2.9 million in 2014.¹

While the annual SRP reports suggested numerous opportunities for energy efficiency and demand response applications, they did not discuss assessing the potential of distributed renewable energy

¹ National Grid. *2017 System Reliability Procurement Report*. 2016. Available online: [http://www.ripuc.org/eventsactions/docket/4655-NGrid-SRP2017\(10-17-16\).pdf](http://www.ripuc.org/eventsactions/docket/4655-NGrid-SRP2017(10-17-16).pdf)

systems for inclusion into the system reliability portfolio. OER created the SRP DG pilot project to address the lack of renewable energy initiatives proposed in the SRP plan. As a first step, OER—in partnership with National Grid—commissioned a study from Peregrine Energy Group, Inc., on solar PV for distributed generation (Peregrine study).²

The study included these goals:

- Assess solar deployment options and develop a proposed configuration for a portfolio of distributed generation resources to meet 250 kW of summer peak load reduction in the SRP pilot area of Tiverton and Little Compton
- Recommend an implementation strategy to solicit participation in the pilot and procure the distributed generation resources

The recommendations from the study resulted in the development of the Solarize Tiverton and Little Compton campaigns and the Grid Support Solar Field project. Solarize is a targeted marketing, education, and outreach campaign aimed at increasing solar PV adoption in a community through the benefits of economies of scale. The Solarize program was administered by OER, Commerce Rhode Island, and a nonprofit marketing company, SmartPower (collectively, program administrators). Project costs vary on a dollar-per-watt basis, as outlined in Solarize pricing tiers, and costs decline as more customers participate. The program administrators and both towns competitively selected a PV installer, Sol Power, as the solar installer for Tiverton and Little Compton. Together, the program team’s efforts led to the installation of 32 systems in Little Compton and 25 in Tiverton during the campaign, which ran from January 2015 to June 2015. Table 1 summarizes the total capacity of these contracts.

Table 1. Total Installed Solar Capacity for SRP DG Pilot

System Type	Number of Sites	Capacity (kW DC)
Little Compton Solarize	32	211.92
Tiverton Solarize	25	187.81
Grid Support Solar Field – single-axis tracking system	1	249.9
Total Installed	58	649.63

OER designed the Grid Support Solar Field project as a small- to medium-scale ground-mounted solar system that would bolster the total installed capacity of the SRP DG pilot. OER solicited competitive bids for the project and awarded it to Econox Renewables, which proposed installing a 250 kW ground-mounted tracking system.³

² Peregrine Energy Group, Inc. *Solar PV for Distribution Grid Support: The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project*. 2014. Available online: <http://www.energy.ri.gov/electric-gas/future-grid/oer-system-reliability-solar.php>

³ The OER solicitation for bids, “Solar PV for Distribution Grid Support,” is available online: <http://www.purchasing.ri.gov/bidding/ContinuousRecruitment.aspx> - see CR-38.

Process Evaluation

The objective of the process evaluation of the SRP DG pilot was to gain a full understanding of the solar initiatives' processes, evaluate the initiatives' effectiveness and efficiency, and compare the process and results to similar initiatives in the state and region. This evaluation encompassed the entire pilot project, including the Solarize campaign and subsequent residential installations, the Grid Support Solar Field procurement and development, and the overall pilot design and deployment, including incentive structure and market response.

Approach

Cadmus developed and deployed a survey for Tiverton and Little Compton participants and used in-depth stakeholder interviews to gather the initial qualitative and quantitative results needed to achieve the process evaluation objectives. The interviews and surveys explored the following topics:

- Project roles and responsibilities
- Project logic, strategy, and delivery
- Marketing and outreach plans and strategies
- Target audiences for the various project components
- Barriers to project participation and approaches to overcome those barriers
- Project successes and challenges
- Areas for improvement, particularly marketing

Cadmus tailored its evaluation methods to specific stakeholders. Table 2 identifies the stakeholders we contacted and the methods we used to interface with them. See Appendix A for the results of the survey.

Table 2. SRP DG Pilot Stakeholders

Stakeholder	Evaluation Approach	Participants
OER – SRP DG pilot staff	Phone interview (1)	Danny Musher, OER
OER – Solarize staff	Phone interview (1)	Shauna Beland, OER
National Grid SRP staff	Written response (1)	Ryan Constable and Ian Springsteel, National Grid
Grid Support Solar Field solar developers (non-bidding)	Phone interview (2)	Julian Dash, Clean Economy Development Palmer Moore, Nexamp
National Grid SRP DG pilot staff	Written response (1)	Lindsay Foley, National Grid
Town Administrators	Phone interview (1)	Robert Mushen, Little Compton
SmartPower staff	Phone interview (1)	Matt Ray, formerly of SmartPower
Grid Support Solar Field solar developer (selected)	Phone interview (1)	Scott Milnes, Econox Renewables
Solarize installer	Phone interview (1)	Eric Beecher, Sol Power
Solarize customers	Online survey (56 Solarize participants)	Based on list of Solarize participants provided by OER

Detailed Findings

Cadmus designed the stakeholder interviews to investigate specific aspects of the SRP DG pilot. All interviews adhered to established guidelines. For each of the following sections, we wanted to understand stakeholder’s goals, purpose, success, and challenges:

- The overall pilot program through interviews with OER and National Grid SRP representatives
- The Solarize marketing campaign through interviews with OER, SmartPower, Sol Power, and municipal representatives
- The Solarize Installation through interviews with OER and Sol Power
- Grid Support Solar Field through interviews with OER, Econox, and non-bidder solar developers Nexamp and Clean Economy Development

Not all stakeholders experienced every part of the pilot. Therefore, we synthesized relevant responses based on the interview guidelines to provide a more cohesive narrative.

Overall Pilot Experience

Cadmus interviewed Danny Musher (OER) and received a written response from National Grid staff about their experiences with the SRP DG pilot.

Objectives

The initial focus of the National Grid’s SRP report was to reduce demand by using energy efficiency and demand response measures, but OER wanted to include a distributed generation component to study the potential of solar in reducing peak demand on the distribution system. OER used 35% of the auction

proceeds from the 2011 Regional Greenhouse Gas Initiative funds to implement the SRP DG pilot in coordination with National Grid's SRP process.

Overall, OER's goal for the pilot was to build long-term confidence in distributed generation as a viable strategy for demand reduction, based on quantifiable distribution system cost-deferral benefits.

National Grid reported one primary goal for the pilot: to quantify (in terms of kilowatt and cost per kilowatt) the potential of distributed solar power to achieve a targeted peak load reduction—specifically, whether the target 250 kW of peak reduction can be achieved with approximately 520 kW of installed solar capacity. National Grid also identified these additional goals:

- Evaluate the value of azimuth and tilt specifications
- Understand which interval data are necessary for the verification analysis
- Determine the labor and system requirements to perform the analysis of effectiveness of load reduction goal
- Understand if rule-of-thumb metrics can be developed to simplify future analyses

Program Design

The SRP DG pilot began with many of the same stakeholders who worked on the SRP DemandLink initiative, which is overseen by the Energy Efficiency and Resource Management Council (EERMC). Prior to the kickoff of the pilot, OER received support from the EERMC and National Grid to scope the project.

National Grid provided direct guidance and oversight of the Peregrine study that preceded the SRP DG pilot.⁴ Specifically, staff provided feedback on the design of the pilot and guidance to OER on the use of a commercial-scale facility integrated with the Renewable Energy Growth Program⁵. The SRP DG pilot team from National Grid included Ian Springsteel, director of regulatory strategy; Ryan Constable, manager of asset management; and Lindsay Foley, SRP pilot coordinator.

Implementation

The OER representative reported that the right stakeholders were involved—from state personnel to National Grid staff—and that the experience with the involved parties was a positive one. The relationship between OER and National Grid was effective, and OER staff said it was thankful for National Grid's resources and broad, deep knowledge base. OER's internal management staff was also supportive. The SRP DG pilot covered a lot of professional ground, and people on the SRP team had to work with multiple staff across the state level and throughout National Grid.

⁴ Peregrine Energy Group, Inc. *Solar PV for Distribution Grid Support: The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project*. 2014. Available online: http://www.energy.ri.gov/documents/SRP/RI-SRP-PV_Report_Peregrine-team_07-16-2014.pdf

⁵ More information on the Renewable Energy Growth Program may be found here: <http://www.energy.ri.gov/policies-programs/programs-incentives/reg-program.php>

The Solarize program in Tiverton and Little Compton surpassed enrollment expectations. The towns exceeded the Solarize installation targets (400 kW installed versus a 240 kW goal). Combined with the 250 kW Grid Support Solar Field installation, the program resulted in 649 kW of installed solar capacity, exceeding the original goal of 520 kW. Stakeholders attributed multiple factors to the pilot's success in surpassing installation targets. The Solarize portions of this Process Evaluation section below discuss these factors in more detail.

National Grid reported that the pre-study and deployment phases of the SRP DG pilot also went well and were strengths of the program. National Grid and OER agreed that the Grid Support Solar Field solicitation process would have been enhanced with more bidders.

National Grid found that measuring the reliability of the solar installations' impact on peak load over time was a challenge, as the recently installed systems had only a short window of observation.

Solarize Tiverton and Little Compton Kickoff and Marketing Campaign

Cadmus interviewed Danny Musher and Shauna Beland (OER), Matt Ray (formerly of SmartPower), Eric Beecher (Sol Power), and Robert Mushen (town of Little Compton) about their experiences with the kickoff and marketing components of the SRP DG pilot Solarize program.

Objectives

The 2014 Peregrine study, which originally proposed the design for the SRP DG pilot, recommended using a Solarize campaign rather than relying on general residential installations due to the large target volume of the SRP DG pilot. Highly visible Solarize campaigns leverage participation-based tiers of declining costs to encourage high participation. The Peregrine study estimated that approximately 50 residential PV systems were required to achieve load relief targets for the pilot.

OER and REF partnered with SmartPower to implement Solarize programs throughout Rhode Island. They helped coordinate the marketing and outreach efforts of the Solarize campaigns in Tiverton and Little Compton. The program administrators successfully piloted the program in North Smithfield before deploying it in Tiverton and Little Compton. Since then, SmartPower has helped OER and REF launch Solarize campaigns in 16 other Rhode Island towns.

Sol Power (the selected installer for both Tiverton and Little Compton) first learned about the Solarize Tiverton request for proposals (RFP) at a solar stakeholder meeting run by OER and REF. Sol Power was already interested in participating in a Solarize program and was not particularly motivated by the SRP aspect of the Solarize Tiverton RFP. The Solarize Tiverton RFP stipulated SRP DG pilot participation, and Sol Power accepted that. At the time of bidding, some of the pilot project details were not known, at least to Sol Power. Sol Power's primary goal in responding to the RFP was to win the Solarize work to further build its business.

Program Design

According to OER reports and SmartPower, the program administrators executed the Solarize program design well, especially with respect to the marketing and sales approaches taken in Tiverton and Little Compton. The two towns did not apply to become Solarize communities; they were selected to coincide

with National Grid’s overall SRP efforts. Not actively applying to participate in the program meant that they were initially less aware of the program, which required more introductory work for OER at the outset. Once up to speed, Sol Power and SmartPower agreed that the campaigns progressed with minimal incident, which they attributed to the high degree of collaboration between the stakeholders.

SmartPower’s role was to lead the effort of communicating the goals of the program to residents, but found that most were just happy to be adopting solar. Residents did understand that they would receive an additional incentive for their system, but they were less interested in—or less aware of—the benefit to the electrical grid or overall goal of the SRP initiative.

Sol Power had a similar experience and discovered early on not to discuss the details of the incentive until point of sale, typically using it as a passive bonus to close a deal. They found that discussing the details of the incentive created confusion with a potential customer. Even without discussing it however, the incentive allowed Sol Power to reach a far wider group of customers. Under the SRP DG pilot, west-facing systems became financially feasible with the additional SRP funds, especially for those who did not meet REF’s 80% total solar resource fraction (TSRF) threshold.⁶ Those customers below the threshold received a waiver when participating in the SRP pilot, which allowed them to utilize both incentives (SRP and REF funds). South-facing systems continued to benefit from pre-existing REF grant funding, while also benefitting from the tiered pricing of the Solarize campaign, and throughout the marketing campaign, Sol Power saw systems with a wide range of orientations. Figure 1 in the impact analysis section shows a distribution of the system orientations.

This Solarize campaign’s additional incentive was based on Peregrine’s study of residential load reduction and featured tiered incentives. Peregrine initially developed data on the proposed values for incremental incentives based on orientation. OER later realized that shading had a significant impact, especially for peak need, and worked with Peregrine to develop a spreadsheet-based contingency calculation that included shading value, tilt, azimuth, and orientation. Table 3 and Table 4 show the matrices created to determine the capacity based SRP incentive.

Table 3. SRP Locational Rebate (\$/kW-DC) Before Shading Adjustment

Tilt	Azimuth								
	190-200	200-210	210-220	220-230	230-240	240-250	250-260	260-270	270-280
0-10	\$169.03	\$187.13	\$203.86	\$218.72	\$229.11	\$237.31	\$243.08	\$246.26	\$246.72
10-20	\$187.89	\$243.56	\$294.57	\$339.54	\$373.74	\$400.57	\$419.39	\$429.74	\$431.24
20-30	\$88.66	\$129.27	\$188.50	\$262.96	\$350.54	\$449.71	\$557.30	\$576.10	\$578.55
30-40	\$26.62	\$77.13	\$146.82	\$237.91	\$343.75	\$459.75	\$585.67	\$662.31	\$665.48
40-50	\$55.06	\$105.91	\$187.00	\$279.86	\$388.28	\$509.05	\$639.61	\$703.85	\$707.55
50-60	\$0.00	\$177.00	\$294.39	\$384.61	\$488.68	\$591.10	\$697.84	\$723.36	\$727.48

⁶ Commerce Rhode Island. *Minimum Technical Requirements for the Renewable Energy Fund. 2017.* Available Online: <http://commerceri.com/wp-content/uploads/2017/12/RI-REF-Minimum-Tech-Reqs-12.13.17.pdf>

Table 4. 90% of Incremental Distribution Value (\$/kW-DC) Shading Adjustment

Tilt	Azimuth								
	190-200	200-210	210-220	220-230	230-240	240-250	250-260	260-270	270-280
0-10	\$169.03	\$187.13	\$203.86	\$218.72	\$229.11	\$237.31	\$243.08	\$246.26	\$246.72
10-20	\$187.89	\$243.56	\$294.57	\$339.54	\$373.74	\$400.57	\$419.39	\$429.74	\$431.24
20-30	\$171.77	\$267.34	\$354.20	\$430.20	\$485.74	\$529.12	\$559.44	\$576.10	\$578.55
30-40	\$136.84	\$264.65	\$379.92	\$480.13	\$549.70	\$603.83	\$641.58	\$662.31	\$665.48
40-50	\$77.34	\$235.34	\$376.94	\$499.32	\$577.63	\$638.37	\$680.66	\$703.85	\$707.55
50-60	\$0.00	\$177.00	\$349.39	\$497.62	\$584.26	\$651.27	\$697.84	\$723.36	\$727.48

Table 3 represents the base SRP incentive, and is determined by the system’s tilt and azimuth. The variation in incentive value is designed to offset the lower annual generation as orientation shifts westward. However, this does not necessarily reflect the final incentive value. Table 4 is the shading adjustment table. To calculate the incentive for each system, the installer would conduct a solar access analysis over the three summer peak hours, from 4 p.m. to 7 p.m. This solar access percentage is multiplied by the corresponding value in Table 4. The SRP incentive value is the lower of the two numbers from Table 3 and Table 4. See in Appendix B for additional detail on the calculation and methodology of the SRP incentive.

In practice, Sol Power found this spreadsheet difficult to use, and it resulted in some miscalculations of incentive values. Sol Power said that the original incentive table created unintentional ambiguity and recommended developing a user-friendly calculator, where they would simply input system variables such as tilt, azimuth, and system size to determine the incentive. The table included an overlapping range of azimuth ranges (e.g., 180-190, 190-200), rather than separate bins (e.g., 180-189, 190-199). This overlap caused some confusion in determining incentive value. Sol Power suggested that before finalizing the incentive value for each customer, the values should be sent to OER for final approval. Sol Power was also initially unsure about how shading factored into the incentive value using Table 4.

OER agreed that a better explanation of the incentive calculations would have helped Sol Power and, in hindsight, that it should have given Sol Power more information about which values to choose for overlapping tilt and azimuth.

When the solicitation for the Solarize campaign was released, OER received only one bid for Little Compton and two for Tiverton. This was likely due to the relatively remote locations, fewer available installers at the time of solicitation, and insufficient advertising. Another unintended consequence of running the Solarize initiative in these particular communities was that there were many seasonal residents who were not in the area for most of the campaign. The campaign ran from January 2015 through June 2015, and Sol Power noted that it continued to receive leads via referral throughout the summer. The Little Compton municipal officials suggested shifting or increasing the time frame of the campaign to incorporate Memorial Day through Labor Day to engage more summer residents.

Sol Power decided to bid for the Solarize program because of the potential high volume of leads and installations, and said that the publicity and name recognition that resulted from being the installer for

the SRP DG pilot was also appealing. From Sol Power's perspective, the SRP DG pilot portion of the solicitation was ambiguous and would have benefitted from specificity. Sol Power assumed that it would be selecting the data acquisition systems for the installations, but, in fact, OER chose the meters. Sol Power also understood that there would be an additional incentive, but it was uncertain of the value of that incentive. Sol Power acknowledged that it was very interested in pursuing the Solarize business, even with the uncertainty surrounding some of the RFP requirements.

Outside of the challenges implementing the SRP incentive, Sol Power found the inclusion of the 2014 Peregrine study to be helpful context. Even with the study, Sol Power did not have a clear understanding of what participation in the SRP DG pilot project would entail. It also was unsure of participation-rate goals or target participation rate. Sol Power knew that the Solarize North Smithfield program resulted in 84 signed contracts, but it was unaware of any goals for Tiverton or Little Compton.⁷ Overall, the project would have gone more smoothly for Sol Power if the solicitation had more explicitly addressed the incentive, required hardware, and role of the installer.

Additionally, the feeders that are the focus of the SRP DG pilot included all of Little Compton and only part of Tiverton. OER originally intended to offer the SRP incentive to all residents in both towns in order to simplify program execution and messaging. Sol Power, however, thought the incentive was unavailable to customers not connected to the target feeders. They limited their messaging about the program in those areas, as verifying a potential customer's feeder complicated their marketing and customer acquisition process.

Implementation

The high level of collaboration was a strong asset of the campaign, with SmartPower stating it was "absolutely beneficial" to the success of the campaign. SmartPower stated that, apart from the incentive calculation, the campaign was well executed. OER explained that National Grid's involvement with the Solarize campaigns was limited to promoting the DemandLink program. However, representatives from National Grid did attend Solarize events as well. Little Compton municipal officials said the campaign also succeeded because residents viewed it as a good, local effort rather than something run by a collection of out-of-town firms.

The inclusion of the SRP incentive in the Solarize campaign required SmartPower to add an extra level of detail for the Little Compton and Tiverton campaigns compared to previous campaigns. SmartPower had to address both the new incentive and reach out to a community that had not actively requested Solarize status and was, therefore, generally less aware of solar. They increased their focus on community education during the early marketing and engagement portion of the campaign, which SmartPower accomplished through community workshops and distribution of educational materials. The increased outreach came with the added benefit of increasing the campaign's general exposure to the community as well.

⁷ Solarize contracts are available online: <http://www.energy.ri.gov/policies-programs/programs-incentives/solarize-ri.php>

Sol Power reported that there were three community workshops per town, and the company estimated that it and SmartPower spent 10 to 15 hours per community at the workshops, or two to three hours per workshop. The Little Compton municipal officials said that SmartPower and Sol Power did a good job explaining the costs involved, state and federal incentives, the net energy savings that customers would receive, and payback time. Sol Power demonstrated the differences in the panel configuration and discussed how orientation would impact project financials.

SmartPower said that developing community interest, understanding, and excitement was a key part of the success of the campaign. Little Compton had strong town hall turnout of 20 to 30 people, while Tiverton drew fewer people. SmartPower noted that Solarize campaigns are a valuable tool that will be different for every community and suggested using Little Compton campaign as an example of success.

Unlike SmartPower, Sol Power’s approach to marketing its Solarize campaign did not vary much from its typical sales approach. The main difference was that Sol Power could now target more potential customers because the SRP DG pilot incentive enabled sites with a wider range of roof azimuths to be considered for development. Prior to the sales discussion, Sol Power spent time on web development and social media outreach, as well as sending out flyers and mailers, advertising in local newspapers, and conducting door-to-door outreach. Sol Power also found collaborating with the towns beneficial to the marketing outreach, as being preselected and endorsed by the towns improved customers’ first impressions of the company. Town staff also sent marketing materials to residents informing them of the Solarize campaign.

Table 5 shows the results of the Solarize outreach campaign. The general sales category refers to leads generated through general sales staff, whose sales approaches still benefitted from the publicity and financial incentives of the SRP DG pilot.

Table 5. Lead Sources and Conversion Rates for Solarize Tiverton and Little Compton

Lead Source	Leads Generated	Conversion Rate	Leads Converted	% Total Leads
Workshops	53	25%	13	20%
Mailers	70	23%	16	26%
Solarize RI Website	32	9%	3	12%
Newspaper	18	39%	7	7%
Word of Mouth	11	27%	3	4%
Social Media	6	17%	1	2%
Town Outreach	7	14%	1	3%
General Sales	71	18%	13	27%
Total	268	-	57	100%

Approximately 26% of the leads came from various mailers (with 23% conversion rate), and about 20% of leads were generated from the workshops (with a 25% conversion rate). The campaign generated 147 leads in Tiverton and 121 in Little Compton.

OER credited the favorable conversion rates to Sol Power’s approach of providing the customer with a quote early in the process and then executing a contract, thereby avoiding the “sticker shock” that can

sometimes be associated with solar development. Sol Power also quickly updated its SRP Solarize sales pitch. After a few unsuccessful attempts to succinctly convey the detailed reasoning behind the SRP DG pilot, it dropped some of the information about the additional incentive for west-facing systems because residents already received information on this topic throughout the Solarize outreach process. Even when provided with less-detailed information, customers did not provide much feedback or ask many questions. Both SmartPower and Sol Power reported that most customers were just excited to be “going solar” and were not very interested in the details of the SRP incentive.

OER, Sol Power, and SmartPower all noted that the program had a better experience in Little Compton than in Tiverton. Those interviewed offered a few reasons to explain their reasoning. SmartPower suggested it was because of the close-knit nature of the Little Compton community and said the outreach may not have been as successful in a larger community like Tiverton. For reference, Little Compton has a population of about 3,500 according to the 2010 census, while Tiverton has a population of more than 15,000. Sol Power said there were about 20 coordination calls between SmartPower, OER, Sol Power, and Little Compton municipal officials throughout the marketing campaign, and Tiverton officials were not always able to participate in the calls. Additionally, Sol Power said that the town manager of Little Compton was a Solarize participant, leading him to naturally be more engaged.

Overall, OER reported that engaging town residents was easier than it had anticipated. The Little Compton municipal officials agreed, stating that they could easily collaborate whenever they presented in public with Sol Power and SmartPower. Support from the Black Goose Café also bolstered early campaign efforts, which served as an informal solar ambassador and hosted an open house for anyone interested in the Solarize campaign. The café owners were early Solarize customers and were happy to serve as an example for the community.

Solarize Tiverton and Little Compton Installation

Cadmus interviewed Danny Musher and Shauna Beland (OER), Matt Ray (formerly of SmartPower), Eric Beecher (Sol Power), and Robert Mushen (town of Little Compton) about their experiences with the installation component of the SRP DG pilot Solarize programs.

Implementation

When presenting the details of the SRP DG pilot incentive as part of the Solarize program, Sol Power found it difficult to convey the full details and reasoning behind the incentive. The company included a slide discussing the feeder load-reduction strategy, but said it was not the main goal of the presentation. After a few unsuccessful pitches, Sol Power simplified its presentation and told potential customers that they would be participating in a regional study, that the utility infrastructure was at capacity, and that installing solar would help the town save money. Sol Power did not provide detail on peak usage or load reduction, and it said that most potential customers did not have any knowledge about feeders.

Most potential customers did not have a choice in their system’s orientation due to the fixed pitch and azimuth of their roof. However, for those who had a choice, Sol Power presented two quotes: one for a typical south-facing system and one optimized to take advantage of the SRP incentive. Sol Power found that customers would choose the SRP-incentivized system designs due to lower upfront costs.

REF grants funded all Solarize systems because third-party ownership of solar systems in Rhode Island was still prohibited at the time. All SRP-funded sites were exempt from REF’s 80% TSRF threshold. This meant customers with sites below REF’s threshold could only take advantage of the incentives if they participated in the pilot.⁸

Sol Power found that the incentives were generous enough to make SRP DG pilot systems competitive with south-facing systems. The incentives also increased the breadth of customer sites, which led to higher conversion rates: Sol Power converted 121 leads to 27 contracts in Little Compton, and 147 leads to 28 contracts in Tiverton (it should be noted that the signed contracts figures differ slightly than the actual installed systems from Table 1, as a few systems were enrolled in the pilot after the conclusion of Solarize). Table 6 below shows the conversion rates of all Rhode Island Solarize campaigns to date. The average campaign conversion rate was 19.15%. Tiverton experienced an average conversion rate of 19.05%, while Little Compton had an above average rate of 22.3%.

Table 6. Solarize Rhode Island PV Adoption Rates

Municipality:	Start Date	End Date	Total Leads	Total Contracts	Sales Converted %	Contracted Capacity (KW)
N. Smithfield	10/10/2014	12/15/2014	270	84	31.11%	623.7
Tiverton	12/22/2014	5/8/2015	147	28	19.05%	183.66
Little Compton	12/22/2014	5/8/2015	121	27	22.31%	204.34
Foster	10/26/2015	2/15/2016	87	9	10.34%	58.96
Barrington	10/26/2015	2/15/2016	235	30	12.77%	200.82
S. Kingstown	10/26/2015	2/15/2016	336	52	15.48%	354.98
Middletown	10/26/2015	2/15/2016	229	41	17.90%	264.11
Portsmouth	10/26/2015	2/15/2016	201	69	34.33%	528.34
Newport	10/26/2015	2/15/2016	246	49	19.92%	331.52
Aquidneck Island (Combined)	10/26/2015	2/15/2016	676	159	23.52%	1123.97
Providence	3/28/2016	8/19/2016	240	32	13.33%	191.6
Warren	3/28/2016	8/19/2016	127	39	30.71%	287.13
Bristol	3/28/2016	8/16/2016	139	19	13.67%	142.06
Charlestown		10/6/2017	321	54	16.82%	309.44
Cranston		10/6/2017	248	67	27.02%	449.58
Warwick	7/25/2016	11/30/2016	125	5	4.00%	32.36
Bristol	10/26/2017	4/27/2018	117	31	26.50%	261.23
Barrington	10/26/2017	4/27/2018	205	41	20.00%	251.22
S. Kingstown	10/26/2017	4/27/2018	321	16	4.98%	78.9

⁸ Although incentive structures were not explicitly discussed with stakeholders, it is important to note that future systems incorporating third-party power purchase agreements may not offer effective incentives to motivate participants to design arrays in any other orientation than that which maximizes PV generation.

Other than educating customers about the SRP incentive and installing the program-required Solar Log Data Acquisition System, Sol Power followed its typical installation practices for Solarize systems. At the time, the Solar Log meters were newly launched in Europe and had little testing in the United States. Sol Power was unfamiliar with installation best practices, which led to increased installation times, deployment delays, and numerous meter replacements, sometimes months after completing the installation.

Sol Power cited several reasons for the issues encountered with installed meters. For example, Tiverton and Little Compton have poor cellular reception, which necessitated the use of meters that relied on Ethernet or satellite connections to communicate. For consistency, Sol Power suggested using only Ethernet meters in the future, because the satellite and cellular meters were both less reliable. Sol Power also found that some meters were not functioning properly and needed to be replaced. Some of these meter discrepancies are still issues at sites across Tiverton and Little Compton. Sol Power remains unclear about its responsibility for maintaining and servicing the installed meters, and about its role after the program ends.

When asked about customer comments, Sol Power did not provide many examples. The company received some complaints about the need to reinstall meters. While Little Compton municipal officials also received little customer feedback, it was all positive.

Sol Power experienced an increase in business because of its participation in the Solarize campaign. The company received a lot of local exposure and increased its brand recognition. Sol Power improved its qualifications and won other Rhode Island Solarize programs, and it also received follow-up work in Tiverton and Little Compton. Sol Power estimates that it received six to eight referrals, or 10% to 14% of its original Solarize sales.

Sol Power would participate in a similar Solarize program if it were offered again. The extra incentive to homeowners improved business development outreach efforts and effectiveness, and Sol Power said it helped the industry overall. Sol Power said that the program will help demonstrate that installing solar is a viable option when considering adding new electrical infrastructure to the utility grid.

Grid Support Solar Field

The 250 kW single-axis tracking array went online in July 2017, and Cadmus spoke with system developer Scott Milnes of Econox Renewables to discuss his experience. Cadmus also spoke to Julian Dash of Clean Economy Development (CED) and Palmer Moore of Nexamp about the Grid Support Solar Field RFP, and about why those firms decided not to bid on the project.⁹

Objectives

CED, Econox, and Nexamp were initially drawn to the RFP because of their continued interest in the Rhode Island renewable energy market. CED attended the Rhode Island Distributed Generation Board's

⁹ The Grid Support Solar Field RFP is available online: <http://www.purchasing.ri.gov/bidding/ContinuousRecruitment.aspx> - see CR-38.

meeting and the bid meeting where the RFP was discussed. Nexamp received the RFP via an OER distribution list. Both firms were initially interested in the project.

Program Design (Non-Bidders)

CED quickly decided not to bid on the solicitation due to uncertainty associated with the total amount of available funding. CED was under the impression that OER was interested in selecting more than one project with the available funds. CED determined that the total RFP budget (no more than \$200,000) would not be enough for more than one project.

For Nexamp, the proposed system size and corresponding incentives were smaller than what it usually works with, and project was not deemed a cost-effective one for the firm to undertake. The risk of underfunding was a significant concern and both firms would have appreciated greater clarity about the funding on a per-project basis.

Program Design (Bidder)

At the time the RFP was released, Econox was already pursuing development of multiple medium- and large-scale commercial PV systems in the area for the Renewable Energy Growth program. The company presented the RFP to its customers as an opportunity, and tailored project development to match the bid requirements. Like the non-bidding installers, Econox said that developing a project in the area without a prospective site would have been difficult. Responding to the RFP without already having a site in mind would have introduced additional uncertainty and upfront customer acquisition investments for the developers. It required all potential bidders to have a potential project for the RFP, then sell that project to a client. Not all sales are successful, which may have contributed to the lack of responses. Econox attributed its decision to respond to the bid as largely being at the “right place at the right time.”

Econox and its client moved forward with project development and used the incentives in the RFP to influence the design of the system. For example, Econox does not usually develop tracking PV arrays in the Rhode Island area. The more complex arrays tend to have additional installation and maintenance costs, and are more prone to mechanical issues. After reading the RFP and supporting incentives, the company decided that the single-axis array would be worth pursuing in this case. Econox did note that site-specific RFP requirements can increase development complexity, but Econox credits OER for making bidding on the project a smooth process.

Implementation (Non-Bidder)

Overall, CED was excited by the goals of the project, but was put off by geographic limitations and uncertainty around funding. CED did not have any small projects in the Tiverton or Little Compton areas, and would have had to spend time and effort to identify and sell a project. Trying to develop a new project in a new area (for a smaller project) would be a significant investment. If the RFP requested project development in a region where CED already had a presence, and if the firm had a potential project lined up, CED would have bid.

Nexamp was initially interested by the solicitation's release and did not want to walk away prematurely. In identifying a potential system, it deemed a ground-mounted system of the capacity requested in the RFP would be too small to be cost-effective. Instead, it attempted to identify potential rooftops that could host the entire capacity. After performing initial due diligence, Nexamp could not identify a potential rooftop site for development, especially one with an azimuth within the range detailed in the RFP. The lack of a potential rooftop option stopped Nexamp from moving forward.

Nexamp found the RFP to be well designed, well written, and easy to understand. The goals were clear, and the incentives and costs were clearly defined enough to run a financial analysis. If the RFP had been for a system closer to 1 MW in size, it would have been much more likely to respond.

Implementation (Bidder)

The project came online in July 2017, later than initially planned. Although responding to the RFP went smoothly, the developer ran into unforeseen complications prior to construction. The tracking array is customer-owned, and Econox and their customer encountered stumbling blocks securing financing for the project. There were a few factors that contributed to the financing issues. The project required a large amount of capital upfront, and incentives such as OER's "Solar PV for Distribution Grid Support" grant and U.S. Department of Agriculture grants are not awarded until project completion. For a single entity such as Econox's customer, rather than a large solar developer, that represented a significant amount of capital. Additionally, the single-axis tracking array proved difficult to explain or justify to various financiers. Econox and their customer initially went to local banks, but many were uncomfortable or unfamiliar with the type of project and did not want to take the risk. Project financing was held up twice before construction began, and eventually went forward with financing from Avadia Bank. Once financing was secured, however, system construction progressed quickly. Both OER and National Grid were helpful throughout the process and expedited the system's interconnection after construction was complete.

Once operational, the owner maintains the system, with Econox addressing warranty issues and post-construction glitches that may occur, as well as providing spare equipment in the event of failure later in the system life span. Econox has already reported some initial issues with the array tracking and a mechanical issue associated with tracking motors that needed to be replaced. The developer stated that most of the issues associated with a new system have been identified and resolved, and it expects the system to continue running smoothly.

Impact Evaluation

Cadmus analyzed National Grid feeder data and production data from residential PV systems with functioning Solar Log data acquisition systems and other suitable monitors in Tiverton and Little Compton from June 1, 2016, through September 30, 2017. The priority of this analysis was to quantify the impact that the SRP DG pilot systems had on reducing peak demand for the local distribution system during the summer. Of particular interest was whether the systems achieved the pilot's 250 kW peak load reduction target. Only 39 sites out of the 57 had any hourly generation data during either the summer of 2016 or of 2017. Of the 39 residential sites that had hourly generation data available, only 19

sites in 2016 and 27 sites in 2017 met the criteria of having usable data for 80% of summer (June, July, and August) hours. This report refers to the systems at these residential sites as the *fleet*. The Grid Support Solar Field project (249.9 kW-DC single-axis ground-mounted system referred to as the *field*) came online in July 2017 and had near-complete hourly data throughout July and August. Table 7 shows the capacities and counts for these system types and the extent to which measurements from the incentivized systems were used in the analysis.

Table 7. Installed Capacity and Number of Systems for Deployed Solar PV*

Value	Monitored Summer 2016*		Monitored Summer 2017		All Incentivized**	
	Rooftop-Mounted (Fleet)	Ground-Mounted (Field)	Rooftop-Mounted (Fleet)	Ground-Mounted (Field)	Rooftop-Mounted (Fleet)	Ground-Mounted (Field)
Installed Capacity, kW-DC	129.7	0	177.7	249.9	395.2	249.9
Number of Systems	19	0	27	1	57	1

* Systems that had sufficient data available (80% of summer hours) are included in the analyses.

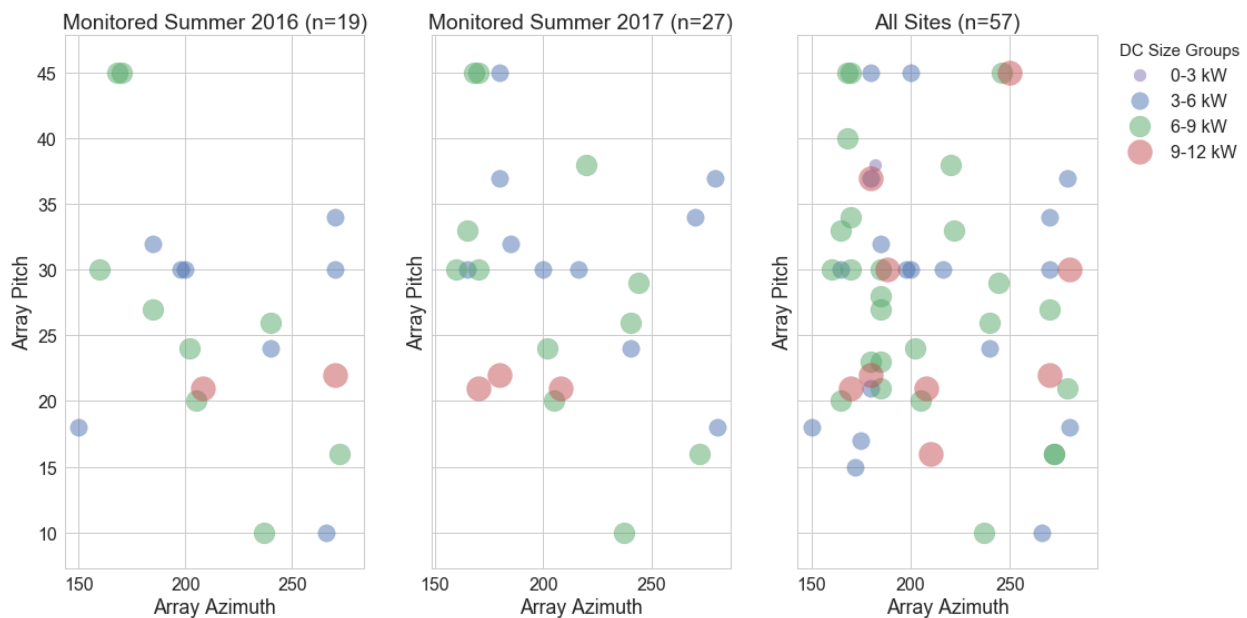
**All systems that received funding from the SRP program.

The main issue identified with data collection for the roof-mounted systems was that most systems were not reporting any generation information to the online data acquisition service. Although the number of reporting systems increased from 2016 to 2017, the lack of complete data was an issue that persisted throughout the evaluation. Given that measurements were only available for a subset of all SRP DG Pilot participants, it is important to view the results within this context. Where appropriate, Cadmus extrapolated values to all incentivized systems.

Beyond presenting realized impact metrics, Cadmus made estimates based on the measured generation rates to determine the power capacity of various system types needed to make sizable load reductions (5%, 10%, 15%) during the top 10% of loading hours, called the coincident hours. We also used rebate payments for residential systems to estimate total costs for installing these system capacities at various orientations (south, south-west, and west). Finally, we briefly considered how various sizes of energy storage systems could reduce max loading.

Figure 1 shows scatter plots depicting the sizes and orientation of the roof-mounted systems that participated in the pilot’s Solarize campaigns. The graphics clearly illustrate that the monitored systems that have usable generation data cover a more limited distribution of orientations compared to all 57 installed Solarize sites. The x-axes correspond to the azimuth orientation, with 180 being directly south-facing and 270 being directly west-facing. The y-axes correspond to the pitch of the arrays. The plots on the left and center show systems that met the data quality criteria to be included in the summer 2016 and summer 2017 impact metrics, respectively. The plot on the right shows all 57 installed Solarize sites.

Figure 2. Pitch and Azimuth of Solarize Roof-Mounted Arrays Participating in the Pilot



PV Capacity for Demand Management

The first issue to consider is the amount of solar PV-produced power that was generated in tandem with the consumption of power, particularly during the periods of high consumption. Given that the SRP pilot tracked and incentivized system sizes as the sum of the solar module DC power capacities, capacity factors (reported as percentages) were determined as AC power generation normalized by DC nameplate capacity. Therefore, reported capacity factors do not introduce any assumptions on the inverter efficiencies or other losses but, rather, include them directly. Cadmus split rooftop-mounted systems into groups based on their orientation: we considered azimuths less than 202.5 degrees south, greater than 247.5 degrees west, and values between southwest. However, we found the average capacity factors for each orientation group to be relatively similar. Based on data available from 2017, the annual capacity factors for south, south-west, and west-facing systems were 14.8%, 15.8% and 13.2%, respectively.

Table 8 lists the capacity factors for the two summer periods, including the specific peak and off-peak periods as defined by the 2016 Rhode Island Technical Reference Manual (TRM).¹⁰ Using these definitions, the capacity factors do not vary significantly with the orientation of the rooftop systems. This would suggest that western systems are not offering more demand relief than southern-facing systems; however, because the peak and off-peak definitions from the TRM are generalized for the whole state and do not reflect the specific conditions of the substation's feeders, these metrics are not a true representation of the realized peak reduction at this location. In addition to average capacity factors for each system group, we also determined the average standard deviations for each hour in the day for each TRM defined period. The standard deviation reflects the hourly variability of the resource,

¹⁰ Rhode Island Technical Reference Manual is available online: <https://www.nationalgridus.com/media/pdfs/our-company/eereports/py2016-ri-trm.pdf>

with higher values signifying a greater tendency to deviate from the average value for the given hour in the day. For 2017, the field system had a slightly higher standard deviation than any of the rooftop-mounted group orientations. This difference in variance could indicate that the fleet systems are inherently less prone to be uniformly affected by variations in cloud cover due to their distributed nature.

Table 8. Average and Standard Deviation of Capacity Factors for Each System Group (2016 and 2017)

System Type	Orientation	Summer 2016*			Summer 2017		
		All Hours	TRM Peak Hours*	TRM Off-Peak Hours**	All Hours	TRM Peak Hours*	TRM Off-Peak Hours**
Average Capacity Factor for each System Group (left) during the Specified Period (above)							
Roof-Mounted	South	20%	30%	7.9%	18%	26%	7.8%
	Southwest	20%	31%	7.9%	20%	29%	8.6%
	West	20%	30%	7.9%	19%	27%	8.1%
Ground-Mounted	Single Axis	n/a	n/a	n/a	20%	29%	9.0%
Average Standard Deviation across each Hour in Day for each System Group during the Specified Period							
Roof-Mounted	South	7.5%	11.2%	7.3%	8.1%	12%	6.7%
	Southwest	7.7%	11.5%	7.8%	9.2%	14%	8.1%
	West	7.6%	11.3%	7.5%	8.5%	13%	7.5%
Ground-Mounted	Single Axis	n/a	n/a	n/a	10%	16%	8.7%

* Summers during peak and off-peak periods as defined by the 2016 Rhode Island TRM.

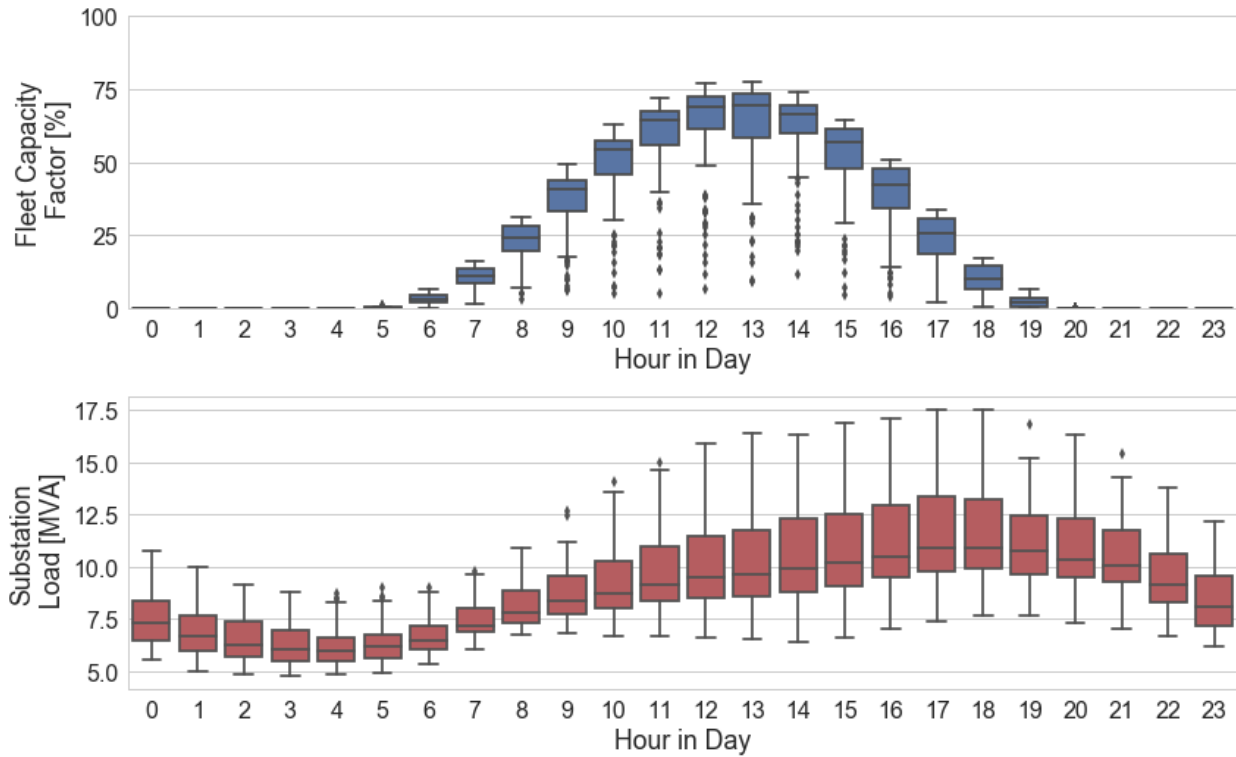
* TRM peak hours: 8:00 a.m. to 9:00 p.m. daily on Monday through Friday, excluding holidays.

** TRM off-peak hours: Weekdays 9:00 p.m. to 8:00 a.m., and all day on Saturdays, Sundays and holidays.

The time periods specified in the TRM cover a rather long period during the day and do not directly correspond to peak loading hours observed at the Tiverton substation. To properly quantify the load reduction benefit realized, it is critical to evaluate the specific hours during which PV systems generated power in relation to the actual loading occurring on the distribution system.

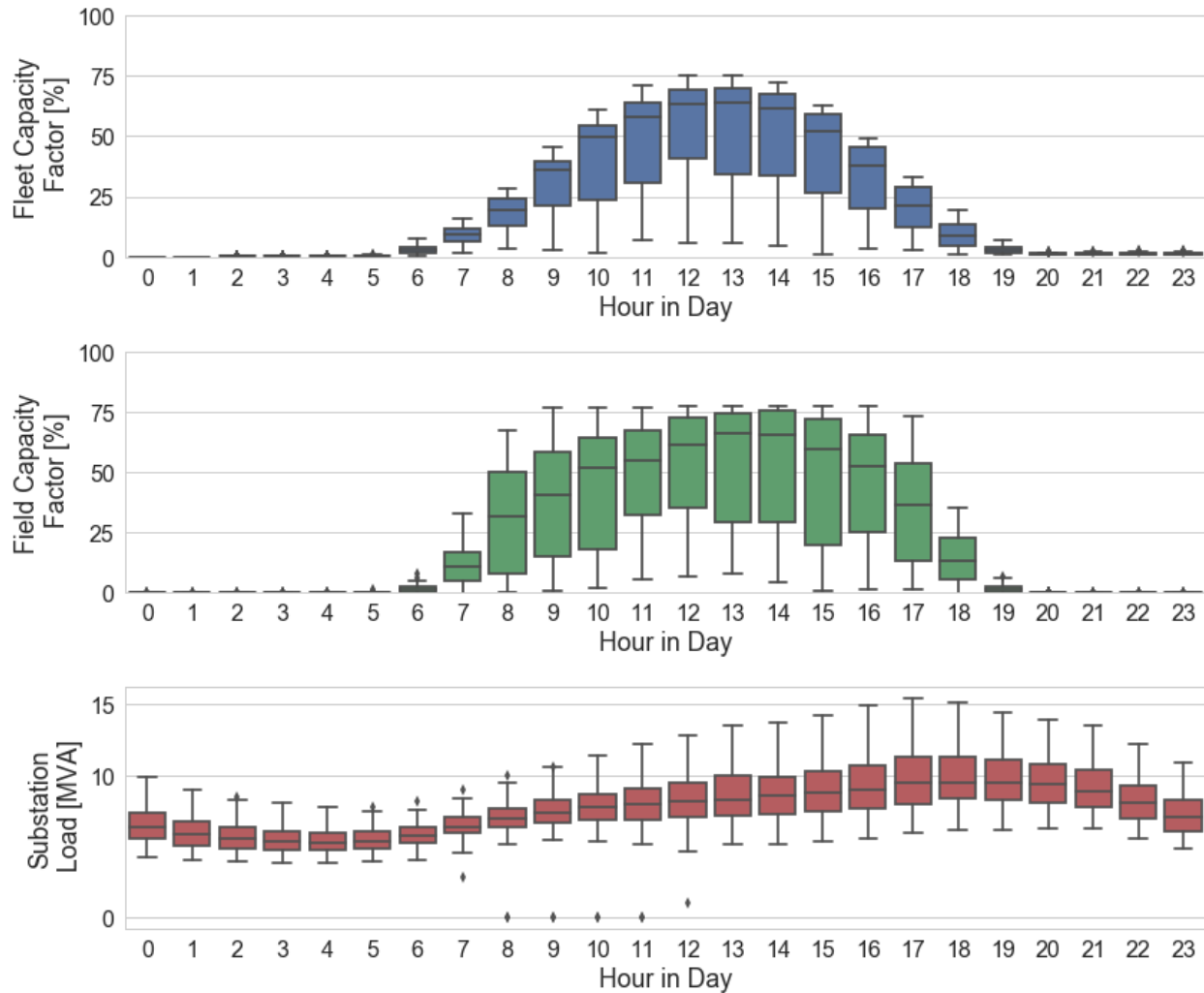
Figure 2 and Figure 3 show the capacity factors of the PV systems along with total loading data measured at the substation. We grouped these values to every hour of the day and the figures present them as box plots. Figure 2 shows data from 2016, before the 250 kW field system was installed, so the only PV systems available were rooftop-mounted systems. We averaged the capacity factor for the fleet for each hour before grouping it by the hour of the day. Cadmus produced Figure 3 in the same manner with data from 2017, but also included the hourly capacity factors for the field system. These figures illustrate the variance of periods of loading throughout the day; they also show that the peak generation from solar PV does not align with the peak loading on the feeder.

Figure 3. Capacity Factor and Substation Load Grouped by Hour for Summer 2016 (92 days)*



* The average capacity factor for the whole fleet is determined for each hour and then grouped to hour in the day. Similarly, the total load at the substation has been grouped to the hour in the day. Boxplots presented in this figure and the figures below are produced such that the top, middle, and bottom of the boxes correspond to the third (Q3), second (median), and first (Q1) quartiles, respectively. The whiskers extend to the most extreme data point contained within 150% of the interquartile range (Q3-Q1) from the median. Any data falling outside the range defined by the whiskers are plotted as individual points.

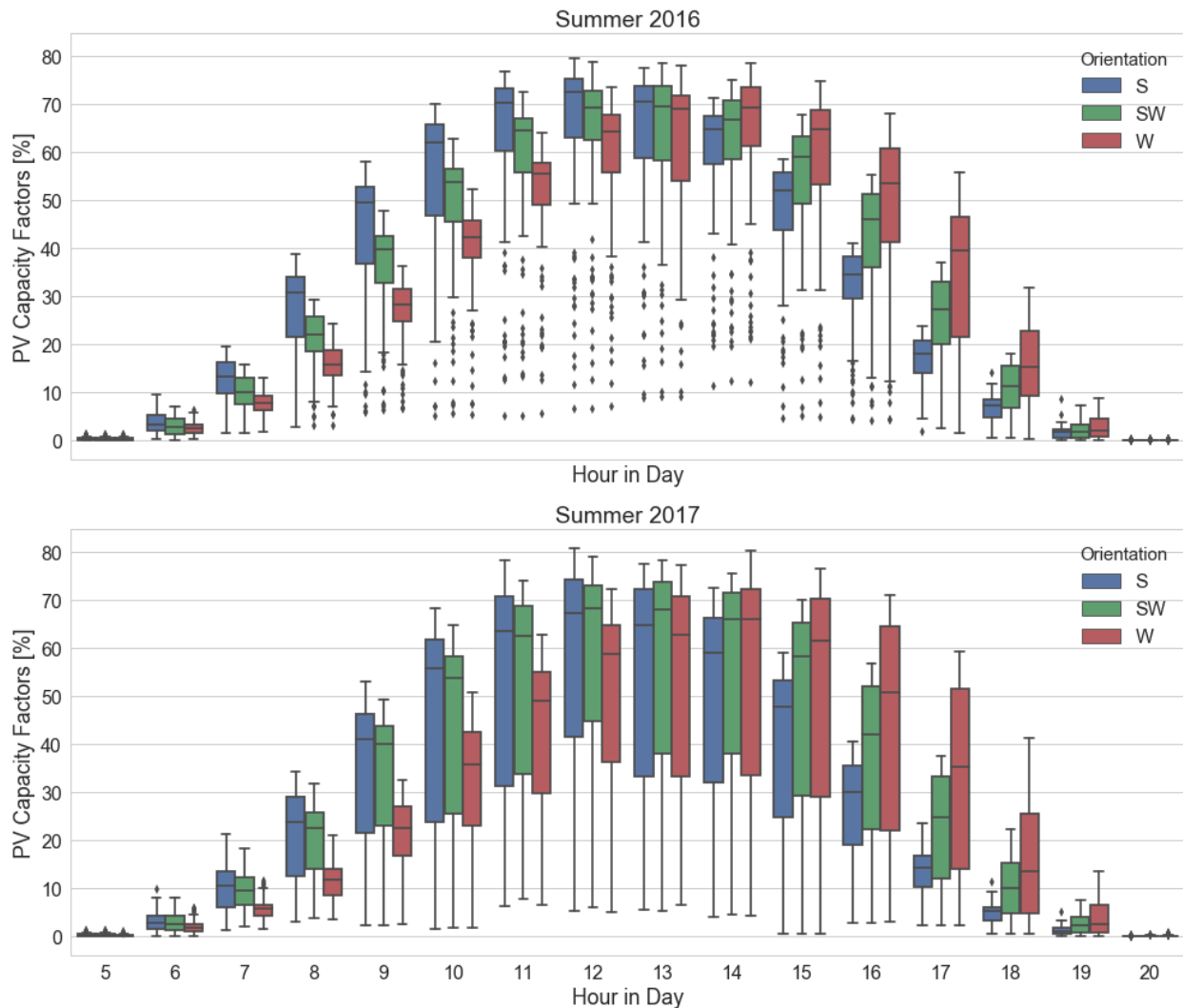
Figure 4. Capacity Factor and Substation Load Grouped by Hour for Summer 2017 (92 days)*



* As in Figure 3, the capacity factor for the whole roof-mounted fleet has been determined for each other and then grouped to hour in the day. The same was done for the capacity factor of the centralized field system. The substation load has also been displayed by hour in the day. The peak in 2017 was noticeably less than the peak in 2016.

When comparing the field system to the fleet systems, the inclination-variation capability of the ground-mounted field system does enable higher capacity factors during early morning and later afternoon hours. This is because the field system can orient the arrays along the single axis to optimize the direction of solar irradiance. The rooftop units, in contrast, are fixed in their orientation. However, by grouping the fleet into south, southwest and west-facing systems, it is possible to observe that fixed orientation leads to distinct capacity factor ranges during the morning and afternoon hours, as shown in Figure 5.

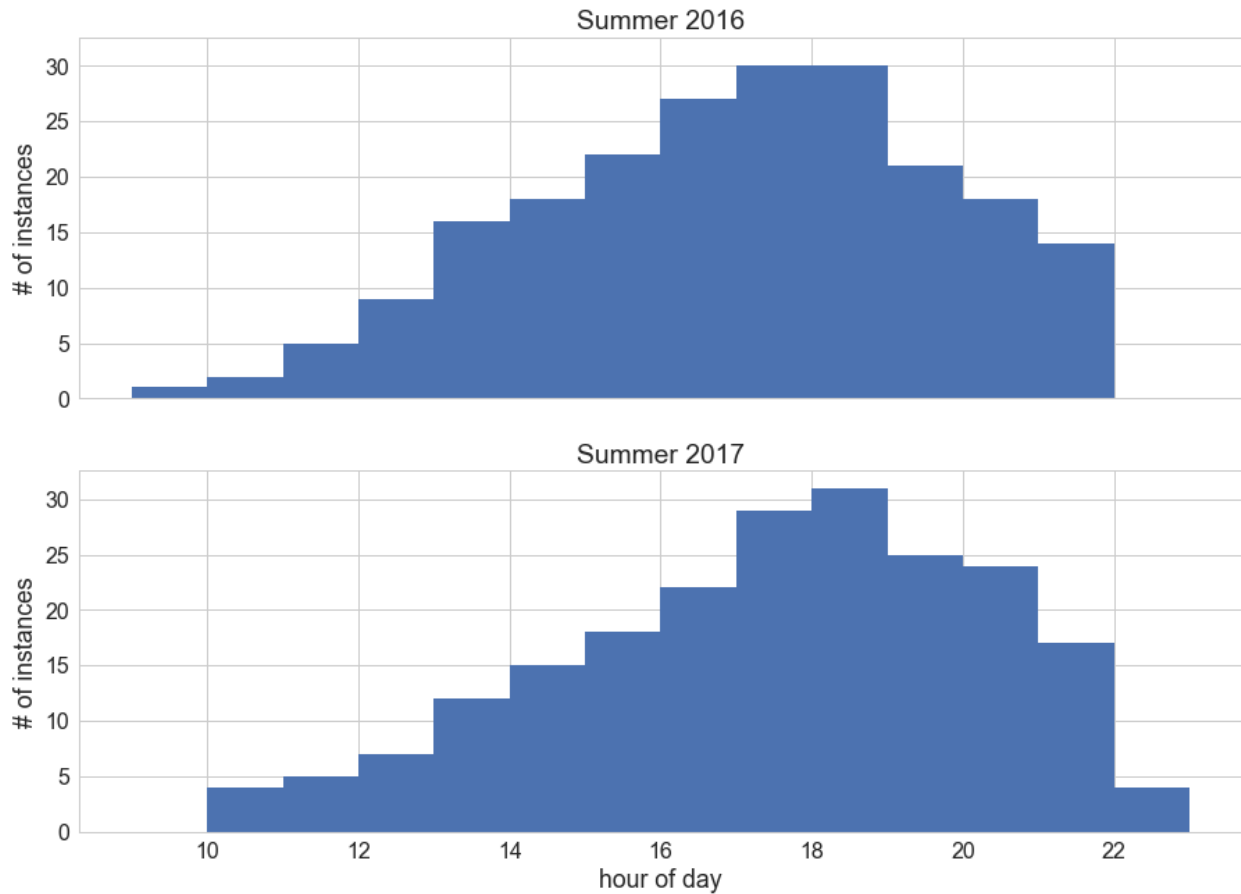
Figure 5. Capacity Factors of Rooftop-Mounted System During Hours of Sunlight by Orientation*



*Of 19 rooftop systems in the fleet that met the data coverage criteria for 2016, nine were oriented south, five were oriented southwest, and the remaining five were oriented west. Of 27 rooftop systems in the fleet that met the data coverage criteria for 2017, 13 were oriented south, eight were oriented southwest, and the remaining six were oriented west.

As depicted in Figure 5, as the orientation of the systems transitions from south-facing to west-facing, the capacity factor during the late day hours increases. As depicted in Figure 2 and Figure 3, the peak loading hours occurs later in the day, so west-facing systems, specifically, are going to offer more load relief compared to south-facing systems. Moving beyond the peak definitions taken from the TRM, it is possible to consider the peak of the substation during hourly intervals when the energy usage was within the top 10% of the summer. These hours, called the *coincident hours*, represent time periods when solar PV generation downstream of the substation is most valuable. In 2016, the coincident hours all occurred between 9 a.m. and 10 p.m., with half the hours occurring between 3 p.m. and 8 p.m. In 2017, the coincident hours all occurred between 10 a.m. and 11 p.m., with half the hours occurring between 3 p.m. and 7 p.m. Figure 6 displays the distribution of coincident hours in 2016 and 2017.

Figure 6. Distribution of Coincident Hours for the Summer of 2016 and 2017*



*For the summer of 2016 and 2017, Cadmus identified the top 10% of hourly energy usage (a total of 213 hours). We identified these hourly intervals by the leading hour and then produced histograms to visualize their distributions. As shown in the figures above, all coincident hours were contained by 9 a.m. and 11 p.m. but were distributed in such a way that afternoon and evening hours were the most common periods.

By first filtering the solar PV generation data to these coincident hours, our team could readily quantify the impact of the power generated to directly offset demand during peak periods. This is more accurate compared to using the TRM’s definition of peak (which does weight specific hours in the day). The Peregrine study also took this approach by defining a “load-weighted distribution contribution percentage,” which considers generation during the top loading hours. This report refers to the power generation normalized by nameplate capacity during these coincident hours as the “coincident capacity factor”, which can be interpreted as the same metric used by Peregrine.

Table 9 lists the coincident capacity factor and mean coincident power generation for both summers (listed by system type and orientation) for each system type, as well as the total installed DC capacity for each system.

Table 9. Installed Capacity of Monitored Systems along with Coincident Capacity Factor, Mean Coincident Power Output, and Coefficient of Variance for the Coincident Power Output

System Type	Orientation	Summer 2016				Summer 2017			
		Monitored Installed Capacity, kW-DC	Coincident Capacity Factor, kW-AC/kW-DC	Mean Coincident Power Output, kW-AC	Coefficient of Variance for Coincident Power Output	Monitored Installed Capacity, kW-DC	Coincident Capacity Factor, kW-AC/kW-DC	Mean Coincident Power Output, kW-AC	Coefficient of Variance for Coincident Power Output
Roof-Mounted	South	58.7	27%	16.1	94%	87.5	21%	18.1	122%
	South-west	39.2	31%	12.1	85%	60.1	26%	15.8	96%
	West	31.8	33%	10.6	80%	30.1	28%	8.6	90%
Ground-Mounted	Single Axis	n/a	n/a	n/a	n/a	249.9	32%	80.1	93%
Total Measured		129.7	30%	38.8	87%	427.6	28%	121.3	95%
Extrapolated to Program*		395.2	30%	117.0	n/a	645.0	27%	174.4	n/a

* To estimate the impact of the whole program, residential roof-mounted systems that were not monitored were included such that their generation rate was the same as their azimuth group (i.e., south, southwest, west). For 2016, the ground-mounted system was not included but all 57 residential systems that received incentives were included. For 2017, the extrapolation also includes the ground-mounted system.

The coincident capacity factor is an average across all 213 hours from each summer, and so there is naturally variation among the set of measured values. To quantify, we calculated the coefficient of variance (i.e., the mean value divided by the standard deviation) for each capacity factor. The smaller the coefficient of variance, the less the power output varied from the average during the 213 hours. For both years, west-facing systems had the lowest coefficient of variance than any other system type. South-facing systems had the highest coefficient of variance, which reflects their high variability in generation during coincident hours. Cadmus determined the total coincident impacts for all system measured and also extrapolated to all systems that received incentives.

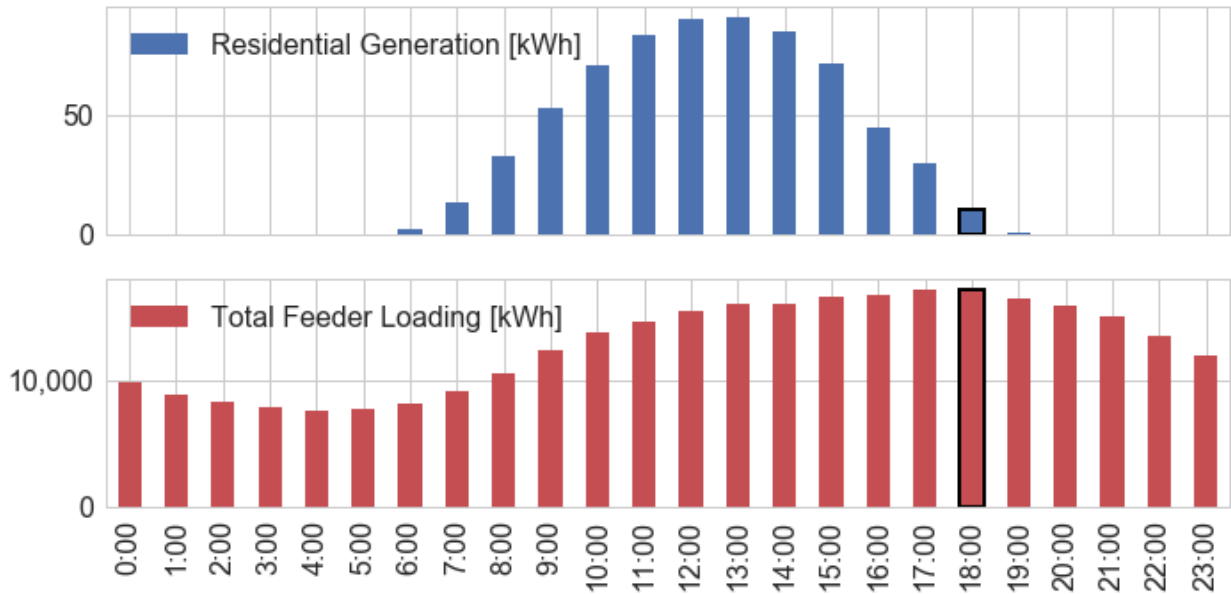
Note that these measured coincident capacity factors are significantly lower than those estimated in the Peregrine Energy report in which the following values were assumed for south, southwest, west and single axis systems: 38%, 43%, 43%, 48%. Therefore, the impact from the systems is lower than what was expected at the outset of the program.

Program Impact on Reducing Max Loading Hour

Determining the coincident generation is valuable, but a key object of this program was to evaluate the potential for PV power generation to reduce the power demand during the maximum loading hour of the year. This is important because loads on highly-loaded feeders could potentially surpass the rated capacity of distribution equipment during periods of maximum peak demand. This can reduce the life of certain infrastructure, such as distribution system transformers, which may experience acceleration of degradation of cellulose and oil at higher loadings and temperatures. National Grid should consider further work to leverage IEEE C57 standards concerning transformer health to estimate the extension in

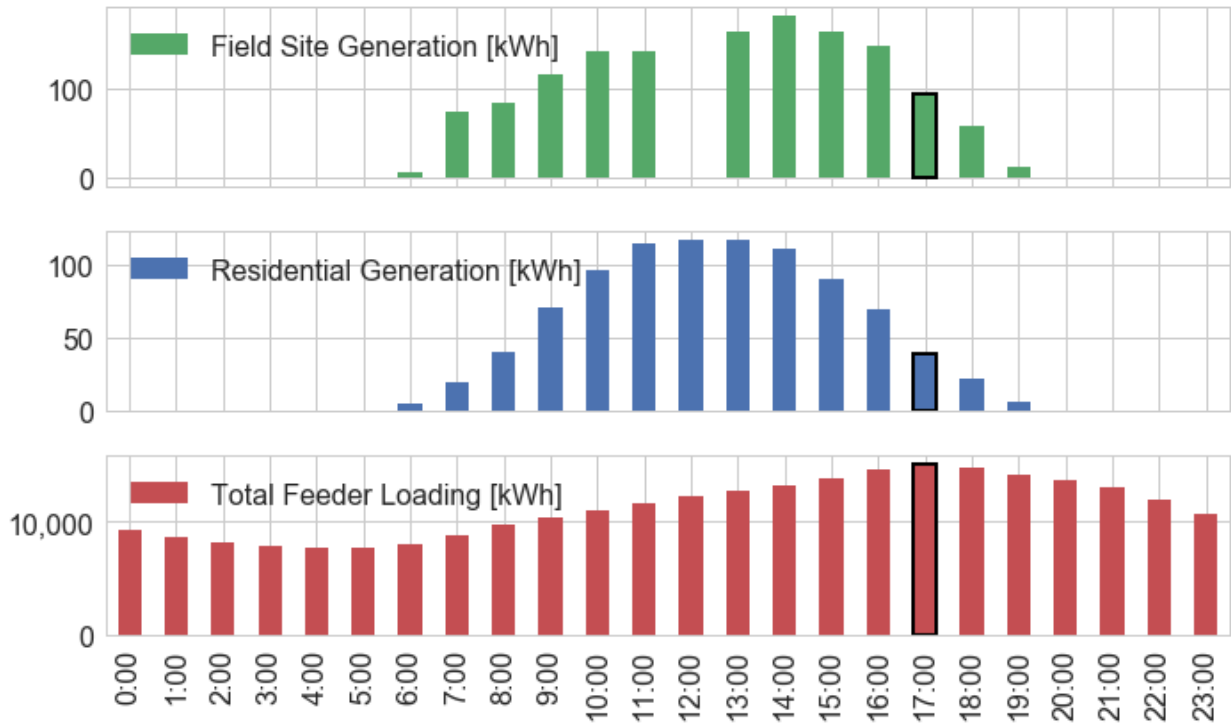
equipment life realized by reducing load, which this is out of scope for this report. Short of this, Cadmus determined the peak loading hours for both summers of 2016 and 2017 and determined power generation from the PV resources. Figure 6 and Figure 7 depict the hourly generation and loading values throughout both these days from 2016 and 2017. In 2016, the day was overcast and relatively little of the installed solar resources' capacity was available for generation during the max loading hour. During that hour, 10.61 kWh on average was generated. In 2017, the capacity factors for the systems were greater than during the previous year, with 133.65 kWh generated during the max loading hour.

Figure 7. Generation of the Rooftop-Mounted Fleet and Energy Load for the Max Loading, 2016*



* 6 p.m. to 7 p.m. on August 14, 2016.

Figure 8. Generation (of both the Field and the Fleet) and Energy Load for the Max Loading, 2017*



* 5 p.m. to 6 p.m. on July 21, 2017. Note that the generation data from the field site during the noon hour for this day was not available.

Given that power factor (the ratio of real power to apparent power) was not available for the apparent power measurements taken at the substation, Cadmus applied a common assumption of 0.98. Figure 11 shows the generation of the solar resources and their percentage reduction on the max loading hour for both summers. With the output totals extrapolated to the whole program, it did not achieve the target of 250 kW reduction for either summer.

Table 10. Capacities Installed, Capacity Factor During Max Loading Hour, Total Output During Max Loading Hour, and Percentage Reduction in Feeder Loading (2016 and 2017)

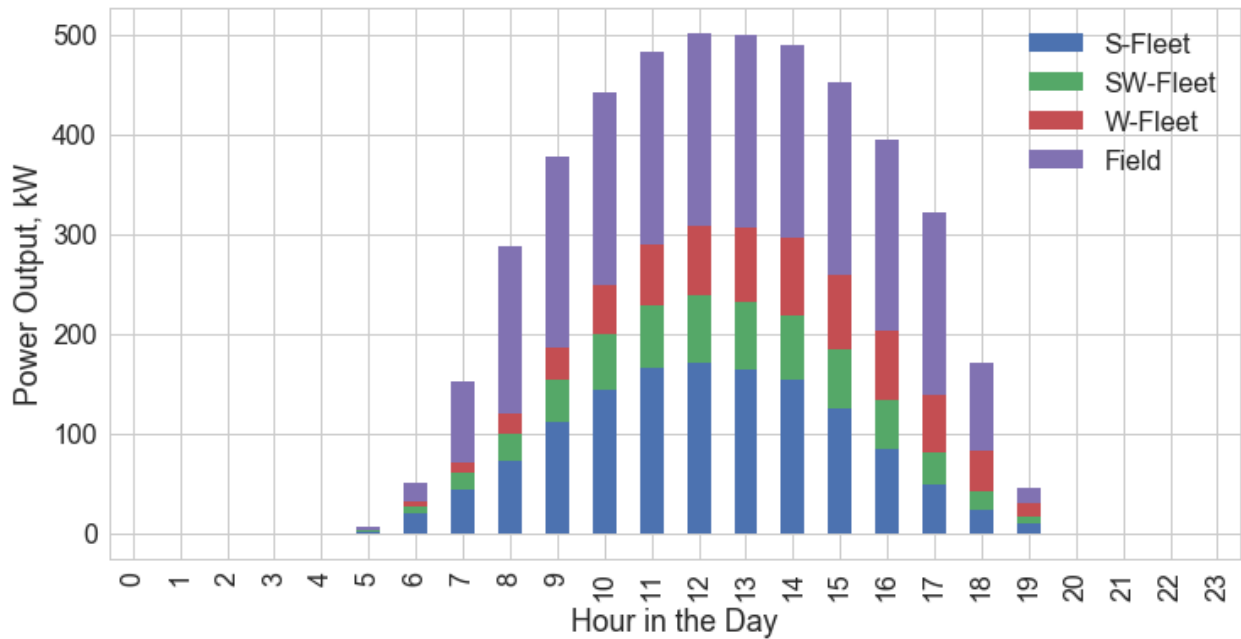
System Type	Orientation	Summer 2016, Max Hour of 17.5MWh				Summer 2017, Max Hour of 15.4MWh			
		Installed Capacity, kW-DC	Capacity Factor, kW-AC/kW-DC	Output at Max Load Hour, kW-AC	Reduction of Max Load	Installed Capacity, kW-DC	Capacity Factor, kW-AC/kW-DC	Output at Max Load Hour, kW-AC	Reduction of Max Load
Roof-Mounted	South	58.7	5%	2.68	0.015%	87.5	15%	13.4	0.087%
	Southwest	39.2	9%	3.59	0.021%	60.1	26%	15.6	0.101%
	West	31.8	14%	4.34	0.025%	30.1	34%	10.2	0.066%
Ground-Mounted	n/a	n/a	n/a	n/a	n/a	249.9	38%	94.6	0.615%
Measured Total		129.7	8%	10.61	0.061%	427.6	31%	133.7	0.869%
Extrapolated to Program*		395.2	8%	30.80	0.17%	645.0	28%	182.1	1.18%

* To estimate the impact of the whole program, residential roof-mounted systems that were not monitored were included such that their generation rate was the same as their azimuth group (i.e., south, southwest, west). For 2016, the ground-mounted system was not included, but all 57 residential systems that were to receive incentives were included. For 2017, the extrapolation also includes the ground-mounted system.

Note that these measured capacity factors during the max loading hour are significantly lower than those estimated in the Peregrine report, which assumed the following values for south, southwest, west, and single-axis systems: 26%, 48%, 55%, and 58%, respectively. Therefore, the impact from the systems is lower than what was expected at the outset of the program.

To get a better understanding of the whole program’s impact throughout the day, we used our extrapolation to investigate power output throughout the day. Figure 8 below shows the maximum power output for every hour during the summer of 2017 for each resource type. The peak power output is above 250 kW from 8 a.m. to 5 p.m., and falls off sharply thereafter. West-facing systems outperform south-facing systems during the hours of 5 p.m. and 6 p.m.

Figure 9. Max observed power generation during the summer of 2017 for each resource type*



* Rooftop-mounted groups are identified in the legend as Fleet and are preceded by their orientation abbreviation.

Cost-Effectiveness of PV to Realize Peak Loading Reduction

Cadmus grouped the incentives given for rooftop systems by the orientation of the systems (south, southwest, and west) to determine each group’s average incentive per solar PV kilowatt DC capacity. This was conducted using both the total value of all state incentives (REF and SRP), as well as isolating only the SRP DG pilot incentive. We then combined these cost values with the mean coincident capacity factor values from 2017 to determine the incentive per coincident load reduction, which can be considered a measure of the cost-effectiveness. The cost for incentivizing coincident load reduction was determined as follows:

$$\frac{\text{Incentive per Capacity}}{\text{Coincident Capacity Factor}} = \frac{\frac{\text{Incentive (\$)}}{\text{Installed Capacity (kW - DC)}}}{\frac{\text{Mean Coincident Output (kW - AC)}}{\text{Installed Capacity (kW - DC)}}} = \frac{\text{Incentive (\$)}}{\text{Mean Coincident Output (kW - AC)}}$$

As shown in Table 11, while west-facing systems received more financial incentives from the SRP DG pilot on an installed capacity basis, this allowed the total incentive to be comparable across all orientations when normalized by the coincident demand. The SRP incentive was specifically calibrated to account for reduced total generation. It was therefore successful in enrolling west-facing systems while maintaining a comparable cost of coincident load reduction across orientations.

When analyzing just the SRP incentive, south-facing systems offered the most demand reduction per dollar spent by the program. As most of the incentive was comprised of the REF funding, the incremental \$70 per kW-DC capacity installed for south-facing systems was dramatically lower than the

\$480 per kW-DC awarded to west-facing systems. The SRP incentive was also meant to offset lower total generation, which increased the total incentive for more western systems.

Table 11. Average Incentive Per DC Capacity Paid for Residential Systems and the Cost-Effectiveness of Demand Reduction Realized During Coincident Hours

System Type	Orientation	Number of Systems Received SRP	SRP Incentive Only		Total Incentive (SRP + REF)	
			Given to System Owners per PV Capacity Installed [\$/kW-DC]	Cost to Reduce Coincident Load [\$/kW-AC]	Given to System Owners per PV Capacity Installed [\$/kW-DC]**	Cost to Reduce Coincident Load [\$/kW-AC]
Roof-Mounted	South	3	\$70	\$337	\$1120	\$5400
	Southwest	12	\$278	\$1055	\$1360	\$5160
	West	16	\$480	\$1683	\$1490	\$5224
Ground-Mounted*	Single Axis	1	\$740	\$2310	\$740	\$2310

* The owner of the ground-mounted system received a SRP grant of \$185,000. This is normalized by the kW-DC capacity of the system to determine a comparable incentive to the roof-mounted systems.

** Beyond the SRP specific funding, all rooftop-mounted systems received REF funding. The ground-mounted system also received a 20-year fixed tariff payment through the Renewable Energy Growth program, which is not captured in this table.

Cadmus determined PV deployment capacities needed to reduce average loading during coincident hours by various target percentage amounts: 5%, 10%, and 15% average loading reductions. We selected these targets as representative values given the size and loading profile of the feeder. By dividing the target loading reduction by the mean coincident capacity factors for each system group, we determined the resulting required capacity sizes. The sizes, listed in Table 12, give the estimated system sizes needed to produce the *mean* target load reduction during the coincident peak hours (all occurring before 8 p.m.). Further analysis would be necessary to determine the required capacity to realize reduction targets tied to specific reliability criteria.

Table 12. Estimated Deployment Scales Needed for Solar Resources to Lead to 5%, 10%, and 15% Average Loading Reduction During Coincident Hours for 2017*

System Type	Orientation	PV Capacity for 5% Reduction (0.58MW) during Coincident Hours, MW-DC	PV Capacity for 10% Reduction (1.16MW) during Coincident Hours, MW-DC	PV Capacity for 15% Reduction (1.74MW) during Coincident Hours, MW-DC
Roof-Mounted	South	2.8	5.6	8.4
	Southwest	2.2	4.4	6.6
	West	2.0	4.1	6.1
Ground-Mounted	Single Axis	1.8	3.6	5.4

* Deployment scales were estimated by dividing the target reduction (i.e. 0.58, 1.16 and 1.74 MW) by the coincident capacity factors for each resource group from 2017.

As discussed earlier, using the information on incentives provided to customers for installing systems at various orientations, we determined the cost-effectiveness of the pilot incentive for reducing peak loading during coincident hours, shown in Table 11. When considering only SRP incentives, south-facing systems were much a much more cost-effective strategy to reduce peak load. However, utilizing the SRP incentive also allowed for near cost parity when considering the total incentive offered to pilot participants (both SRP and REF funding) to reduce peak load, regardless of system orientation. Table 13 lists the total estimated cost of incentivizing the different system orientations to achieve the various levels of coincident load reduction. Both the total incentive and the SRP-specific incentive are shown. The ground-mounted system would receive the most funding from the SRP program of all resources types.

Table 13. Estimated Incentive Costs in Millions of Dollars to Realize Reductions in Coincident Load*

Orientation	Estimate Cost for 5% Reduction Coincident Load [\$MM]	Estimate Cost for 10% Reduction Coincident Load [\$MM]	Estimate Cost for 15% Reduction Coincident Load [\$MM]
South	\$0.20 (\$3.1)	\$0.39 (\$6.3)	\$0.59 (\$9.4)
Southwest	\$0.61 (\$3.0)	\$1.2 (\$6.0)	\$1.8 (\$9.0)
West	\$0.98 (\$3.0)	\$2.0 (\$6.0)	\$2.9 (\$9.1)
Single Axis	\$1.3	\$2.7	\$4.0

* Total incentives beyond those given directly from the SRP program are shown in parentheses.

Deploying Storage to Reduce Max Feeder Load

Given the low capacity factors of the PV systems during the max loading hour, Cadmus undertook an extra hypothetical exercise to explore how energy storage could be used to reduce peak loading on the feeder. Because of the overall feeder peak loads occurring late in the day, energy storage may provide a cost-effective way to manage peak demand—either on a standalone basis or in combination with solar PV. When combined with solar PV, energy storage can be more cost-effective due to the ability to capture the 30% federal Investment Tax Credit on the cost of the storage equipment, whereas this benefit would not be available for standalone storage projects.

As an initial analysis, storage systems were sized to realize a 5% reduction during the max loading days from 2016 and 2017. For 2016, this would require 875 kW of power capacity and 2.67 MWh of energy capacity, while the requirements would be 768 kW and 1.54 MWh in 2017. Assuming that storage was deployed in a distributed fashion on customer sites with two-hour, 5 kW systems, then 268 units would have been needed for 2016, and 154 units for 2017. These unit capacities are comparable to the residential products offered by Tesla and Sonnen. If a four-hour storage system was deployed in a centralized fashion (e.g., near a ground-mounted PV system), then energy capacity of the system would be sufficient to shave the max loading. Therefore, the power capacities would need to match the target reduction for 5% reduction: 875 kW for 2016 and 768 kW for 2017.

As of November 2017, National Grid planned to install a 1 MWh four-hour, 250 kW energy storage system in Little Compton capable of providing 250 kW of peak load relief for 4 hours. Under these sizing

specifications, the energy storage system would have been able to realize a 1.4% reduction in max loading in 2016, and a 1.6% reduction in 2017.

Conclusion

The SRP DG pilot deployed orientation-prioritized distributed generation systems that shifted generation to better offset peak feeder load. We confirmed that the generation profile for the west-facing systems was higher later in the day than south-facing systems and was more coincident with peak loading on the substation. The pilot's success varies from year to year, depending on the nature of the summer demand curve and weather. This can quickly be summarized with the peak loading hour of each analysis year. In 2016, the peak loading hour from 6 p.m. to 7 p.m. on August 14 ended just 45 minutes before sunset that day which occurred at 7:45 p.m. In 2017, the peak loading hour was July 21 from 5 p.m. to 6 p.m. This was more than two hours before sunset at 8:15 p.m., and the SRP DG pilot arrays were still able to produce power with west-facing systems offering the most effective demand reduction on a per-unit-installed basis.

If a town were simply interested in offering a residential Solarize campaign for load offset, it would still realize benefits. To maximize impact, the distribution of incentives should emulate those in the SRP DG pilot. Based on our analysis in Table 11 above, the cost-effectiveness of reducing peak loading hours was equivalent across orientations for roof-mounted systems.

The SRP DG pilot does illustrate the inherent issues of PV as the sole generating resource when used as a demand management tool, particular for high loading hours occurring after sunset. By facing system westward, PV's generation profile can be shifted to later in the day, but is ultimately still limited by available solar resource. Additionally, the inherent variability of solar generation makes its demand reduction impact inconsistent and will not reliably provide power during the max loading hour. To achieve more consistent demand offset, a battery storage component of the pilot project would be beneficial.

Appendix A. Solarize Survey

MEMORANDUM

To: Danny Musher, OER
From: Cadmus
Subject: PV Customer Online Survey Results Memo
Date: January 5, 2017

The Rhode Island Office of Energy Resources (OER) contracted with Cadmus to research the current market for residential solar electric programs to better understand participation, customer satisfaction, and program processes to make meaningful, actionable recommendations for improvements. This memorandum describes Cadmus' findings, conclusions, and recommendations from the online customer survey and is intended to inform OER's future program marketing planning, strategies, and activities.

Research Objectives

Cadmus worked with OER to identify objectives for the survey of participants on the effectiveness and efficiency of the Solarize campaigns, including these:

- Determine customer communication and satisfaction
- Evaluate response to marketing, messaging, and sales
- Assess interaction with Sol Power and solar ambassadors
- Understand the Solarize campaign from the perspective of residents

Online Survey Methodology

Cadmus developed and implemented a web-based survey for customers in the SRP database. We sent a survey to the census of Solarize program participants with valid e-mail addresses (56 total). A total of 24 customers completed the survey, providing a response rate of 43%. The survey addressed the following topics:

- How they learned about the Solarize program
- Marketing content and outreach channel preferences
- Action taken since participation
- Satisfaction levels overall and with the key elements
- Factors that influenced participation in the Solarize program and the EnergyWise/DemandLink programs
- Motivators and barriers

To support a high response rate for the small census, we followed Dr. Don Dillman's Total Design Method (TDM),¹¹ a comprehensive design and implementation approach routinely used at Cadmus to

¹¹ Dillman, Don A., Jolene D. Smyth, and Leah Melani Christian. *Internet, Mail, and Mixed-Mode Surveys: The Tailored Design Method*. Wiley and Sons, 2009.

produce highly valid data. We used these key TDM aspects for web surveys: made participation convenient and brief with focused questions; personalized all contacts with respondents; offered an incentive (\$100 gift card) to one randomly selected respondent as a token of appreciation after survey completion; and used multiple contacts, prompts, and follow ups. We used Qualtrics, an online survey firm, to administer the surveys. We designed the survey web-based survey to be completed in less than 15 minutes. The average survey completion time was 13 minutes.

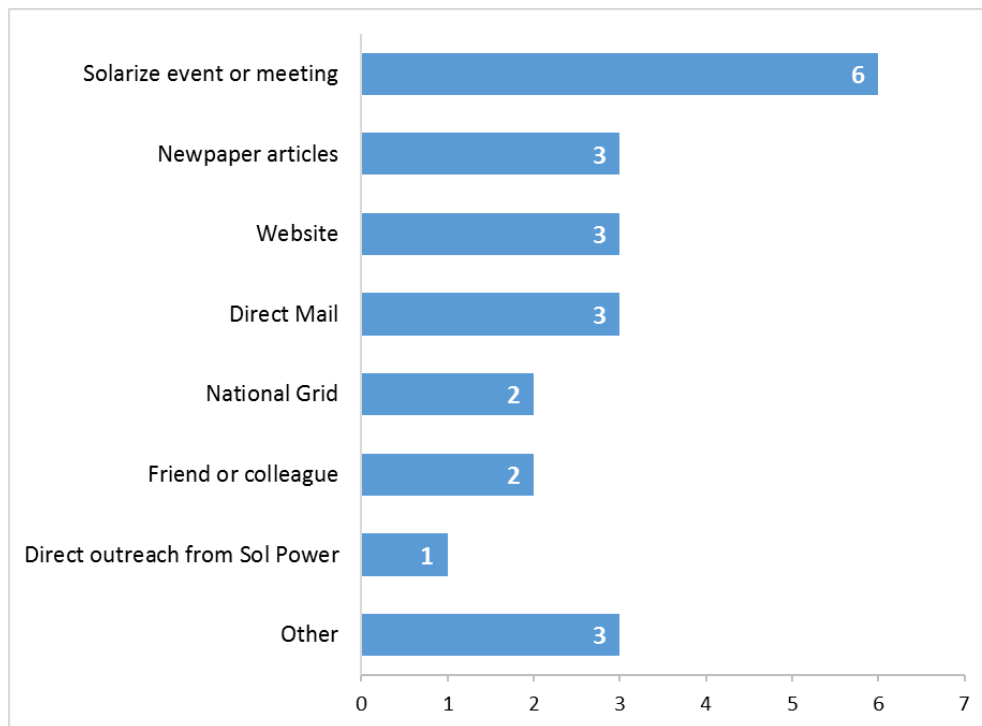
Findings

This section presents detailed study findings from the participant online survey. Of the census (n=56) with valid e-mail addresses, 24 participants completed the survey.

Sources of Learning for the Solarize Program

Among all survey respondents, the most common way they first learned about the Solarize program was through a Solarize event or meeting (n=6), follow by newspaper articles (n=3), websites (n=3), and direct mail (n=3). Figure 10 details how respondents first heard about the Solarize program.

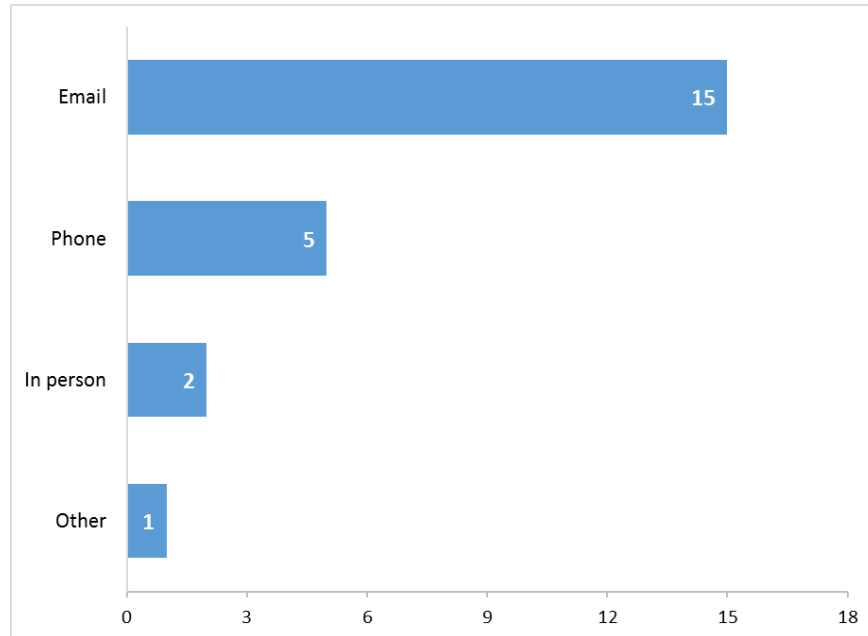
Figure 10. How Respondents First Heard of the Solarize Program



Of the respondents that first became aware of the Solarize program through a Solarize event or meeting (n=6), all stated that the meeting was informative and beneficial to their decision to pursue a solar PV installation. We followed up by asking those same respondents what about that in-person interaction was beneficial. One respondent stated, "[I was] impressed with [the] presenters." Another respondent said, "met the installers." The other respondents cited the value of being able to ask questions and the value of the information provided.

Cadmus asked participants what was the best method to communicate with them in the future. As shown in Figure 10, over half of the respondents (n=15) stated that they preferred e-mail, while some preferred a phone call (n=5) or an in-person visit (n=2).

Figure 11. Preferred Communication Methods

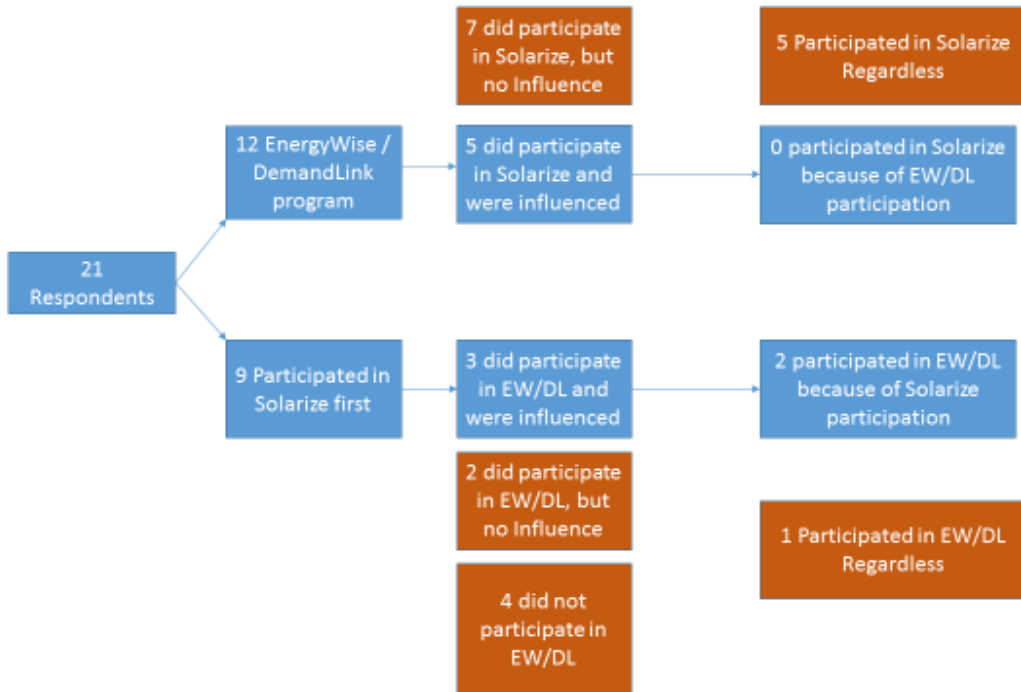


Next, we asked survey respondents if they learned about the Solarize program through the EnergyWise/DemandLink program first, and if so, how much influence that program had on their decision to participate in the Solarize program, or vice versa. Of the respondents (n=21), twelve stated they first found out about the EnergyWise/DemandLink program first, while nine found out about the Solarize program first.

As shown in Figure 11, four of the nine participants who found out about the Solarize program first did not participate in the EnergyWise/DemandLink program, while two stated that their participation in the Solarize program was not influential in their decision to participate in the EnergyWise/DemandLink program. Of the remaining three participants, two stated that the Solarize program was influential to participating in the EnergyWise/DemandLink program, while another stated the program was not very influential. In short, two of the nine participants were influenced to participate in the EnergyWise/DemandLink through participation in the Solarize program.

All 12 respondents who first found out about the EnergyWise/DemandLink program also participated in the Solarize program, although seven of those 12 were not influenced by their participation to join in the Solarize program. Finally, five respondents stated that they would have participated in the Solarize program regardless of their participation in the EnergyWise/DemandLink program.

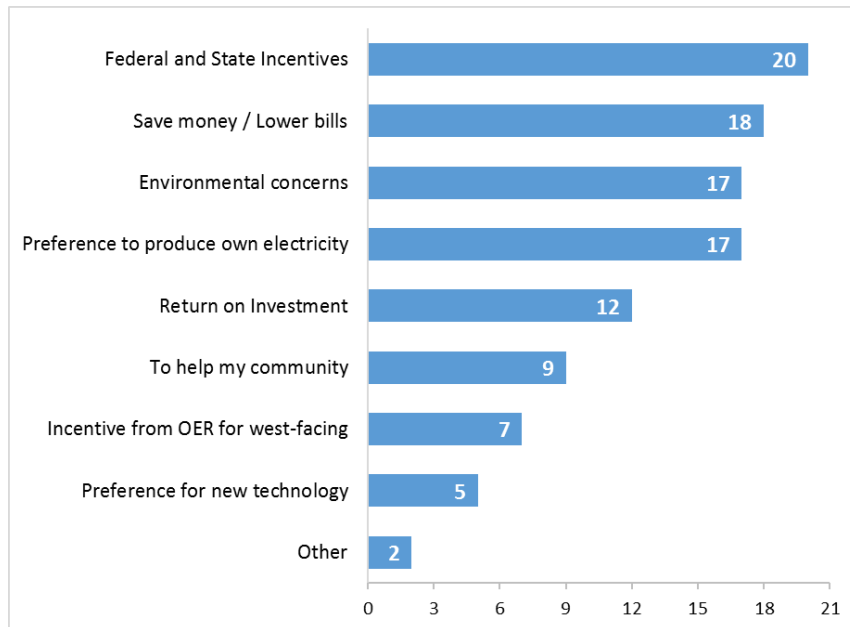
Figure 12. Influence from Participation in Solarize or EnergyWise/Demand Link Programs



Customer Motivations and Barriers

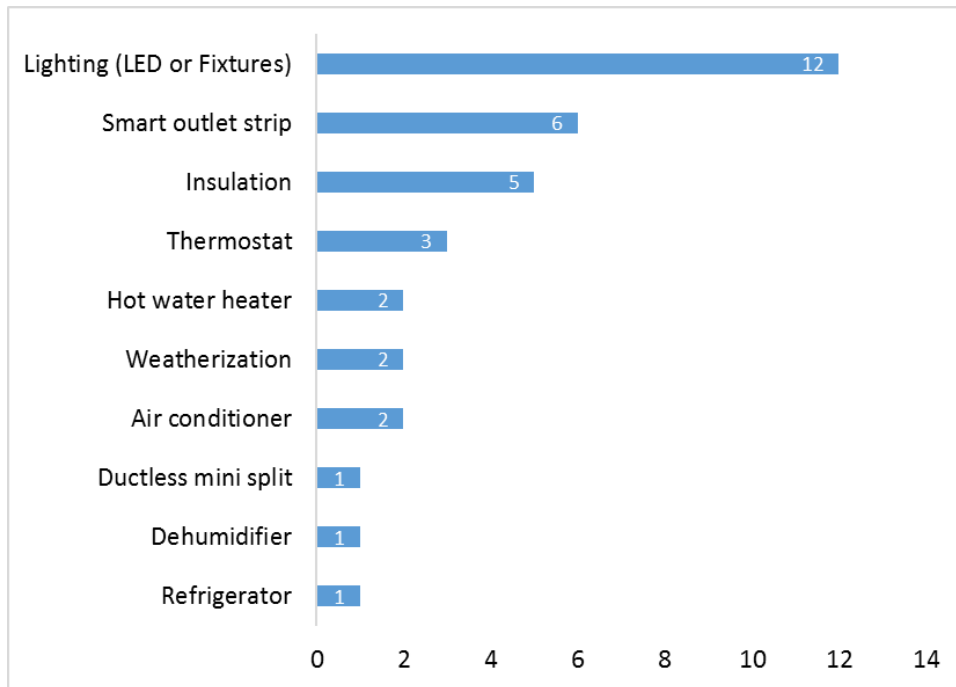
When asked what their main reasons were for participating in the program and installing a solar PV system, respondents could provide multiple answers. The top response, as shown in Figure 12, was the federal and state incentives (n=20). Other popular responses included saving money by lowering the energy bill (n=18), environmental concerns or benefits (n=17), and producing one’s own renewable electricity (n=17).

Figure 13. Reasons for Wanting a Solar Electric System



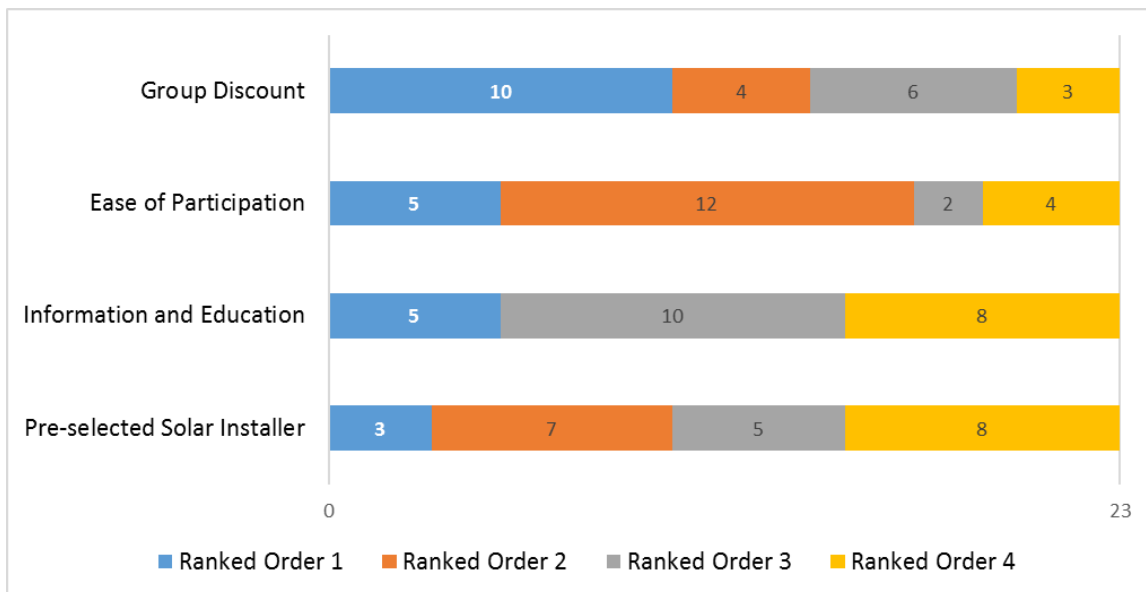
When asked if they had participated in the National Grid EnergyWise program, nearly all of the respondents (21 of 23) stated that they did participate in the program. We also asked respondents if they had participated in the National Grid DemandLink program for Tiverton and Little Compton customers. Respondents were split (n=18), with nine reporting yes, and nine reporting no. We then asked respondents to list the energy efficiency recommendations that they have implemented since participating in the EnergyWise program. Of the respondents (n=20), well over half (=12) stated that they had installed either LEDs, new lighting fixtures, or both. Six respondents said they installed a smart outlet strip, and five said they added insulation. Figure 13 provides further details on the energy efficiency recommendations that the respondents have implemented since participating in the Solarize program (multiple responses per respondent allowed).

Figure 14. Energy Efficiency Recommendations Implemented Since Program Participation



Cadmus asked participants to rank the importance that several elements had on their decisions to install their solar PV system. As shown in Figure 14, the group discount was the highest ranked program element, with 10 respondents ranking it as the most important.

Figure 15. Importance of Program Elements



West-Facing Solar PV Incentive

Cadmus asked respondents if they were aware of the extra incentive for installing a west-facing solar PV system. The majority of the respondents (20 of 23) stated that they were aware of this incentive. We followed up by asking respondents if this extra incentive was an important factor in their decision to install a solar PV system. Respondents were nearly split (n=19), with 10 stating either *very important* or *somewhat important*, and nine stating *not very important* or *not at all important*.

We further investigated these responses by using google earth images to determine the number of respondents with roofs appropriate for west-facing solar PV systems and found a 50/50 split—11 of the respondents' roofs were not suitable for a west-facing PV system, while 11 may have the space and orientation that would lend itself to a west-facing system. (We could not verify one address for this exercise.)

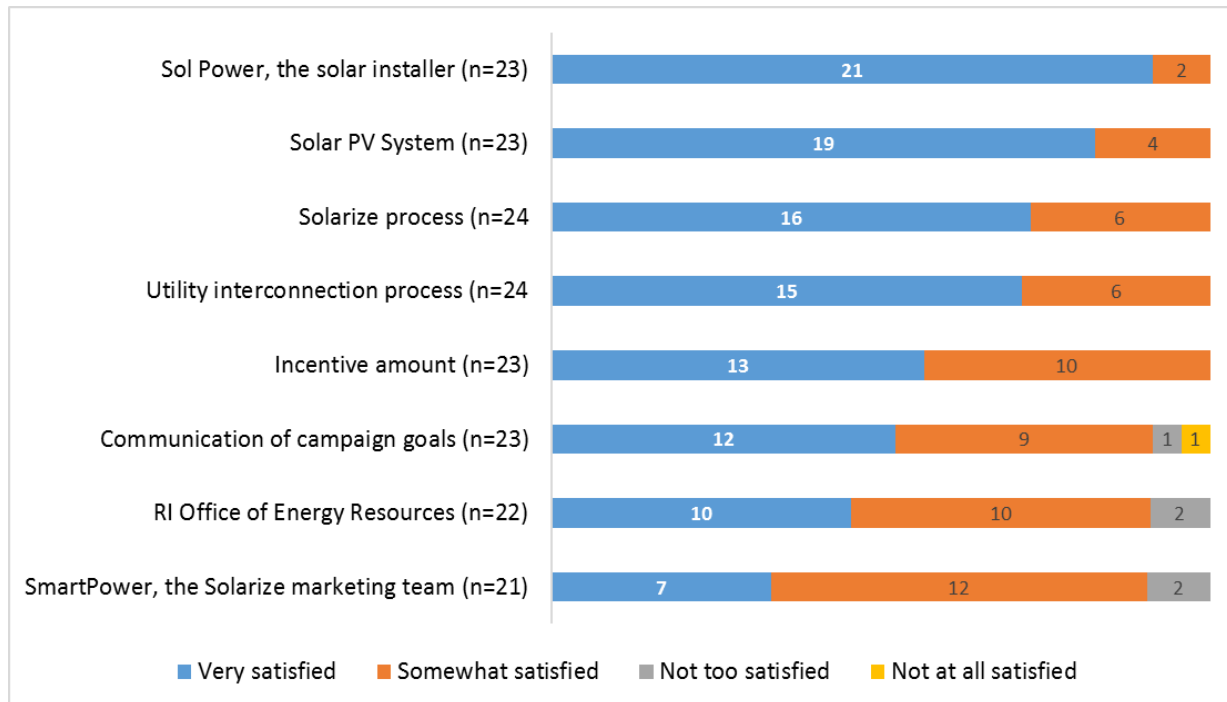
Of the respondents who did not have a west-facing roof, six did not find the incentive important, whereas three found the incentive important. One participant did not know about the incentive, and another did not answer.

Of the respondents who did have a west-facing roof, three did not find the incentive important, whereas seven found the incentive important. One participant did not know about the incentive, and therefore did not answer the question.

Customer Satisfaction

Cadmus asked respondents how satisfied they were on various components of the program. Nearly all respondents expressed satisfaction with the program components, indicating either *very satisfied* or *somewhat satisfied*. The highest rated component was with the installer, Sol Power, with 21 of 23 respondents stating they were *very satisfied*. Other highly ranked components included the Solar PV system itself (with 19 of 23 stating *very satisfied*) and the Solarize process (with 16 of 24 stating *very satisfied*). A few respondents were dissatisfied with some program components, including OER (n=2), SmartPower, the Solarize marketing team (n=2), and communication of campaign goals (n=2). Figure 15 shows all of the responses by program component.

Figure 16. Satisfaction with Program Components



Cadmus asked respondents if they have had any problems with their solar PV system. Of the respondents (n=23), three-quarters said there were no problems, while a quarter reported various types of problems. One respondent reported a problem with an inverter, and two reported problems with the panels themselves. Another respondent reported a problem with the electrical system or wiring, another had a problem connecting to the grid, and another had a problem viewing data on the internet or application. Of those six respondents, all but one said that the problem was fixed by the installer. The remaining respondent still needed to fix the problem.

Demographics

Cadmus asked several questions to gain a better understanding of the respondents’ demographics. Of 23 respondents, the average year of birth was 1951. Education level was dispersed. Of 22 respondents, nine completed a graduate or professional degree, six completed a four-year degree, three completed a technical degree, two completed some college courses, and two completed high school.

We also asked respondents about features in their homes. All respondents (n=23) stated that they lived in a single-family detached home. Of the 23 respondents, over half (n=15) stated that the primary fuel used to heat their home was oil, while only two respondents use electricity, four use propane, and two use wood stoves or pellet. We also asked what type of fuel the respondents’ water heater uses. Over half (12 of 23) use an oil burner that supplies hot water directly, while four use electricity, and seven use propane.

Finally, we asked what methods respondents use to cool their home. Nearly half (10 of 23) stated that they use a central air conditioner, while eight said window air conditioning units, and four said ductless mini-split systems.

Appendix B. Solarize Incentive Methodology

Solarize Tiverton & Little Compton – Solar for Distribution Grid Support

Introduction to the Peaking Rebate

Rhode Island’s regular solar program provides a standard incentive to system owners who have eligible solar projects. There is a screening test, based on tilt/azimuth and shading, to determine site suitability.

This Solarize program in these two towns is designed to offer an additional rebate to more west-facing systems whose total *annual* solar output may be lower than optimal but who contribute beneficially during the period of highest utility demand, during summer late afternoons.

This Peak Rebate offering has two components:

- For those sites that are suitable, an additional “Peaking Rebate” based on tilt/azimuth and afternoon shading.¹²
- Different screening test(s) for southwest and west-facing systems.

The additional Peaking Rebates are based initially on the following table. The Solarize contractor will determine the tilt and azimuth angles for your solar system and look up the incentive number in Table 1. The ranges are to be interpreted as “greater than the lower angle and up to and including the higher angle.” The rebates will then be further adjusted for summer afternoon shading as described below.

	az 190-200	az 200-210	az 210-220	az 220-230	az 230-240	az 240-250	az 250-260	az 260-270	az 270-280
tilt 0-10	\$169	\$187	\$204	\$219	\$229	\$237	\$243	\$246	\$247
tilt 10-20	188	244	295	340	374	401	419	430	431
tilt 20-30	89	129	188	263	351	450	557	576	579
tilt 30-40	27	77	147	238	344	460	586	662	665
tilt 40-50	55	106	187	280	388	509	640	704	708
tilt 50-60	0	177	294	385	489	591	698	723	727

A Peaking Rebate is only available for solar systems with eligible angles for which dollars are listed in this table. For these eligible systems, the regular 80% TRSF screen will not be applied; that regular screen considers tilt and azimuth as well as shading, but tilt and azimuth have already been taken into account by the table of Peaking Rebates. The eligible configurations in the Peaking Rebate table will instead be screened for Solar Access based only on the effect of *shading*; this screen will be based on annual average insolation but the threshold will be higher – 90%. If a system fails this 90% screen for annual

¹² The normal rebate and program procedures continue to apply to traditional, more south-facing systems.

shading, it does not qualify for any Peaking Rebate.¹³ If it passes the 90% screen, it qualifies for the Peaking Rebate (adjusted for shading as described below) plus the regular rebate of \$1.15/Watt, multiplied by the DC size rating of the solar system.

To determine the actual Peaking Rebate for a qualifying system, another Solar Access figure is determined during the three summer¹⁴ peak hours from 4 pm to 7pm, and this percentage is multiplied by the Incremental Distribution Value from Table 2 below for the same tile and azimuth angles. These distribution values have been multiplied by a 90% percentage limit in order that some distribution value should remain for the public or the utility. Once the summer afternoon shading has been assessed, if the dollar amount in Table 2 is lower than the rebate number in the Table 1 above, then this lower value is used for the Peaking Rebate.

	az 190-200	az 200-210	az 210-220	az 220-230	az 230-240	az 240-250	az 250-260	az 260-270	az 270-280
tilt 0-10	\$169	\$187	\$204	\$219	\$229	\$237	\$243	\$246	\$247
tilt 10-20	188	244	295	340	374	401	419	430	431
tilt 20-30	172	267	354	430	486	529	559	576	579
tilt 30-40	137	265	380	480	550	604	642	662	665
tilt 40-50	77	235	377	499	578	638	681	704	708
tilt 50-60	0	177	349	498	584	651	698	723	727

Examples:

- If a system with, for example, 35tilt and 235az passes the 90% shading test, then they start with a \$344/kW Peaking Rebate from Table 1. If however, they have a 50% shading factor during the Peak Period (defined as three hours on summer late afternoons, specifically from 4pm to 7pm), then they receive only 50% of the Incremental Distribution Value, which is \$550 for this tilt and azimuth, 50% of which is \$275/kW. So the contractor has to do two shading measurements: annual average shading to qualify for Solarize participation; and peak period shading to adjust the Peaking Rebate if needed. This is intended to allow a relatively good site to still qualify for the regular base rebate of \$1.15/Watt but if it has one really badly placed tree that would affect its availability during the peak period, then its Peaking Rebate is reduced.
- A SW-facing (225az) system with a tilt angle of 45 degrees, if it meets the Solar Access screen, would start with a Peaking Rebate from the table above of \$280 for each kW of size (dc). If it's Solar Access percentage for the summer hours from 4 pm to 7pm is 85%, due to shading during those hours, then the Distribution Value would be looked up, which for these angles is \$499.

¹³ If a system fails this 90% shading screen, or is not covered by the filled cells in the table above, it does not qualify for any Peaking Rebate, but it may be separately screened using the regular 80% TRSF (tilt/azimuth and shading) to participate in the regular program.

¹⁴ The 4-7pm shading analysis will be performed only for the "summer," which could be defined as either (a) the months of July and August, or (b) the 30 mid-summer days from 7/15 through 8/14.

Since 85% of this is \$424, this would not affect the actual Peaking Rebate, which would be the minimum of that \$424 or the value from Table 1: \$280/kW-dc.

- The Peaking Rebate for a west-facing (270az) system would be higher in the table above, to offset the lower annual output for a west-facing system. If it has a tilt angle of 25 degrees, it would start with 90% of the Distribution Value, which at \$576/kW is lower for these angles than the value of the reduced output relative to a south-facing system. If it's Solar Access percentage from 4 pm to 7pm is 85%, due to shading during those hours, then the actual Peaking Rebate would be that 85% times the Distribution Value of \$576, or \$490/kW-dc. This Peaking Rebate would be added to the regular \$1.15/Watt, for a total rebate of \$1,640/kW.

Methodology for Additional Rebate Incentive Table

The Solarize component of the SRP Solar Pilot was designed to achieve a significant distribution contribution by encouraging the enrollment of homes and small businesses with roofs that face more to the west. To do this, incremental rebates were developed that would approximate the present value to homeowners of the reduction in the future savings in their electric bills from solar.

The Peaking Rebates in the table above were designed with the general concept of making the economics of a SW-to-W-facing system roughly equivalent to an “optimal” south-facing system at a 35 degree tilt, despite the lower annual kWh output, under most circumstances. These circumstances generally include azimuth angles less than about 260 degrees with no afternoon shading, or tilt angles greater than 20 degrees, and in such cases, the Peaking Rebate is structured to be worth today approximately what the reduced output would be worth over the next 25 years.¹⁵

More specifically, the amount of these rebates are based in part on calculations of the annual solar generation that would be reduced as a result of shifts from a due-south orientation (180 degrees azimuth, 35 degree tilt) through a due-west direction (270 degrees), and as a result of tilt-angle variations between 0 and 60 degrees, using the PVWatts calculator at pvwatts.nrel.gov. For example, a 1kW fixed array facing south-west (225 degrees) with a 30-degree tilt angle would “lose” about 75 kWh/year compared to a standard due-south orientation, a reduction of 5.5%. If the southwest-facing system also has a steeper tilt angle of 50 degrees, this would be a further reduction of about 30 kWh/year, so the rebate for this “50-225” system is designed to compensate for a reduction of 105 kWh/year compared with the more standard “30-180” system.

The amount of these rebates are also based on the assumption that the output of the solar system will not exceed the electricity usage of the home during the period over which these quantities are totaled for billing purposes. As a result, each kWh of output that is reduced on an annual basis due to improving

¹⁵ Since a Solar Access shading factor between 4-7pm is used to reduce the level of actual Peaking Rebate, then program messaging should not emphasize these economics of reduced output, or the residential customer should be advised when the rebate would **not** likely cover the economic value of the reduced output compared with a South-facing system. In any case, each customer should analyze the economics of their own system once all the screens and incentives have been applied.

the output of the solar system during the period of highest utility demand is valued at 15.78 cents/kWh in 2015. This is almost the whole retail rate paid by the customer, including the Distribution Charge (3.821 cents), the Transmission Charge (2.221 cents), the Transition Charge (.096 cents), the RES charge (0.48 cents for renewable energy), and the Standard Offer charge for supply of electricity.¹⁶ The average Standard Offer charge for 2015 was estimated to be 9.162 cents; this is based on 10.248 cents for January through June, and for the last six months of 2015, the rate of 7.879 cents from July through December 2014 was escalated by 2.5%.

The 2015 rate is escalated at 2.5%/year for 25 years through 2039, while the solar output is assumed to degrade each year by 0.5%, and the resulting future values are discounted by 4.6%/year to compute a present value for the whole period.

The rebate amounts are also based on the principle that if summer afternoon shading reduces the value of a particular solar installation to the distribution system, then the rebate should be reduced accordingly. This is discussed in the next section.

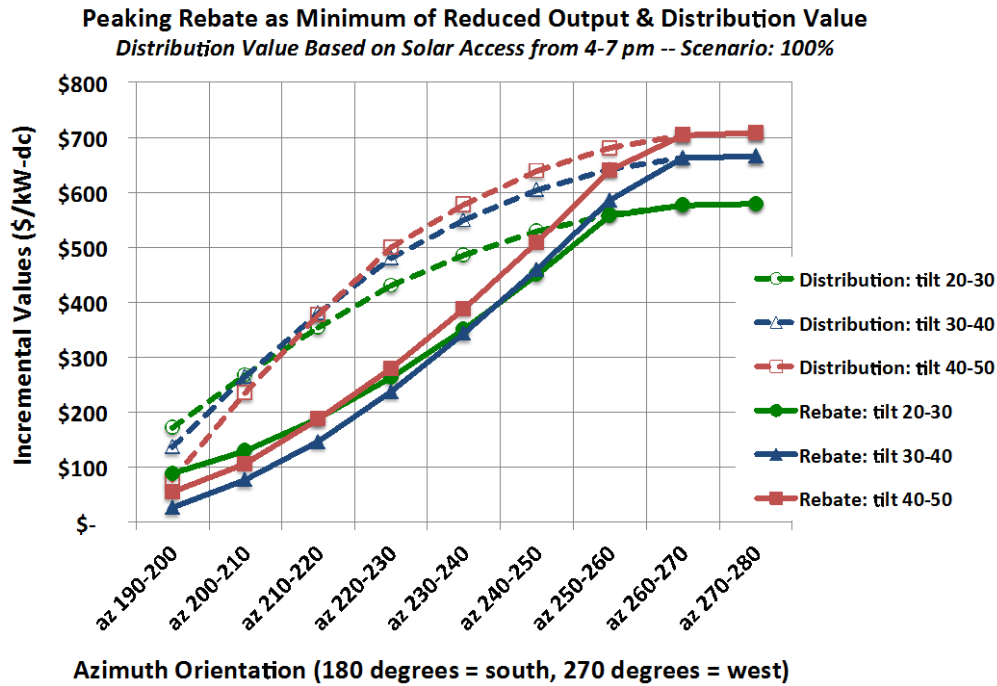
Comparison of Additional Rebates with Distribution Value

The 2014 report estimated the incremental distribution values of different azimuth orientations moving from the south to the west, based on a comparison of (a) the hourly load on the relevant portion of the distribution system (“feeder 4”) for each hour of the 3-year period 2011 through 2013 with (b) the solar output that would have been achieved in each of those hours given actual historical conditions, resulting in the “Distribution Contribution Percentage” (DCP) for each azimuth orientation. The DCP values in that report were not changed for this update of the rebate levels. What is new is estimation of the incremental distribution values of different tilt angles. For each PVWatts run described above, a metric was calculated as a proxy for the DCP: the PV output percent for the hour¹⁷ from 5:00 pm to 6:00 pm EDT, averaged across the 30 mid-summer days from 7/15 through 8/14. This metric was used to interpolate the DCP values from the 2014 analysis to each tilt angle and each azimuth orientation.

The resulting incremental distribution values are plotted in the following chart, in comparison to the rebate levels. This chart illustrates a scenario in which the Solar Access is 100% during the peak summer hours of 4-7pm:

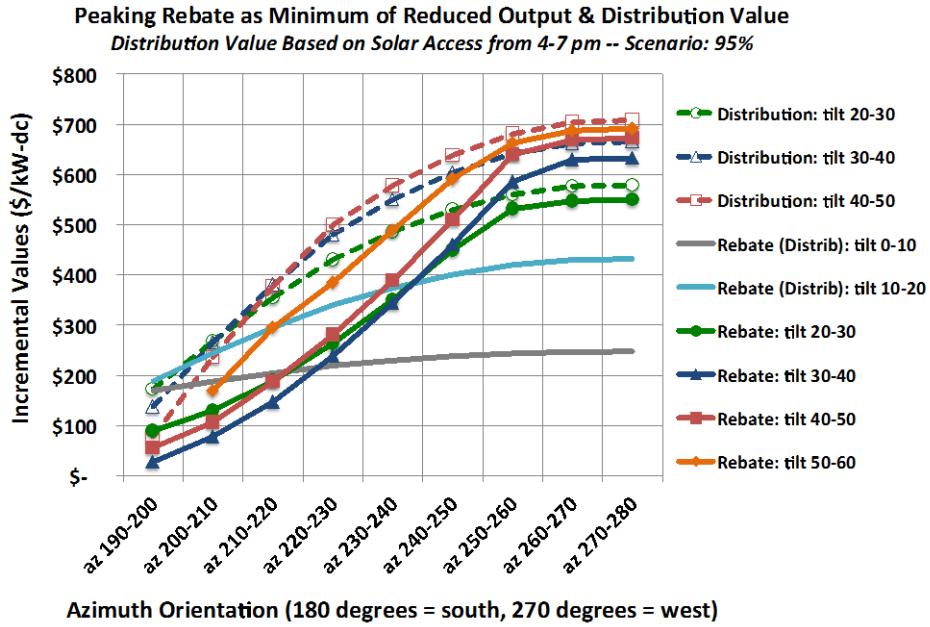
¹⁶ Differences in the output of the solar system will not affect the customer’s costs for the Customer Charge, LIHEAP Charge, Renewable Energy Distribution Charge or Energy Efficiency Programs Charge.

¹⁷ As stated in the 2014 report “The highest peak load on feeder 4 in the three year study period occurred on July 22, 2011 in the hour ending 18 EDT (from 5:00 pm to 6:00 pm).”



The next chart adds some additional tilt angles, as well as assuming that the Solar Access is 95% during the peak summer hours of 4-7pm:

- The rebates for the shallower tilt angles, 0-10 degrees (gray line) and 10-20 degrees (light blue line) are equal to 90% of the Distribution Value, since this is lower than the value of reduced output. The base for the reduction of output is a tilt angle of 35 degrees, and the reduction in output due to the shallower angles is significant.
- The rebates for the steeper tilt angle, 50-60 degrees (orange line with diamonds), are equal to 90% of the Distribution Value for azimuth angles below 210 degrees and above 250 degrees. However, they are based on the value of reduced output from 210 through 250 degrees.



The following chart illustrates, for a solar system with a tile angle between 20 and 30 degrees, how the rebate would be reduced as a result of shading. For the higher azimuth angles, if there is increased shading and lower Solar Access between 4-7pm, the rebates are reduced accordingly so that they are no greater than 90% of the value to the distribution system.

