Celia B. O'Brien
Assistant General Counsel and Director

October 9, 2015

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4568 – The Narragansett Electric Company d/b/a National Grid
Review of Electric Distribution Rate Design Pursuant to R.I. Gen. Laws § 39-26.6-24
Responses to NECEC Data Requests – Set 1

Dear Ms. Massaro:

On behalf of National Grid[1], I enclose ten (10) copies of the Company's responses to the first set of data requests issued by New England Clean Energy Council (NECEC) on September 18, 2015 in the above-referenced docket.

Thank you for your attention to this transmittal. If you have any questions concerning this filing, please contact me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

Enclosures

cc: Docket 4568 Service List
Leo Wold, Esq.
Karen Lyons, Esq.
Steve Scialabba

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

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Joanne M. Scanlon

October 9, 2015
Date

Docket No. 4568 National Grid's Rate Design Pursuant to R.I. Gen. Laws Sec 39-26.6-24
Service List updated 10/2/15

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NECEC 1-1

Request:

In Response CLF 1-1, the Company states that: "Customers who are participating in the Renewable Energy Growth Program and have two meters will be placed into the appropriate tier based on the gross consumption reflected on the meter that measures the customer's on-site use. Customers that have a single net meter will be placed in the appropriate tier based on net consumption." Besides the availability of metering, is there a distinction that warrants different treatment of net-metered and REG Program customers?

Response:

From a cost allocation and rate design perspective, net metering customers with behind the meter generation and Renewable Energy (RE) Growth Program customers with on-site load are similar types of customers. However, net metering and the RE Growth Program are two distinct statutory programs that differ with respect to metering. Section 18 of the RE Growth Program statute (R.I. Gen. Laws Chapter 39-26.6) expressly requires owners of medium-, commercial-, and large-scale solar projects and other DG technologies to provide a meter, at their cost, and further provides the Company the right to install its own meter for small-scale solar projects if a meter is not supplied by the owner and to recover the installation and capital cost of the separate meters in the annual reconciliation. The net metering statute (R.I. Gen. Laws Chapter 39-26.4) does not provide for the installation and cost recovery of a second meter to measure the customer's on-site use as the RE Growth Program statute does. Therefore, the Company is not proposing at this time to install a second meter on current or future net metering customers. In addition, to install a second meter on the generation alone, as is the case with the RE Growth Program, would require the customer to re-wire the behind the meter generation to be metered separately, which would impose a financial burden on existing net metered customers.

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

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NECEC 1-2

Request:

Has the Company done any evaluation of the value of distributed generation (i.e., benefits) to the distribution grid? If so, please provide the data, assumptions and analysis results.

Response:

For the Tiverton pilot, the Company worked with the OER to hire a consultant to determine how much solar would be required to provide 250 kWs of capacity. The consultant, Peregrine Energy Group, Inc., prepared a report entitled "Solar PV for Distribution Grid Support: The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project" dated June 30, 2014, a copy of which is provided as Attachment NECEC 1-2. The value of the capacity from solar in the study relates specifically to the identified system upgrade in that area being deferred, and does not relate to any system-wide value of transmission and distribution deferral. In addition, the "value" of this deferral has already been used to justify the cost effectiveness of the demand response components of the Tiverton pilot.

The Company's affiliates, Massachusetts Electric Company and Nantucket Electric Company, have begun a project, referred to as Solar Phase II, to test various configurations of solar projects to determine the value they can provide to the distribution system and expect results in early 2017. Please see (http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-01%2f1214ngrdptn.pdf) for the proposal submitted to the Massachusetts Department of Public Utilities (the Department) and (http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-01%2fGridSolar140162814.pdf) for the Department's order approving the project (Docket D.P.U. 14-01).

Please be aware that the work the Company describes above has yet to yield actual quantifiable results that can be applied throughout the Company's service territory. These pilots will provide a rich source of information that the Company can analyze to determine the services provided by the generation and the potential savings in cost from the use of those services. In addition, it will provide insight into the design of PV generation units to enable delivery of certain services. The Company expects the effect of solar installed in the Tiverton to be part of the combined evaluations that OER and the Company will conduct in the future. The Massachusetts Solar Phase II project is not expected to provide quantifiable results until sometime in 2017.

Prepared by or under the supervision of: Timothy R. Roughan

PEREGRINE
ENERGY GROUP

Solar PV for Distribution Grid Support:

The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project

June 30, 2014

Prepared by
Peregrine Energy Group, Inc.
2 Oliver Street, Boston MA 02109
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Solar PV for Distribution Grid Support:

The Rhode Island System Reliability Procurement
Solar Distributed Generation Pilot Project

Contents

INTRODUCTION AND EXECUTIVE SUMMARY

National Grid and the Rhode Island Office of Energy Resources (OER) have initiated this study to:

1) understand the extent to which solar distributed generation (DG) resources can provide 250 kW of reliable load relief at times of peak demand that could lead to a distribution investment deferral; and
2) gain insight into the associated costs and benefits of using DG resources as part of a distribution system reliability portfolio.

The context for this project is the System Reliability Procurement (SRP) Pilot that National Grid is conducting to assess load relief from energy efficiency and demand reduction in the communities of Tiverton and Little Compton, Rhode Island. [ES-1] This study outlines the potential for a pilot program of installing solar PV for load relief that is additive to and integrated with National Grid's existing SRP Program, but is funded by the OER and not through the existing SRP budget. Loads are more residential in composition here than the statewide or regional averages and therefore peak later on a summer day.

The capability of PV to generate power in the Pilot area is essentially known for each hour of the day during the summer under optimal conditions. The main factors subject to uncertainty for distribution planning are:

- the time of day at which the relevant load will reach its highest peak of the summer,[ES-2] and
- the extent of reduction in PV output that can be expected at that time, primarily due to cloud cover.

<u>Solar Distribution Contribution</u>. This study therefore analyzes the hourly load on the relevant portion of the distribution system ("feeder 4") for each hour of the 3-year period 2011 through 2013. For each of these hours we compared the load with the solar output that would have been achieved given actual historical conditions.[ES-3] Based on this historical data, we developed a method to calculate the Distribution Contribution Percentage or "DCP" of solar PV, to determine the level of solar capacity that would assure that the 250 kW deferral need could be met for the few highest-load summer hours when it is actually required.

The resulting DCP metrics are presented in Figures 7 and 8 on page 8. We used these DCP values to evaluate multiple solar DG configurations for each of the three years for which load data was available.

- *Example*: a solar configuration with a fixed solar array facing 200 degrees (almost southwest) would provide a DCP of 46% of the kW capacity of the array. This means that to provide 250 kW of sustained, reliable load relief, a total of 540 kW of solar would have to be installed (540 kW capacity x 46% DCP = 250 kW deferral).

The 46% Distribution Contribution Percentage in this example for a southwest orientation is substantially better than the 26% DCP of a typical south-facing PV array. The highest Distribution Contribution was 61% for a system with dual-axis tracking.

Cost of Optimizing PV for Distribution Support. To assess the net value of different PV configurations for load relief, one question is whether the value of the distribution deferral benefit from solar PV is greater than the cost of achieving it. The costs and benefits of using these solar DG resources as part of a distribution system reliability portfolio can be analyzed on the basis that the costs would include only the incremental costs of, or lost revenues from, optimizing the solar systems for distribution deferral, and not the base level of cost for a solar array built to maximize energy production. The solar system(s) would likely be owned by private companies or residents, and those private owners would realize the benefits of the energy generation and so would pay the conventional costs of the solar systems.

The cost to achieve the distribution deferral (from fixed-array configurations) is only the incremental cost of lower annual energy generation that results from facing the PV to the southwest (in the example above) instead of the south.[ES-4] This is discussed in Section 2.4, Incremental Incentives to Optimize Distribution Contribution.[ES-5]

- *Example*: in the Tiverton and Little Compton area, each kW of solar capacity will generate approximately 1,463 kWh if it is facing south (180 degrees), but only 1,309 kWh if it is facing 220 degrees – a modest 5% reduction of 74 kWh/year. This cost amounts to $145/kW in present value terms (from Figure 13, page 13, columns E and F).[ES-5]

Distribution Benefits of Solar PV. The analysis of the distribution contributions of solar PV in this geographic area shows the potential for significant economic benefits from deferring the distribution investment that is the target of the SRP pilot.

- *Example*: The incremental benefit of changing the orientation from 180 to 220 degrees, to continue the example above, is estimated to be $652 for each solar kW installed (from Figure 13, column D) -- significantly greater than the $145/kW cost. This benefit is based on the difference between the Distribution Contribution Percentage of 46% for a 220 degree orientation and the 26% DCP for south (an increment of 20%) times the present value of the deferral savings and avoided distribution cost.

Economic Comparison of Solar PV Configurations. The different solar configurations have different levels of benefits for distribution deferral, as well as different levels of incentives to optimize these distribution contributions.

- Tracking configurations have relatively high DCPs in the range of 60%, though their viability for this Pilot in the short term will depend on incremental capital and operating costs that are difficult to predict meaningfully.
- For fixed solar arrays, there are diminishing returns as the azimuth orientation moves toward the west, with smaller and smaller increases in the DCP. At the same time, increasing incentives would be required to offset greater reductions in annual output as orientation nears the west. The highest level of net distribution benefits are obtained from orientations of approximately 220 degrees for residential projects (with DCP of approximately 46%) to 230 degrees for fixed-array commercial projects (with DCP of approximately 49%). These analyses are described in Sections 2.4 (for ground-mounted solar projects and 3.3 (for rooftop PV projects).

Solar Pilot Resource Portfolio. A portfolio was developed as a target for this SRP Solar Pilot or an example of what could be expected. These resources are sized to meet the 250 kW deferral goal based on the ranges of DCP values summarized above, as shown in the table below (Figure 1):

- *Grid Support Solar Field*: one commercial-scale ground-mounted solar project of approximately 280 kW, or greater, addressed in Section 2, providing over half of the deferral goal (approximately 140 kW based on a Distribution Contribution Percentage of 50%), or a small number of projects with the same total size;[ES-5]
- *Solarize Campaign*: a mix of residential PV systems (totaling 160 kW) and small nonresidential rooftop systems (averaging 25 kW), with a total of at least 200 kW and providing approximately 110 kW or more of distribution contribution based on an average DCP of 45%.[ES-6] These 30 to 35 smaller installations, discussed in Section 3, will diversify the portfolio to offset risks such as the possibility that one or more larger solar fields could be delayed in development.

Figure 1: Solar / Storage Resource Portfolio

		1 Grid Support Solar Field(s)	2 Solarize Residential	3 Other Small Projects	4 Total
1	Gross Capacity (kW)	280	160	80	520
2	Average Distribution Contribution Percentage (DCP)	50%	45%	45%	
3	Distribution Contribution (kW)	142	72	36	250
4	Portfolio Allocation	57%	29%	14%	100%

These resources are described further in sections 2 and 3.

PV Procurement for Distribution Contribution. This portfolio can be used as a general guide to procure the most attractive distribution support options for this Pilot by offering incremental rebates designed to incent interested solar developers and owners to design PV systems with high distribution contributions.

- For the Solar Field, a competitive process would provide PV developers the opportunity to submit a bid for a grant to offset the incremental costs of optimizing the distribution contribution. Each bidder would propose a particular PV orientation or tracker configuration for a specific site in the Pilot areas, and would propose a grant amount. A grant would be awarded to the bidder whose bid is scored as providing the greatest net distribution benefit, and that bidder could then develop the PV project for submission in the next round of the DG Standard Contract process.
- For the Solarize Campaign, a rebate would be calculated for each 10 degrees of orientation to the west of south, and offered as an "instant rebate" directly to each of the 30 to 35 participating customers in the Pilot area. For purposes of this pilot, it is understood that the grant funding for any rebates and adders would be provided by the RI OER from funding available for this purpose.

Implementation Schedule. A schedule for the SRP Solar Pilot is provided at the conclusion of this report, in which 80% of the resource portfolio becomes operational for distribution support in approximately 12 months, before the summer of 2015. Success in meeting this schedule will depend on the response of the markets to the SRP procurements, and also the avoidance of delays in the development process.

Footnotes: Executive Summary

- ES-1: 2014 System Reliability Procurement Report, The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453
- ES-2: Solar PV generation corresponds well with the peak periods for the wholesale power markets and the transmission system. In fact, all the PV configurations studied for Tiverton generate at least 66% of their annual output during peak periods. However, to provide distribution system capacity, PV output is needed during just one or a few peak summer hours.
- ES-3: The analysis of hourly PV production for the SRP Pilot area was conducted by Clean Power Research with the SolarAnywhere® Data system. http://www.cleanpower.com/products/solaranywhere/sa-data/
- ES-4: For tracking configurations, output and DCP are high but there may be increases in capital and operating costs in order to achieve the incremental Distribution Contribution. These incremental costs are not reflected in the analysis of fixed arrays.
- ES-5: The 50% DCP used for the solar fields in the portfolio summary is approximately the DCP of the PV orientation (230 degrees) with the greatest Net Distribution Benefit in Figure 13 on page 13. 50% is also the expected value DCP based on an equal probability of development for each fixed orientation from 200 degrees through 260 degrees and for single-axis and dual-axis tracking.
- ES-6: "Solarize" is a term for local campaigns that increase penetration and drive down installation prices. For a description of the approach in Massachusetts, see http://www.masscec.com/solarizemass The 45% DCP used for the solarize PV in the portfolio summary is approximately the DCP of the PV orientation (220 degrees) with the greatest Net Distribution Benefit illustrated in Figure 16 on page 18, and 45% is also the expected value DCP based on an equal probability of development for each fixed orientation from 200 degrees through 240 degrees.

SECTION 1: SOLAR DISTRIBUTION CONTRIBUTION

1.1 Load Data for SRP Pilot Area

The starting point for this study is the need for sustained, reliable load relief that will allow for a distribution investment deferral. National Grid provided data on the hourly load on the relevant portion of the distribution system ("feeder 4") for each hour of the 3-year period 2011 through 2013.[1-1]

Without significant solar distributed generation (DG), the peak load in the Pilot area reached 9,800 kVa in 2011, as shown in Figure 2. While the peak load was lower in 2012, it reached nearly the same peak again in 2013.

The summer months were the focus of this analysis: June, July, August and September. For each of the three years, we selected the highest 10 percent, or 288, of the hours out of the summer peak period to analyze the potential contribution of solar PV. This use of 10% is analogous to its use in "90/10" load forecasts. Figure 2 shows how these hours constitute the top of each year's load duration curve.

The location of feeder 4 is shown on the map on the next page, extending from Tiverton into Little Compton. This defines the Pilot area for this study.

Figure 2: Feeder 4 Load for Top 10% of Summer Hours

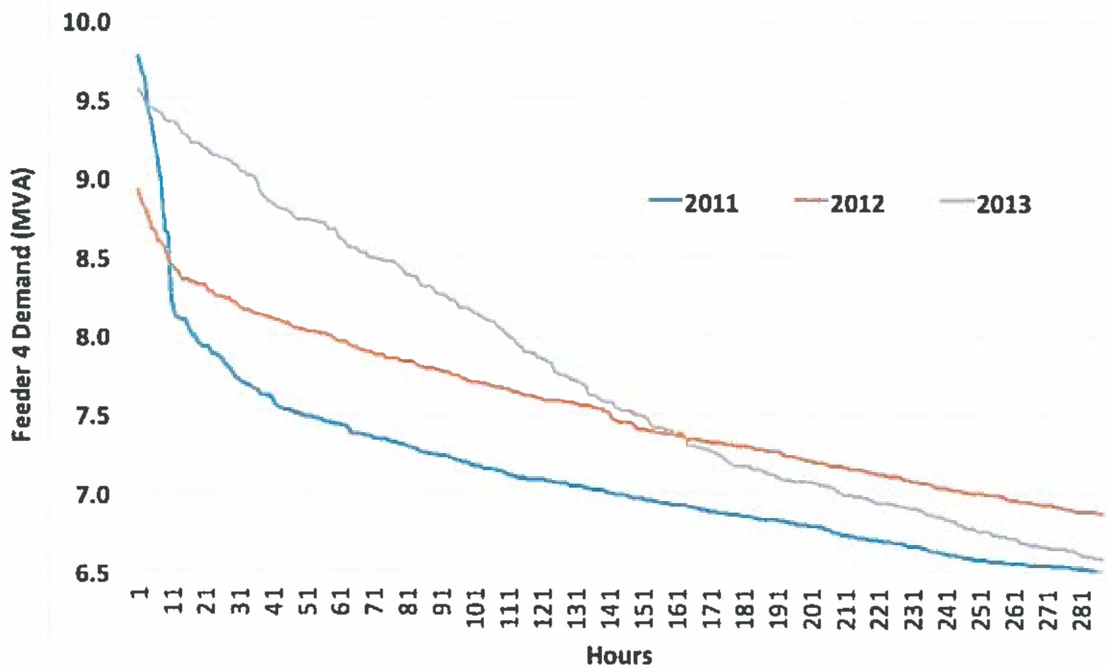
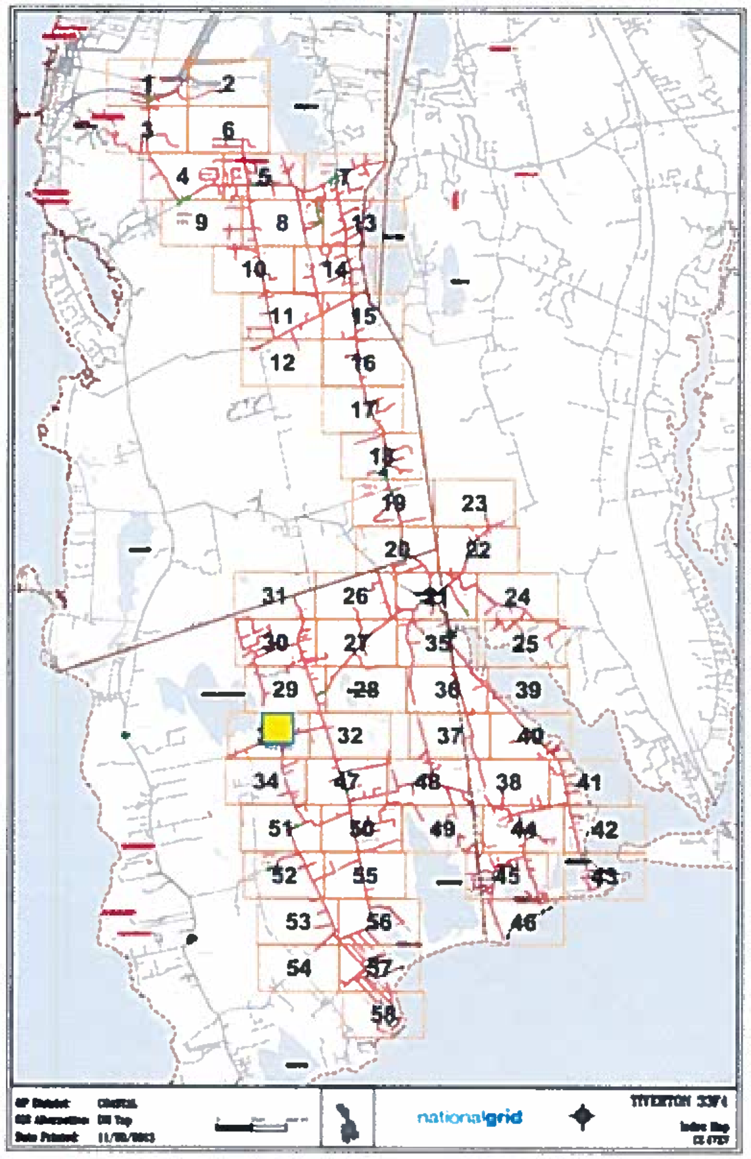


Figure 3: Feeder 4

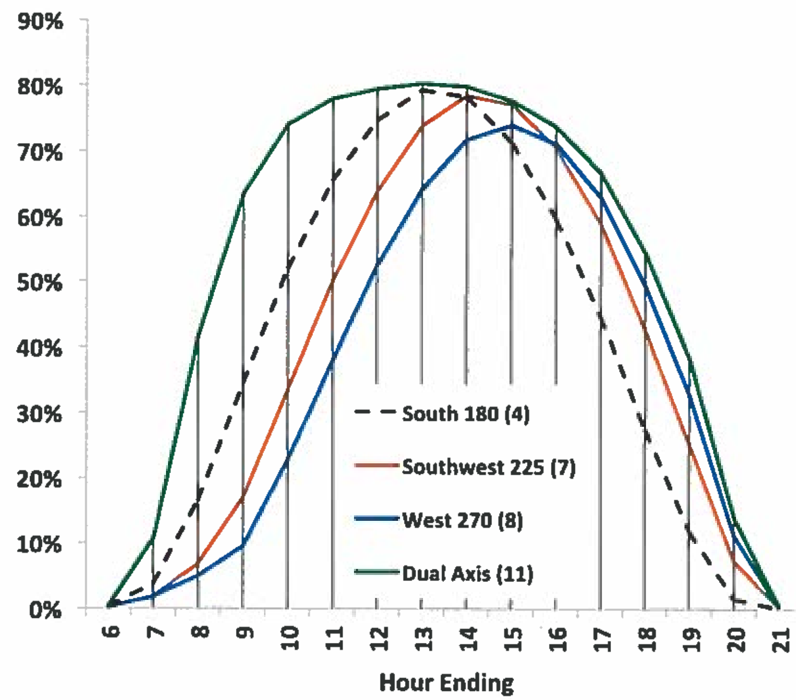


1.2 Historical Hourly Solar Generation in the Pilot Area

This study is based on the output that solar PV would have provided in the particular location of feeder 4 under the historical conditions in each hour of 2011 through 2013. The hourly PV production data was prepared by Clean Power Research for the SRP Pilot area with the SolarAnywhere® system.[1-2]

These PV data make it possible to compare the load relief that would have been provided to feeder 4 by different PV configurations. Figure 4 shows the increase in output in the critical late hours of the day from southwest and west-facing fixed arrays and from dual-axis trackers, compared with traditional south-facing fixed arrays.

Figure 4: Output of Solar Configurations on July 22, 2011



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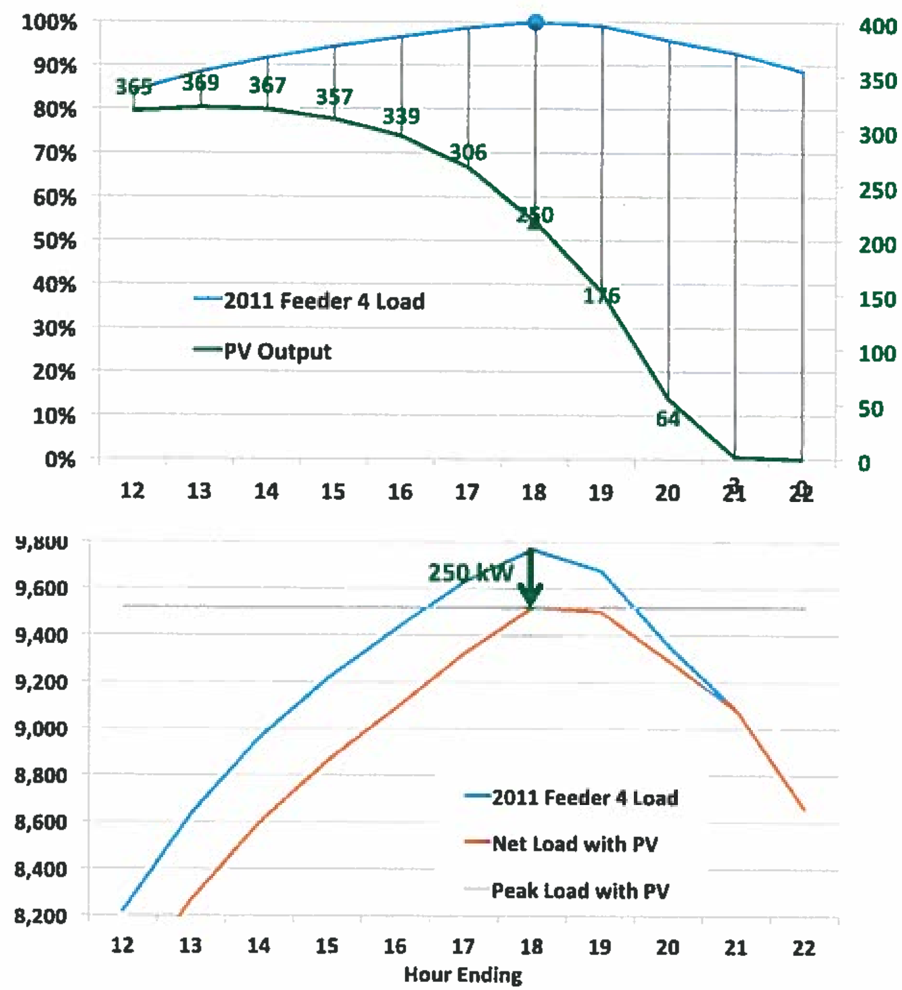
1.3 Distribution Contribution Methodology

The Distribution Contribution of solar DG is its ability to provide reliable load relief, which depends on its output in the hours with the highest loads. The highest peak load on feeder 4 in the three year study period occurred on July 22, 2011 in the hour ending 18 (from 5:00 pm to 6:00 pm). The hourly generation levels of five different PV configurations are shown for that day in Figure 5 on the previous page.

Figure 6 to the right zooms into 11 hours during that day.[1-3] The comparison of the two lines in the top chart highlights the rapidly falling PV output at the time the load is reaching its peak, but also shows that just over half of the PV capacity remains available to provide load relief in that hour. Specifically, the blue lines in Figure 6 show the actual load without any new PV, in percentage terms in the top chart and in absolute terms in the lower chart. The green line represents the output from one of the PV configurations: a dual-axis tracking system. Its output is plotted on the left axis as a percentage of the annual PV maximum output.

The basic approach of the Distribution Contribution Methodology is to identify the percentage of the PV's maximum output that would have been generated under historical peak conditions, and to size the PV resource to meet the need, which is to ensure that net loads will not be greater than the original maximum demand less the desired load relief (250 kW). In other words, the load must be kept at or below the horizontal line in Figure 6.[1-4] The orange line in Figure 6 is the result of this distribution contribution.

Figure 6: PV required on July 22, 2011 peak day to provide 250 kW load relief



The distribution contribution methodology summarized above is based on meeting a specified need, and the resulting DCP values are referred to as DCP-N (for Need). DCP-N values were calculated for each year and configuration [1-5] and are presented in the solid lines in Figure 7, and on the left side of Figure 8 below.[1-6] These DCP values are used in this report to develop a resource portfolio for the Pilot (Figure 1, page 3), and to estimate the economic value of the distribution contribution from PV resources (Section 2.4). For these purposes, an average DCP-N is computed for the two years with the lowest values, as shown in Figure 8; this metric is used in the rest of this report unless noted otherwise.

Since the DCP-N calculation hinges on relatively few hourly data points – albeit the ones that matter most – we have calculated an alternative version of the DCP which gives some consideration to the solar output in all of the top 288 hours for each summer. These values, called DCP-L (for Load-weighted), are shown on the right side of Figure 8 below. While they vary less between the PV configurations, they generally fall into the middle of the range of DCL-N values, as illustrated in Figure 7 to the right.

Figure 7: Distribution Contribution Percentages (DCP)

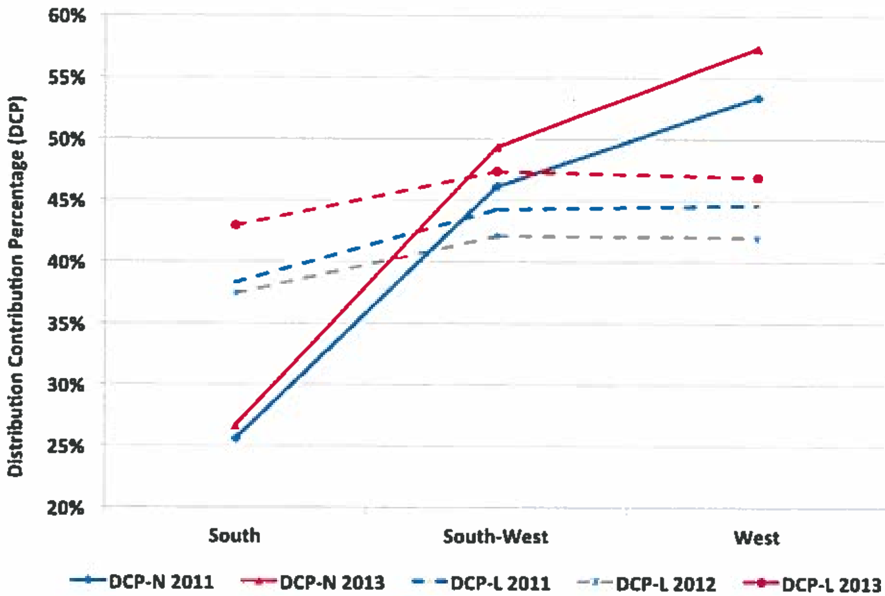


Figure 8: Distribution Contribution Percentages (DCP) for Selected PV Configurations

	DCP-N (Need)				DCP-L (Load-weighted)			
	2011	2012	2013	Average of 2 Lowest Years	2011	2012	2013	Average of 2 Lowest Years
4 South 180	25.6%	67.3%	26.7%	26.1%	38.3%	37.4%	42.9%	37.9%
7 SW 225	46.1%	79.5%	49.3%	47.7%	44.2%	42.1%	47.3%	43.2%
8 West 270	53.4%	69.9%	57.4%	55.4%	44.6%	42.0%	46.9%	43.3%
9 1-Axis	55.7%	72.0%	60.0%	57.9%	49.0%	46.1%	53.5%	47.6%
11 2-Axis	58.9%	83.4%	63.5%	61.2%	50.3%	47.4%	55.1%	48.9%

1.4 PV Energy and Capacity Values

The fixed PV array configurations that are oriented to the west of south generate less electricity, as shown in the bar chart in Figure 9. However, they provide a greater distribution contribution and more generation capacity, as shown in the table in Figure 10 below. Tracking configurations provide high values for both generation and T&D.

Figure 10 shows the energy and capacity characteristics that depend on PV output as it varies in each hour; these values are based on all three years 2011 through 2013.[1-7] These are in the same format as the corresponding inputs to the screening model for the Rhode Island Cost Test used to evaluate energy efficiency measures.

Peak energy is based on an average of PV output values for weekday hour ending 8 through hour ending 23. Coincidence for capacity is calculated as the median of PV output for weekday hour ending 14 through hour ending 18 for the summer months or, for winter, hour ending 18 through hour ending 19.[1-8]

Figure 9: Annual Output of Key PV configurations

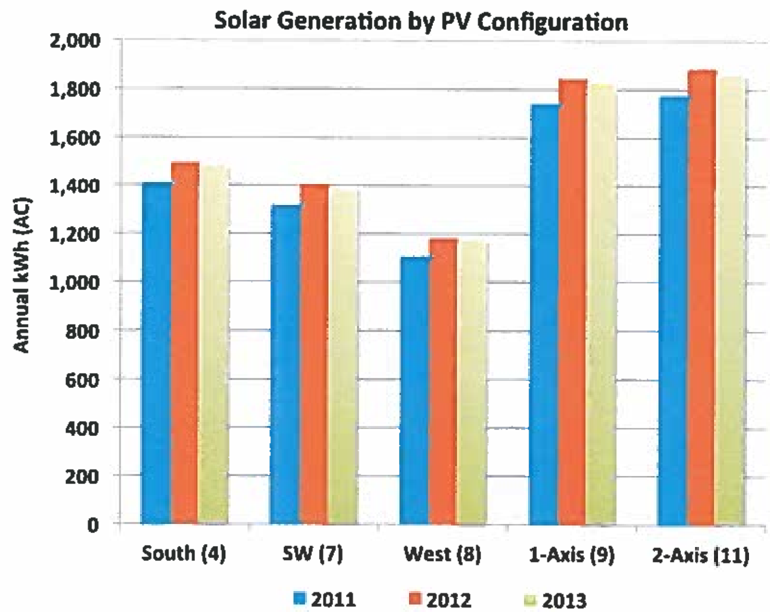


Figure 10: Energy and Capacity Parameters for PV in Pilot Area

	Energy Savings					Capacity Savings				
	Gross Annual kWh	Winter Peak Energy %	Winter Off-Peak Energy %	Summer Peak Energy %	Summer Off Peak Energy %	Summer Coincident (%)	Winter Coincident (%)	Annual Median (%)	Trans. Coincident (%)	Distribution Coincident DCP-N (%)
1 Flat	1,240	36.5%	18.9%	30.7%	13.9%	40.2%	2.3%	24.3%	37.3%	34.4%
4 South 180	1,463	40.2%	20.8%	27.0%	12.1%	42.6%	3.0%	24.4%	34.4%	26.1%
7 SW 225	1,371	39.4%	20.1%	27.9%	12.5%	51.4%	4.4%	33.7%	49.6%	47.7%
8 West 270	1,154	37.0%	18.8%	30.4%	13.8%	54.3%	4.7%	34.7%	54.8%	55.4%
9 1-Axis	1,805	39.6%	21.0%	27.0%	12.5%	57.6%	4.9%	36.6%	57.7%	57.9%
11 2-Axis	1,841	39.5%	20.9%	27.0%	12.6%	59.0%	5.0%	38.4%	60.1%	61.2%

Footnotes: Section 1

- 1-1: Feeder 4 was directly metered for most of the hours in these three years. For some hours, to adjust for anomalies, metered loads for two transformers were combined and allocated to feeder 4. The revised data is in an excel file named "2014-1-23_cps_Revised_Calcs_Tiverton 33F3 33F4_MW-MVAr_rc".
- 1-2: The SolarAnywhere® Data system utilized by Clean Power Research is described at: http://www.cleanpower.com/products/solaranywhere/sa-data/ The PV configurations were defined by Mark Farber for this SRP Solar Pilot project. These data are in the file "master-file_PV-output.xlsx"
- 1-3: The 11 hours in Figure 6, all on July 22, constitute the top 11 hours of the load duration curve for the summer of 2011.
- 1-4: The new maximum hourly demand with the PV contribution must be 250 kW (in this case) lower than the original maximum demand. The original maximum demand and the reduced maximum demand may or may not occur in the same hour, especially when the original loads in hours adjacent to the peak are not much different from the peak load itself. For this reason, the calculation of DCP-N values is set up with iterative adjustments of the needed PV, with a "solver" in the spreadsheet.
- 1-5: The calculations are performed for the top 288 hours of each summer in the excel file named "Sum_Load_PV_Size_DCP", which looks up load data and PV output values from two other files.
- 1-6: These DCP figures in Figures 7 and 8 take into account the reduction in local line losses that is estimated to result from each PV configuration in each summer hour. This methodology is presented in the "losses" sheet of the file "Sum_Load_PV_Size_DCP." The fixed-array configurations compared in these Figures were all assumed to be at a tilt of 30 degrees. Data on other tilt angles and configurations are included in the file "master-file_PV-output.xlsx"
- 1-7: In Figure 10, transmission coincidence is assumed to be an average of the coincidence figures for summer generation and distribution.
- 1-8: Various market rules and regulations govern eligibility for a solar generator or other participant to actually receive value for these energy or capacity attributes; see Section 2, footnote 2-2.

SECTION 2: DEVELOPING GRID SUPPORT SOLAR FIELD(S)

2.1 Characteristics of Solar Fields for SRP Pilot

The largest component of the portfolio of solar resources described in the Introduction (Figure 1) is the Grid Support Solar Field (or fields), with a target of 280 kW. This resource is targeted to meet a majority (approximately 57% or 140 kW) of the distribution need, as shown in the resource portfolio in Figure 1 (page 3).

The actual kW size of the project(s) will depend on which solar configurations are bid or installed by potential developer(s), and their Distribution Contribution Percentages (DCP). The most attractive configurations are discussed in Section 2.4 below.

This portion of the solar resource portfolio is anticipated to be ground-mounted because the installation(s) can be designed and monitored to focus on the distribution support objective.[2-1] This PV generation field could be interconnected behind a customer meter or directly to feeder 4.[2-2]

A single facility or a small number of relatively larger facilities will be more cost-efficient than multiple smaller solar projects, as well as being more convenient to monitor.

One or more solar PV vendors could develop and finance these ground-mounted projects, or National Grid could seek approval to construct and own such PV facilitie(s). The following sections review potential ownership and procurement options.

How much land may be required?

250 kW to 300 kW of solar fields would likely require approximately 2 to 3 acres for the solar arrays and all other land enclosed by the site boundary, based on an NREL study of the size of actual projects.* Single-axis tracking requires slightly less land since it requires less capacity to provide the same distribution contribution, even though it uses more land for the same kW capacity compared to fixed ground-mounted arrays. A 2-axis tracking system would require more land, which could vary significantly according to the design and manufacturer of the equipment. The accompanying table compares the acres needed for key configurations to provide a distribution contribution of 140 kW, based on the DCP metric and the NREL data on actual project sizes.[2-3]

Figure 11: Land Requirements for Solar Field(s)

	Total Acres/MWac	DCP	Capacity to contribute 140 kW to need	Total Acres Needed
Fixed SW	7.6	48%	292	2.2
1-axis	8.7	58%	242	2.1
2-axis	13.0	61%	229	3.0

* Land-Use Requirements for Solar Power Plants in the United States, Ong et. al., June 2013, NREL/TP-6A20-56290

2.2 Ownership Options for Grid Support Solar Field

National Grid Ownership Option. If National Grid is to construct and own or lease a 250 kW to 300 kW PV facility, it could follow procedures that it has used in other states to procure and install PV systems. The company owns property adjacent to its substation which could potentially be used for this grid support solar field, although various development and interconnection issues would need to be addressed. Subject to resolution of these issues, this property could possibly be made available for lease to a PV developer, which would help accelerate development.

National Grid could pay a turnkey price for the total installed cost of the PV facility, or could enter into a commercial lease for the equipment, and would follow appropriate regulatory procedures for recovery and accounting for capital and operating costs and the value of the facility's capacity and energy generation. The RI OER would determine the extent to which its budget for the SRP Solar Pilot would be used to cover any of the PV net costs under this approach.

Non-Utility Ownership Option. An alternative would be for one or more PV vendors to develop one or more Grid Support Solar Field(s), in which case each owner would presumably seek a DG Standard Contract, or its successor program, in the first Open Enrollment opportunity, and would seek any other financial assistance or incentives that would apply to any similar solar project at the time.

A PV developer or owner would incur incremental costs to configure the PV arrays to optimize Distribution Contribution, potentially including increased capital or other costs (e.g., for tracking systems) or a reduction in revenues (e.g., for orientation to the southwest or west). The SRP Solar Pilot budget would be used by RI OER to compensate the PV owner for these costs, and potentially to provide an additional positive incentive to encourage participation in this Pilot.

2.3 Procurement Options for Solar Field Developer

There are two options for a competitive procurement process:

1.) Selection of a PV developer through the procurement process for the solarize solar vendor. The solarize campaign is addressed below.

2.) RFP to select a PV developer with the best qualifications to optimize Distribution Contribution and/or the best bid for the incremental incentive required to optimize Distribution Contribution.

1.) Selection of a PV developer through the procurement process for the solarize solar vendor. A primary selection criterion in this approach would be the vendor's ability not only to sell and install the rooftop systems but also to develop and construct the Grid Support Project. It is not clear whether a single contractor that is currently active in the Rhode Island market has experience in all of these areas, but a team might be assembled to do both. This might also complicate the solarize development process.

2.) RFP to seek bids for the incremental costs required to optimize Distribution Contribution. In this option, an RFP would be issued by the state and/or by National Grid to select a PV developer to receive a grant for incentives specific to the SRP Solar Pilot. The evaluation of bids would be based in part on a metric of the pre-calculated $/kW distribution deferral benefit for each solar configuration minus the $/kW incremental cost bid by the PV developer. Each proposal would consist of the $/kW cost bid, the solar configuration selected, the kW capacity and the total grant requested. Each bid would also document the qualifications of the PV developer, and selection could be based in part on experience installing trackers and/or working with distribution-related applications.

2.4 Incremental Incentives to Optimize Distribution Contribution

The distribution contribution increases as azimuth orientation moves toward the west, although with diminishing returns after a certain point. The avoided distribution cost is shown in Column C in the table below (Figure 13. The incremental distribution value, compared with a south orientation, is shown in column D and in the green line in Figure 12. [2-4], [2-5]

As the orientation of a fixed array moves toward the west, electricity generation falls off, as shown in Figures 9 and 10 on page 9, so a PV developer loses revenue, if it is based on the quantity of kWh sold. A grant could be provided that would represent the present value of this loss, so the PV owner would be indifferent to PV orientation and willing to improve the contribution to distribution.

Figure 12: Incremental Costs and Benefits – Fixed Arrays

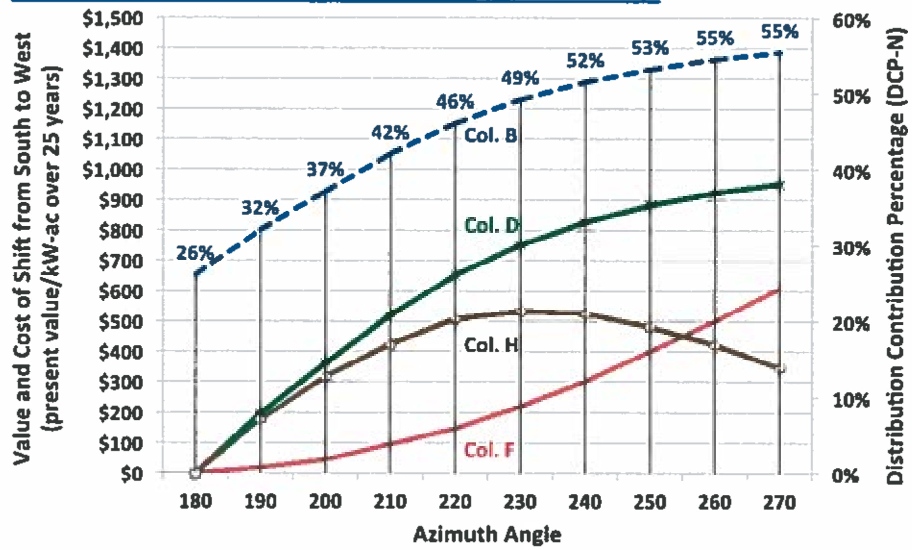


Figure 13: Incremental Costs and Benefits per kW-ac

A	B	C	D	E	F	G	H	I	J
Azimuth Orientation	Distribution Contribution (DCP-N)	Avoided Distribution $/kW	Incremental Distribution Value	Reduced Generation (kWh/year)	Incremental Cost/Bid to Optimize DC	Cost as % of Value (Col. F/D)	Net Distribution Benefit/kW	Capacity to contribute 140 kW to need	Total Incremental Cost/Bid
180	26%	$ 840	$ -	0	$0	0%	$ -	544	$0
190	32%	$ 1,035	$ 195	9	$18	9%	$ 177	444	$7,988
200	37%	$ 1,200	$ 360	23	$45	13%	$ 315	383	$17,224
210	42%	$ 1,359	$ 519	48	$95	18%	$ 424	338	$32,119
220	46%	$ 1,492	$ 652	74	$145	22%	$ 507	308	$44,664
230	49%	$ 1,592	$ 752	112	$220	29%	$ 532	289	$63,496
240	52%	$ 1,666	$ 826	153	$300	36%	$ 526	276	$82,718
250	53%	$ 1,721	$ 881	204	$400	45%	$ 481	267	$106,767
260	55%	$ 1,763	$ 923	254	$500	54%	$ 423	261	$130,275
270	55%	$ 1,793	$ 953	309	$607	64%	$ 346	256	$155,608
1-axis	58%	$ 1,870	$ 1,030					245	
2-axis	61%	$ 1,980	$ 1,140					232	

The amount of such a grant could be based on developer bids. The red line, based on column F of Figure 13, represents an estimate of this incentive or cost on a per-kW basis that the pilot would incur to encourage an increase in distribution contribution, based on lost revenue.[2-6] The final column (J) in Figure 13 indicates the possible dollar amount of this cost for each PV orientation, based on the size of solar installation that would be required to meet the need.

The space between these red and green lines represents the net distribution benefit, which is also graphed in the brown line and shown in Column H of the table. This net benefit is greatest ($532/kW) at an orientation of 230 degrees (approximately southwest), where the DCP is 49%. This maximum net benefit could be obtained at an incremental cost or incentive of approximately $220/kW-ac. (The net benefit does not differ significantly between the orientations of 230 and 240 degrees.)

The net benefit is still substantial (approximately $423/kW) at 260 degrees, but diminishing returns have set in; this orientation provides a higher distribution benefit, with a DCP of 55%, but at a higher cost.

Figure 14: Potential Bids to Optimize Distribution Contribution

A Configuration / Azimuth	B DCP	C Distribution Value	D Bid Example ($/kW)	E Unit Score (C - D)	F kW (140 / B)	G Award (D x F)
2-axis	**61.2%**	**$ 1,140**	**$ 360**	**$ 780**	**232**	**$ 83,551**
1-axis	57.9%	$ 1,030	$ 330	$ 700	245	$ 80,997
2-axis	61.2%	$ 1,140	$ 450	$ 690	232	$ 104,439
240	51.5%	$ 826	$ 325	$ 501	276	$ 89,612
1-axis	57.9%	$ 1,030	$ 550	$ 480	245	$ 134,996
220	46.1%	$ 652	$ 200	$ 452	308	$ 61,605
240	51.5%	$ 826	$ 400	$ 426	276	$ 110,291
260	54.5%	$ 923	$ 500	$ 423	261	$ 130,275
200	37.1%	$ 360	$ 100	$ 260	383	$ 38,275

2.5 Competitive Bidding for Incremental Grant(s)

If a competitive bidding process is used to award a grant for the incremental incentive for the Grid Support Solar Field(s), the goal would not be to select the lowest grant bid, but could be to find the highest net benefit, as indicated above.

The table on this page (Figure 14) illustrates one way in which such a selection criteria could be established and applied in the bidding process. As stated above, under procurement option 2, the evaluation of bids to the Solar Field Developer would be based in part on a metric of:

- the pre-calculated incremental $/kW distribution deferral benefit for each solar configuration, illustrated in:
  - the green line in the chart and Column D in the table in Figures 12 and 13 above, and
  - Column C in the table on this page (Figure 14);

minus:

- the $/kW incremental cost which might be bid by PV developers, which is illustrated by:
  - the lower/red line in the Figure 12 chart and Column F in Figure 13, which are based on estimates of what a PV developer would need to stay whole financially as a result of reduced generation, and
  - Column D in the table on this page, which is a set of hypothetical bids to illustrate a potential scoring mechanism; bids may differ from the costs estimated in the previous table for various reasons, which could include the proposer's internal assessment of additional incentive needed to assign resources to developing a project of this relatively small size in this location.

In other words, each bid would be given a score calculated as column C minus column D of Figure 14, indicative of a net distribution benefit. In this example, a hypothetical bid of $360/kW is submitted by a developer proposing a dual-axis tracking configuration, which has a winning score of $780/kW.

Column G (on the right of Figure 14) illustrates an award that could be made (approximately $83,000), based on 232 kW of PV -- the quantity of PV that is necessary with its DCP of 61% to achieve the 140 kW of deferral designated in the potential resource portfolio (in Figure 1 on page 2). The calculation is the 142 kW need divided by the 61.2% DCP = 232 kW PV size needed.

The procurement could also allow larger PV sizes to be bid. Alternatively, the above score could be adjusted by weighing the distribution value more heavily than the bid amount, within an appropriate range.

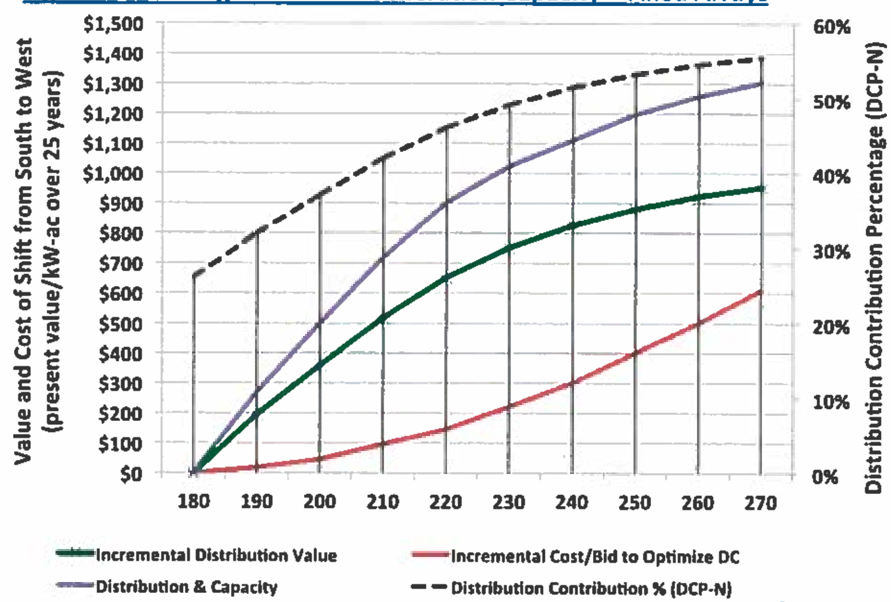
Bids could be submitted at levels higher (or lower) than estimated here as a result of differing developer assessments of risk and cost tradeoffs. For example, the incremental cost represented by the red line in Figure 12 (and replicated in Figure 15 here) is based on 25 years of reduced PV generation at a discount rate of 11.5%, which might be an appropriate discount rate for a solar developer or owner of commercial scale PV projects. However, lower discount rates for the lost revenue could lead to a higher incremental cost to improve the distribution contribution.

One procurement option to address the potential of high bids would be to set a cap on awards, most likely on a per-kW basis. A cap could be set at the level of the incremental distribution benefit shown in the green line in Figure 12 (replicated in Figure 15 here). However, there are also other benefits that might warrant paying higher incentives, either to deal with high bids or in order to obtain higher distribution contributions.[2-7]

For example, if the value of the incremental generation capacity (based on capacity values from Figure 10) is added to the distribution value, as diagrammed with the purple line in Figure 15, that combined value would warrant procuring the output of system(s) with higher DCPs to increase the contribution of solar PV to distribution, since the total benefit could be measured at a higher level. In order to realize this capacity benefit with current ISO-NE Forward Capacity Market rules, however, it might be necessary for the PV to be connected behind the meter of a retail customer where the generation is coincident with on-site load.

For a fixed array with an orientation of 230 degrees, the combined distribution and capacity value is approximately $1,000/kW. For a due west orientation, this value would be about $1,300. These values (plus any other incremental benefits that may be included) provide an upper level of incentives that would be paid in a procurement.

Figure 15: Adding Benefits of Generation Capacity – Fixed Arrays



Footnotes: Section 2

- 2-1: Ground-mounted systems could be fixed arrays or trackers. One benefit of a solar field is the potential for the use of solar tracking systems. The solar tracking configurations have high DCP distribution contribution percentages, but they do not incur the reductions in annual generation that come with orienting fixed PV systems to the southwest or the west. In fact, tracking systems generate approximately 25% more electricity over the year than fixed systems. While there is not enough regional experience to make reliable estimates of capital or operating costs, trackers may have somewhat better economics than fixed systems. In view of the cost uncertainties, it is not clear what bids developers will submit for trackers in a competitive procurement; this is one reason to hold a competitive procurement for incremental grant(s).
- 2-2: Under current market rules, subject to interpretation and changes, a solar generator, or an electric distribution company which has purchased solar generation, may not be eligible to participate in the ISO-NE capacity market. However, capacity costs may be reduced if the solar is connected behind a customer meter and reduces the measured peak demand.
- 2-3: The NREL data in Figure 11 is only used for comparative purposes; the kind of PV projects planned for the Pilot area may have different requirements. Based on visual inspection of portions of the Pilot area, including along Route 81, and on review of on-line real estate offerings, it appears that (a) some parcels may currently be for sale with sufficient acreage, and (b) significant land resources may be available for solar generation uses.
- 2-4: The analyses in Section 2.4 are performed in the sheet "Incremental" in the file "SRP-PV-Screening-Model-Structure". The values in Figures 12 and 13 for each 10 degrees of azimuth orientation for fixed arrays are estimated on curves based on the values for orientations of 180, 225 and 270 degrees. For trackers, see footnote 2-1.
- 2-5: The Avoided Distribution Cost and the Incremental Distribution Value in Figure 12, Columns C and D are based on the incremental Distribution Contribution Percentages times the present value of the deferral savings and avoided distribution cost. The deferral savings are computed by National Grid in the 2014 System Reliability Procurement Report (page 20), as the present value achieved in each year through 2017 by avoiding the wires solution for another year. For the remaining years of the life of the solar installation, the benefit is based on the annual avoided distribution cost of $152 per kW that is used for statewide analysis of energy efficiency measures. The $152/kW figure was developed by National Grid, before the inflation and discounting that is done for the energy efficiency cost analysis. After the 2017 end of the SRP deferral period, the local SRP distribution investment is assumed to be made. Other distribution costs may still be avoided between 2018 and 2038 by reducing load growth; these are assumed to be 25% of the statewide avoided cost for the next 5 years, and then 50% for 5 years, and then 100% through 2038.
- 2-6: The Incremental Cost/Bid to Optimize DC in Figure 13, Column F is based on lost potential revenue from reduced PV generation. This simple methodology is presented in the sheet "lost revenue" in the file "SRP-PV-Screening-Model-Structure". An example is discussed in the Executive Summary (see page 2) of the $145/kW present value cost for an orientation of 220 degrees due to a reduction of 74 kWh/year. This reduction is valued at 25 cents/kWh every year for 25 years (with a degradation of PV output of 0.5%/year), assuming these annual values would then be discounted at 11.5% (such as by a solar developer or owner of commercial scale PV projects). Lower discount rates for 25 years of lost generation would indicate a higher incremental cost to improve the distribution contribution. This assumption of 25 cents/kWh is a straight-line extrapolation to the 280 kW size of a Grid Support Solar Field in the portfolio summarized in Figure 1, based on the prices bid into the third 2013 RI DG Enrollment for the nearest PV project sizes, specifically (a) a price of approximately 19 cents/kWh for a PV project sized at 500 kW and (b) a price of 28 cents/kWh for a 150 kW PV project. Source: http://www.nationalgridus.com/non_html/4277-4288-3rd%202013%20DG%20Enroll%20%28PUC%201-6-14%29.pdf
- 2-7: Some of these benefits have not been quantified for this report. Examples include transmission benefits, the option value of demand reductions, or the potential to reduce the length of time that demand response is asked of participating customers on the feeder.

SECTION 3: SOLARIZE CAMPAIGN FOR ROOFTOP INSTALLATIONS

3.1 Solarize Campaign

An important component of the solar resource portfolio for this pilot is a set of rooftop installations on homes, small businesses and public buildings that take load from feeder 4. Rhode Island OER and National Grid could work with government officials and community groups in Tiverton and Little Compton to initiate a "solarize" campaign based in part of the solarize model in Massachusetts and elsewhere.

A unique element in this case will be the targeting of rooftops facing to the west of south, in order to improve the distribution contribution. To achieve this goal, incremental incentives can be offered that increase with the azimuth orientation, as described below.

Residential and other small rooftop solar installations are not as cost-effective as most configurations for a larger solar field. Also, a solarize program and marketing campaign takes months to organize and implement.

Nevertheless, the solarize portion of the solar portfolio has several important advantages. Each small PV project can be installed much faster than larger and more complex projects, and project costs are better known. These multiple locations may diversify the potential impact of passing clouds on partly-sunny days.

These rooftop systems will provide valuable data for future initiatives to use new or existing solar PV for distribution planning. In particular, this SRP pilot is a good opportunity to test the effectiveness of outreach targeted to roofs oriented to the west of south.

The solarize-style campaign could be implemented over a two year period to take into account the limited residential PV market to date in the area. The campaign would launch in 2014 to test the interest and ability of the local community to mobilize a campaign and to achieve some early residential installations. During 2015, changes could be made to increase installations before summer of 2016.

3.2 Penetration Rates

According to National Grid, there are 2,450 residential customers on feeder 4. Of these, 51% are located in Tiverton, and the other half in Little Compton. There are also 188 nonresidential customers.

One source of relevant experience to inform predictions of penetration in the SRP Pilot area is that of the early solarize communities in Massachusetts. The number of contracts signed in 2012 was approximately 0.74% of the households in a set of ten communities analyzed for this study.[3-1] For the four smallest communities, which had an average of 3,010 households (Mendon, Shirley, Lincoln, and Montague), the penetration rate of PV contracts was higher, at 0.91%, for an average of 27 contracts per community.

For a longer period of two to three years through May of 2014, the total number of contracts signed reached approximately 1.14% of the households in the same 10 communities.[3-2] For the four smallest communities, the penetration rate reached 1.38%, for an average of 41 contracts per community.

Based on this experience, it is reasonable to expect that a successful outreach campaign could attract 1.25% residential penetration, for approximately 31 PV participants in the pilot area over two years. If the average system is 5 kW in size, that would represent 155 kW of residential PV capacity. If penetration of 1.5% could be achieved for nonresidential customers, that would be 3 PV installations, which should average at least 25 kW, for another 75 kW of capacity. This would be a total of 230 kW of PV capacity.

3.3 Incentives for Degrees of Orientation to West

The solarize component of the SRP Solar Pilot should be designed to achieve a significant distribution contribution by encouraging the enrollment of homes and small businesses with roofs that face to the west of south.

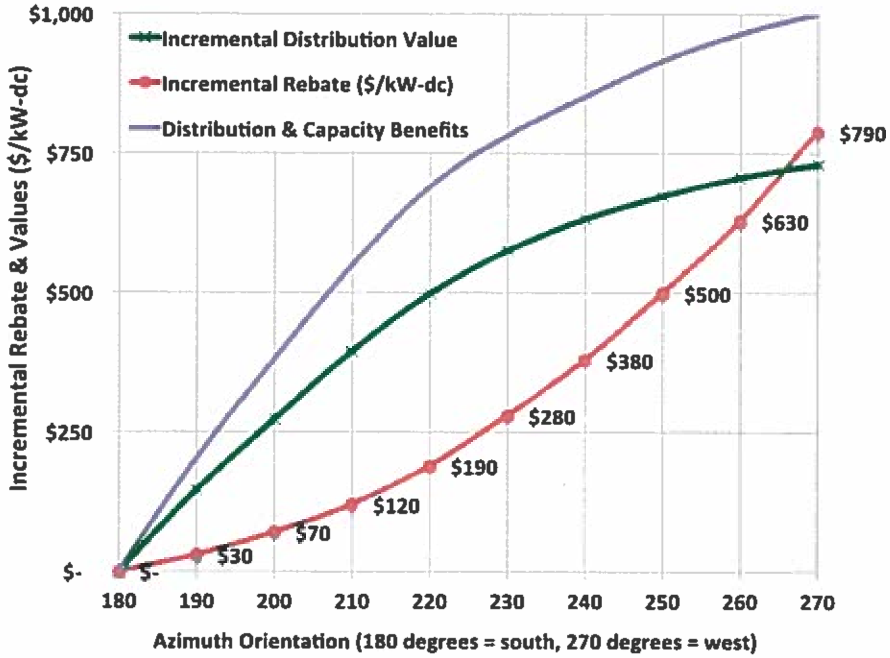
To do this, incremental rebates could be offered that would approximate the present value to homeowners of the reduction in the future savings in their electric bills (including though net metering). The levels of these incremental rebates are estimated in the red, bottom line in Figure 16 for residential customers. This chart is in units of $/kW-dc (unlike Figures 12 and 13) to be comparable with existing incentives that are based on kw-dc. These rebates are based on the assumptions that electricity savings are valued at 17 cents/kWh in 2014, escalating at 2.5% and discounted at 4.6%/year.[3-3] These rebates should be fixed and offered in advance as a function of azimuth orientation.

These incremental rebates could be paid directly to each participating homeowner in the pilot area who installs PV that is oriented significantly to the west of south, perhaps as an "instant rebate". As part of the solarize campaign planning, it would be important to simplify the messaging and participation requirements so that added complexity does not reduce participation.

Once the orientation reaches 260 degrees azimuth, we estimate that homeowners would require $630/kW-dc to compensate them for these lost savings – a level which has nearly reached the value of the distribution deferral for that azimuth, which is shown in the green line.

If the value of the incremental generation capacity (described in Section 2.5 above) is added to the distribution value, as diagrammed with the purple line, that combined value would provide a rationale for offering rebates that are at the high end of

Figure 16: Incremental Costs and Benefits for Residential Fixed Arrays ($/kW-dc)



the range of distribution benefits, in order to increase the solar distribution contribution.[3-4]

The total payments of incremental incentives for the rooftop solarize projects can be estimated by assuming that there is an equal probability of installations from 200 degrees to 240 degrees.[3-5] This leads to an expected value of $208/kW-dc for the incremental rebate. Applied to 240 kW of rooftop projects, this is a total expenditure of only $50,000.

In addition to the above rebates to offset reduced PV output and increase DCP, it may also be desirable for this solar pilot to offer an additional bonus to motivate customers to "act now". Incentives are addressed further in Section 3.5 below.

3.4 Initial Community Planning for Solar Outreach

Massachusetts experience suggests that local support and a time-and-geography-bounded marketing program is key to residential market penetration. The backing of state and/or local parties substantially boosted market interest beyond the marketing pitch of the private installer. RI OER, or a non-developer independent consultant, could introduce the solar grid-support concept to the target communities, to prepare for subsequent outreach and procurement steps for both residential and other solar projects. The following issues need to be addressed at the local level:

- *Community awareness.* Hold one or more public meetings to alert the residential and business community of the coming program. Informally solicit any interest in potential sites for the ground-mounted facilitie(s).
- *Solar champion(s).* Explore, and preferably identify, individual(s) or small groups that can become solar champions during a limited-term solarize-style program. These champions have been one of the keys to market participation in MA programs.
- *Property tax.* Meet with town officials to urge them to clarify solar property tax policies for user-owned and for third-party-financed systems, residential and commercial. Towns are allowed by RI statute to extend a property tax exemption for solar, at the discretion of the town.[3-6] Property tax can be a determining factor in PPA rates, as much as $.10/kWh for high tax rates and full-commercial-value assessments.
- *Permitting, safety and zoning.* Assess the interest and capabilities of town electrical inspectors and fire departments. Provide networking, training, or backup engineering support, if needed. The goal is to get local officials up the learning curve, and to clarify procedures and rules, to speed up and lower the cost of installations without compromising quality or safety.

3.5 Outreach and Contracting

The goal of the community campaign will not be so much to boost competition as to buy down or drive down soft costs and to fast-track a local market. Steps will include:

- Undertake a competitive procurement to offer a temporary monopoly in the target area to a single solarize contractor. Pick a winner based on bid pricing (e.g., in volume tiers) as well as business experience and solarize marketing plan, so it's not just based on the lowest bidder.
- Engage a local solar champion(s) to facilitate community involvement. Solarize developers in MA have identified this as the most important ingredient of success.
- Offer a small grant to the local champion(s) to facilitate local support, accelerate the startup of the local campaign, and increase the overall penetration over one or two years.
- Coordinate solarize outreach with the marketing of SRP efficiency and demand response options in the pilot area. This integrated approach was tested and found to be successful in NSTAR's Marshfield Energy Challenge.
- Design and run the solarize campaign like the pilot that it will be. Cap the program term and volume at the outset so it doesn't become a runaway.

During the second year (after the beginning of the summer of 2015), changes could be considered in incentive levels, outreach strategies or PV contractor(s). PV installation prices may fall, and penetration patterns will begin to emerge. Customer incentives could be revised downward or upward based on experience to date.

3.6 Solarize Implementation Costs

Rebates to solarize customers were discussed in Section 3.3 to offset reduced PV output and increase DCP, and it was estimated that rebates for 240 kW of rooftop projects could total only $50,000 based on an equal probability of installations from 200 degrees to 240 degrees, which results in an expected value of $208/kW-dc for the average incremental rebate. An "act-now" bonus of 50% of the base rebate would increase the outlay to $75,000.

That calculation was based on an estimate of a residential discount rate; assuming a higher discount rate for the other portion (33%) of the solarize rooftop PV would reduce the rebate amount by almost 20% to about $60,000. This would be a suitable low estimate for the funding required for incremental rebates and bonuses.

As noted above, customer incentives could be revised downward or upward based on initial penetration levels. A higher estimate for rebate and bonus funding could be $125,000, based on the following alternative assumptions:

- a rebate that is 20% higher if needed to achieve penetration, or a penetration rate that is 20% higher than assumed here, and
- a change in the probabilities of adoption to 20% for orientations of 220 and 230 degrees and 30% for 240 and 250 degrees.

Funding will be required to engage the local solar champion(s) and/or to cover their out of pocket expenses, to develop and refine marketing messages and design and print collateral materials for the solar campaign, to plan and coordinate interactions between the selected solarize contractor and all the other entities involved in outreach and implementation, etc. These planning and marketing costs may reach $100,000 to $200,000. Together with the rebate and bonus outlays discussed above, this would bring the budget for solarize portion of the solar portfolio to a range of $175,000 to $325,000.

Footnotes: Section 3

- 3-1: 2012 Solarize Massachusetts Program Update:

  http://images.masscec.com.s3.amazonaws.com/uploads/attachments/Create%20Basic%20page/2012%20Solarize%20Massachusetts%20Program%20Update%20FINAL.pdf
- 3-2: RPS Solar Carve-Out Qualified Renewable Generation Units, Updated June 6, 2014, excel spreadsheet:

  http://www.mass.gov/eea/docs/doer/rps-aps/solar-carve-out-units.xlsx
- 3-3: The calculations of present value of lost revenue are done in the sheet "lost revenue" in the file "SRP-PV-Screening-Model-Structure".
- 3-4: There are also other benefits, as noted in Section 2.5 above, that might warrant further increasing the contribution of solar PV to distribution, which have not been quantified in this analysis, such as the potential to reduce the amount of time that demand response is asked of participating customers.
- 3-5: For additional information on the total rooftop capacity and DCP calculations, see footnote ES-7 on page 4.
- 3-6: For Rhode Island tax information, see:

  http://webserver.rilin.state.ri.us/Statutes/TITLE44/44-3/44-3-21.HTM

SECTION 4: SCHEDULE FOR SOLAR PILOT

4.1 Schedule

Before the peak loads of the summer of 2015, National Grid would welcome as much as possible of the load relief from solar that is contemplated in the resource portfolio in Figure 1. However, the resources in the portfolio will require significant time for marketing, development, design, contracting and installation. Therefore, the summer of 2016 is a more realistic time to expect full implementation.

The schedule in Figure 17 is designed to achieve solar installations as soon as possible by issuing the procurements described in this report by August and September of 2014.

- With this schedule, some of the solarize rooftop installations could be online before next summer, but another year will likely be required to achieve the resource portfolio targets – i.e., before the 2016 peak load.
- For the Solar Fields, it would be challenging for developers to be ready for the October 2014 DG contract enrollment unless systems were already in development. Even if that schedule is met, it is not certain that one or a few projects totaling 280 kW could be approved and constructed before the summer of 2015, so the spring of 2016 is a more likely time to complete these installation(s) as well.

Figure 17: Potential Schedule for SRP Solar Pilot

				Month	1	2	3	4	5	6	7	8	9	10	11	12
		Responsibility	Start	End	July	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Solarize Campaign:																
A	Community Solar Planning	State & Towns	July	December												
B	Solar Coach Outreach	State & Towns	August	Ongoing		Δ										
D	Solarize RFP Release, Selection	RI OER	September	November			Δ		Δ							
E	Contracting & Installation	Solarize Contractor	January	Ongoing												
Grid Support Solar Field(s):																
F	SRP PV RFP Release, Selection	RI OER/NG	August	September		Δ	Δ									
G	Preparation for DG Enrollment	PV Developers	October	October												
H	DG Contract Open Enrollment	National Grid	October	November				Δ	Δ							
I	PV Financing & Construction	PV Developers	December	June												Δ

PEREGRINE ENERGY GROUP

NECEC 1-3

Request:

Has the Company done any evaluation of the value of distributed generation (i.e., benefits) to the broader energy system? If so, please provide the data, assumptions and analysis results.

Response:

Please see the Company's response to NECEC 1-2.

NECEC 1-4

Request:

Has the Company assessed the relationship between overall monthly consumption (in kWh) and local (including circuit) and regional system peaks? Has the company analyzed the relationship based on net consumption, gross consumption or both? Please provide the data, assumptions and all analysis results.

Response:

The Company has not assessed the relationship between overall monthly consumption (in kWh) and local or regional peaks as part of the analyses performed for the purposes of proposing rates in this docket. It should be noted that the Company's allocated cost of service study allocates costs to customer classes based upon the class's peak demand which is intended to approximate customer impacts on individual feeders.

The Company routinely performs analyses on the loading conditions of various feeders and substations using the metered information available from meters installed at each substation. However, consumption data (kWh use) for customers on individual feeders cannot be obtained from billing system records; therefore, the Company's analysis of the relationship between maximum kW and maximum kWh was performed for individual customers using the available load research data.

NECEC 1-5

Request:

In response to CLF 1-5, the Company stated that they were "heavily involved in the Distributed Generation Working Group (DGWG) that developed New England-wide forecasts of PV." Did the Company provide capacity numbers to ISO-NE? And if so, what numbers did they provide? If those numbers were less than the annual capacity allowances in the REG program, why were they discounted?

Response:

The Company did not provide any numbers to ISO-NE. The Company provided ISO-NE with a listing of all DG facilities connected to its distribution system as part of the Distributed Generation Working Group (DGWG) process. As all projects 60 kWs or greater have a generator asset set up for them to reduce costs of the various DG programs in Rhode Island, ISO-NE analyzed the hourly generation data for these assets as well as other solar generating assets in other states to arrive at the factor it published in the DGWG report as discussed in the Company's response to PUC 2-1.

Prepared by or under the supervision of: Timothy R. Roughan

NECEC 1-6

Request:

Are distribution costs allocated by circuit to those customers on the circuit or allocated to customers by circuit type based on an average cost for that circuit type across the system?

Response:

The Company does not allocate costs of individual circuits to customers on that circuit in performing its allocated cost of service study. Please see the Company's response to Division 1-16 for a discussion of the issues related to designing rates based on geographic location.

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

NECEC 1-7

Request:

In response to PUC 1-16, the Company asserts that National Grid's peak occurs in September for all rate classes except G-62. However, in response to PUC 1-14 the Company indicated that the highest percentages of individual peaks were in January, July, and August for A-16 and C-06 customers. Please explain what is driving the September peak in those rate classes.

Response:

The table included in the Company's response to PUC 1-14 indicates the month during which each customer's maximum monthly use, measured in kWh for the entire billing period, occurred. As described in the Company's joint pre-filed direct testimony, a customer's maximum monthly use may be a reasonable indicator of the customer's maximum kW use—that is, the customer's peak demand. Customer maximum demands occur at various times during the day and month. Although the table in the Company's response to PUC 1-14 indicates when customer maximum demands may occur, it does not indicate when customer coincident demands occurred—that is, the maximum demand of all customers at the same point in time. Therefore, the table in the Company's response to PUC 1-14 reflects the diversity of demand present on the system.

The system peak, or the coincident peak, is measured as the highest aggregate load occurring on the system during a single hour. The Company's system peak during calendar year 2014 of approximately 1,640 MW occurred in September. However, this peak level was only slightly higher than the July 2014 peak of 1,620 MW, and significantly less than the 2013 peak of 1,970 MW that occurred in July 2013, and the 2012 peak of 1,890 MW occurring in July 2012. The 2014 summer peak was the lowest peak experienced in the Company's electric service territory since 2004. However, the actual day/hour that the system peak occurs in any particular year is relatively unimportant as any weekday of the year may become the peak day for the system or an individual feeder in response to weather and customer load conditions that change over time and the Company must plan to have capacity available at all times during the year.

In addition, the warmer than normal temperatures that led to the September 2014 peak occurred for a relatively short period of time. Cooling degree days (CDDs) [1] for the Company's electric service territory for the entire month of September 2014 were 163.0, as compare to CDDs for August 2014 of 215.1, and July 2014 of 213.5. Customers who typically use more electricity during warm weather months are more likely to experience their maximum monthly usage during either July or August, the two months during the year that have the highest number of

[1] A Cooling Degree Day is calculated as the day's actual average temperature minus 65 degrees. Cooling degree days relate the day's temperature to the expected energy demands for air conditioning.

CDDs. Average use per customer is also typically higher during the summer months as compared to the winter months; therefore, the Company's system peak (i.e., the coincident peak) occurs during the summer. However, although the Company system peak typically occurs during the summer months, it is likely that certain feeders may peak, or may become highly loaded, during the winter months. As evidenced by the table provided in the Company's response to PUC 1-14, January is the highest use month for 23.5% of residential customers.

The Company cannot predict which day or month the system peak, or individual feeder peaks, will occur each year. Customer load management activities such as installation of distributed generation or energy efficiency measures and introduction of new technologies affect load conditions and may cause shifting of peak days and hours over time. Therefore, it is important that customers are cognizant of the months in which their maximum use occurs, and that they endeavor to reduce usage throughout the entirety of those month(s).

NECEC 1-8

Request:

Has the Company estimated its costs to upgrade its billing systems to accommodate the proposed rate design changes? Please provide any early estimates of the costs it will incur to make these changes and the time it would take to implement.

Response:

Please see the Company's response to Division 1-2.

NECEC 1-9

Request:

In several of the Company's responses (including CLF 2-8 and PUC 1-18), the Company cites capacity factors for distributed generation. How do they determine these capacity factors, and how do they plan to determine them going forward? For example, in CLF 2-8, the company uses a 40% capacity factor for wind, but the REG program uses a capacity factor of 21%. Why the difference?

Response:

In the responses referred to above, the Company used the term availability capacity factor, not capacity factor. As explained in the technical session on September 17, 2015, the availability capacity factor is not the same as the capacity factor used in the context of generation. The capacity factor the DG Board uses is the standard definition, in that it compares the nameplate rating for the generation times all hours in a year to the actual amount of generation that is created.

The availability capacity factor is the level of generation the distribution system will be required to carry during the peak load hour in a certain year. Please see the Company's response to PUC 2-1 for a discussion of the availability capacity factor.

Prepared by or under the supervision of: Timothy R. Roughan

NECEC 1-10

Request:

In PUC 1-3, the Company cites the kW currently enrolled in DG and/or Net Metering programs. Are these number cited the nameplate capacity? On page 60 of the Company's testimony, they state that "The Access Fee will be based upon the nameplate capacity of the DG facility, adjusted for expected availability capacity." How will the Company determine the capacity factor for various technologies? If it differs from the capacity factor used by the DG Board, please explain why.

Response:

The numbers cited in PUC 1-3 represent nameplate capacity. The Company is reviewing the amount of exported energy at various peak loading times on its distribution system to determine what percentage of the nameplate capacity is seen and plans to develop an average value similar to the process the ISO-NE used to calculate the amount of solar seen at its system peak hours. Please also see the Company's response to NECEC 1-9.

Prepared by or under the supervision of: Timothy R. Roughan

NECEC 1-11

Request:

In response to CLF 1-10, the Company states that "the savings in the distribution component of the bill produced by the combination of reduced monthly kwh use and placement in a tier with a lower customer charge…approximately equal to the savings produced based on current rates." Over what time frame are these charges "approximately equal"? The Company acknowledges that savings are "not realized immediately", but in what timeframe are they realized?

Response:

The savings produced by the reduction in charges assessed on a per kWh basis are immediate. Under the Company's proposed tiered customer charge design, the savings associated with moving to a lower tier and, therefore, a lower customer charge, will be realized 11 months following the month in which the customer reduces its maximum monthly usage sufficient to move to a lower tier. The savings associated with moving to a lower tier and lower customer charge assumes that the customer is able to manage its use over the following 11 months such that the customer does not qualify for a tier higher than their original tier.

The example provided by the Company in Schedule NG-9, Bates pages 136-137, illustrates the impact of the proposed design on savings realized during the time the customer is charged the customer charge of the higher tier and afterwards when the customer is able to drop down a tier. The monthly savings for the first 12 months would be $5.40 less than the savings under the current rate structure. This is calculated as the difference between the monthly savings under the current design of $92.86 from line 22 of Bates page 136 and the monthly savings under the proposed design of $87.46 from line 21 of Bates page 137 (in the first column labeled "Difference"). After the customer drops to a lower tier by maintaining lower usage, the monthly savings would be $0.71 less than the savings in the current design, which the Company categorized "approximately equal." This is calculated as the difference between the monthly savings under the current design of $92.86 from line 22 of Bates page 136 and the monthly savings under the proposed design of $92.15 from line 21 of Bates page 137 (in the second column labeled "Difference".

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

NECEC 1-12

Request:

Are the "per unit demand-related revenue requirements" mentioned in response to CLF 1-12 unique to generators or for all customers?

Response:

The per unit demand-related revenue requirements included in Schedule NG-10 are calculated by dividing each class's allocated class revenue requirements by the class's non-coincident peak demand. The per unit revenue requirements reflect the aggregate usage characteristics of all customers (this includes all customers who have generation connected to the distribution system) included for each rate class.

NECEC 1-13

Request:

Please provide a line item comparison of a customer's bill under the current rate structure with that customer under the new structure (include all applicable access charges & tiered customer charges) for the following types of customers:

a. G-32 rate class with a behind the meter, net-metered DG project that produces 80% of their gross consumption
b. C-06 rate class with a behind the meter, net metered DG project that produces 80% of their gross consumption.
c. C-06 rate class customer receiving service at their remote meter, virtually net metering a DG project that produces 80% of their gross consumption.
d. G-02 rate class with a behind the meter, net metered DG project that produces 80% of gross consumption
e. G-02 rate class receiving service at their remote meters with a virtually net metered DG project that produces 80% of gross consumption.

Response:

Please see Attachment NECEC 1-13 which includes a comparison of a typical monthly bill for:

a. A Rate G-32 net metering customer with behind the meter generation that produces 80% of the on-site consumption. Please note that this analysis assumes that the generation is not coincident with the load 100% of the time.

b. A Rate C-06 net metering customer with behind the meter generation that produces 80% of the on-site consumption.

c. A Rate C-06 net metered account receiving Renewable Net Metering credits from a remote generator that produces 80% of the on-site load of the net metered account. It is assumed that the Host customer's account is served under Rate C-06.

d. A Rate G-02 net metering customer with behind the meter generation that produces 80% of the on-site consumption. Please note that this analysis assumes that the generation is not coincident with the load 100% of the time.

e. A Rate G-02 net metered account receiving Renewable Net Metering credits from a remote generator that produces 80% of the on-site load of the net metered account. It is assumed that the Host customer's account is served under Rate C-06.

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

Billing Comparison
Rate G-32 Customer w/ Behind the Meter Net Metering
Generation: 80% of On-site Load

1	On-site Consumption:	kWh	200,000
2		kW	500
3	Generation:	kWh	160,000
4			

5	**Monthly Bill**								
6					Current**				Proposed
7									
8	Customer Charge				$825.00				$215.00
9	Distribution Demand Charge	300.0	kW	$4.10	$1,230.00	500.0	kW	$4.90	$2,450.00
10	Distribution Energy Charge	40,000	kWh	$0.00718	$287.20	40,000	kWh	$0.00397	$158.80
11	**Subtotal Distribution**				**$2,342.20**				**$2,823.80**
12	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
13	Transmission Energy Charge	40,000	kWh	$0.00930	$372.00	40,000	kWh	$0.00930	$372.00
14	Transmission Demand Charge	500.0	kW	$3.40	$1,700.00	500.0	kW	$3.40	$1,700.00
15	Transition Energy Charge	40,000	kWh	($0.00201)	($80.40)	40,000	kWh	($0.00201)	($80.40)
16	Energy Efficiency Program Charge	40,000	kWh	$0.00983	$393.20	40,000	kWh	$0.00983	$393.20
17	Renewable Energy Distribution Charge	40,000	kWh	$0.00232	$92.80	40,000	kWh	$0.00232	$92.80
18	RE Growth Program			$17.78	$17.78			$17.78	$17.78
19	Net Metering Credit	-	kWh	($0.07601)	$0.00	-	kWh	($0.07280)	$0.00
20	**Subtotal Other Delivery Service**				**$2,496.11**				**$2,496.11**
21	Standard Offer Charge	40,000	kWh	$0.06154	$2,461.60	40,000	kWh	$0.06154	$2,461.60
22	Renewable Egy Std Charge	40,000	kWh	$0.00294	$117.60	40,000	kWh	$0.00294	$117.60
23	**Subtotal Supply Service**				**$2,579.20**				**$2,579.20**
24									
25	**Subtotal before GET**				**$7,417.51**				**$7,899.11**
26									
27	Gross Earnings Tax			4%	$309.06			4%	$329.13
28									
29	**Total Bill including GET**				**$7,726.57**				**$8,228.24**
30									
31								Difference	**$501.67**
32								Percent Difference	6.5%

**Based on rates in effect as of July 1, 2015

Billing Comparison
Rate C-06 Customer w/ Behind the Meter Net Metering
Generation: 80% of On-site Load

1	On-site Consumption:	kWh	1,000						
2		kW	n/a						
3	Generation:	kWh	800						
4									
5	**Monthly Bill**				Current**				Proposed
6									
7									
8	Customer Charge (Tier 2)				$10.00				$11.75
9	Distribution Energy Charge	200	kWh	$0.03668	$7.34	200	kWh	$0.03039	$6.08
10	**Subtotal Distribution**				**$17.34**				**$17.83**
11	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
12	Transmission Energy Charge	200	kWh	$0.02072	$4.14	200	kWh	$0.02072	$4.14
13	Transition Energy Charge	200	kWh	($0.00201)	($0.40)	200	kWh	($0.00201)	($0.40)
14	Energy Efficiency Program Charge	200	kWh	$0.00983	$1.97	200	kWh	$0.00983	$1.97
15	Renewable Energy Distribution Charge	200	kWh	$0.00232	$0.46	200	kWh	$0.00232	$0.46
16	RE Growth Program			$0.26	$0.26			$0.26	$0.26
17	Net Metering Credit	-	kWh	($0.14230)	$0.00	-	kWh	($0.13601)	$0.00
18	**Subtotal Other Delivery Service**				**$7.16**				**$7.16**
19	Standard Offer Charge	200	kWh	$0.08691	$17.38	200	kWh	$0.08691	$17.38
20	Renewable Ege Std Charge	200	kWh	$0.00294	$0.59	200	kWh	$0.00294	$0.59
21	**Subtotal Supply Service**				**$17.97**				**$17.97**
22									
23	**Subtotal before GET**				**$42.47**				**$42.96**
24									
25	Gross Earnings Tax			4%	$1.77			4%	$1.79
26									
27	**Total Bill including GET**				**$44.24**				**$44.75**
28									
29								Difference	**$0.51**
30								Percent Difference	1.2%

**Based on rates in effect as of July 1, 2015

Billing Comparison
Rate C-06 Customer w/ Remote Net Metering
Generation: 80% of Net Metered Account On-site Load

1	On-site Consumption:	kWh	1,000						
2		kW	n/a						
3	Generation:	kWh	800						
4									
5	**Monthly Bill**								
6					Current**				Proposed
7	**HOST CUSTOMER (Rate C-06)**								
8	Customer Charge (Tier 1)				$10.00				$10.50
9	Access Fee (10kW Solar Project)*			n/a		4.0	kW	$5.00	$20.00
10	Distribution Energy Charge	-	kWh	$0.03668	$0.00	-	kWh	$0.03039	$0.00
11	**Subtotal Distribution**				**$10.00**				**$30.50**
12	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
13	Transmission Energy Charge	-	kWh	$0.02072	$0.00	-	kWh	$0.02072	$0.00
14	Transition Energy Charge	-	kWh	-$0.00201	$0.00	-	kWh	($0.00201)	$0.00
15	Energy Efficiency Program Charge	-	kWh	$0.00983	$0.00	-	kWh	$0.00983	$0.00
16	Renewable Energy Distribution Charge	-	kWh	$0.00232	$0.00	-	kWh	$0.00232	$0.00
17	RE Growth Program			$0.26	$0.26			$0.26	$0.26
18	Net Metering Credit	800	kWh	($0.14230)	($113.84)	800	kWh	($0.13601)	($108.81)
19	**Subtotal Other Delivery Service**				**($112.85)**				**($107.82)**
20	Standard Offer Charge	-	kWh	$0.08691	$0.00	-	kWh	$0.08691	$0.00
21	Renewable Egy Std Charge	-	kWh	$0.00294	$0.00	-	kWh	$0.00294	$0.00
22	**Subtotal Supply Service**				**$0.00**				**$0.00**
23									
24	**Subtotal before GET**				**($102.85)**				**($77.32)**
25									
26	Gross Earnings Tax			4%	$0.46			4%	$1.31
27									
28	**Total Bill including GET**				**($102.39)**				**($76.01)**
29									
30									
31					Current				Proposed
32	**NET METERED ACCOUNT (Rate C-06)**								
33	Customer Charge (Tier 3)				$10.00				$17.25
34	Distribution Energy Charge	1,000	kWh	$0.03668	$36.68	1,000	kWh	$0.03039	$30.39
35	**Subtotal Distribution**				**$46.68**				**$47.64**
36	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
37	Transmission Energy Charge	1,000	kWh	$0.02072	$20.72	1,000	kWh	$0.02072	$20.72
38	Transition Energy Charge	1,000	kWh	($0.00201)	($2.01)	1,000	kWh	($0.00201)	($2.01)
39	Energy Efficiency Program Charge	1,000	kWh	$0.00983	$9.83	1,000	kWh	$0.00983	$9.83
40	Renewable Energy Distribution Charge	1,000	kWh	$0.00232	$2.32	1,000	kWh	$0.00232	$2.32
41	RE Growth Program			$0.26	$0.26			$0.26	$0.26
42	**Subtotal Other Delivery Service**				**$31.85**				**$31.85**
43	Standard Offer Charge	1,000	kWh	$0.08691	$86.91	1,000	kWh	$0.08691	$86.91
44	Renewable Egy Std Charge	1,000	kWh	$0.00294	$2.94	1,000	kWh	$0.00294	$2.94
45	**Subtotal Supply Service**				**$89.85**				**$89.85**
46									
47	**Subtotal before GET**				**$168.38**				**$169.34**
48									
49	Gross Earnings Tax			4%	$7.02			4%	$7.06
50									
51	**Total Bill including GET**				**$175.40**				**$176.40**
52									
53	Transferred Credit				**($102.39)**				**($76.01)**
54									
55	Net Monthly Bill				**$73.01**				**$100.39**
56									
57	**Summary:**								
58	Host Customer				($102.39)				($76.01)
59	Net Metered Customer				$175.40				$176.40
60									
61	Net Monthly Bill				$73.01				$100.39
62									
63									
64								Difference	$27.38
65								Percent Difference	37.5%

* Access fee is calculated by multiplying the Nameplate Capacity x 40%
** Based on rates in effect as of July 1, 2015

Billing Comparison
Rate G-02 Customer w/ Behind the Meter Net Metering
Generation: 80% of On-site Load

1	On-site Consumption:	kWh	20,000
2		kW	50
3	Generation:	kWh	16,000
4			

5	**Monthly Bill**								
6					Current**				Proposed
7									
8	Customer Charge				$135.00				$75.00
9	Distribution Demand Charge	40.0	kW	$5.23	$209.20	50.0	kW	$5.98	$299.00
10	Distribution Energy Charge	4,000	kWh	$0.00687	$27.48	4,000	kWh	$0.00506	$20.24
11	**Subtotal Distribution**				**$371.68**				**$394.24**
12	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
13	Transmission Energy Charge	4,000	kWh	$0.00894	$35.76	4,000	kWh	$0.00894	$35.76
14	Transmission Demand Charge	50.0	kW	$3.02	$151.00	50.0	kW	$3.02	$151.00
15	Transition Energy Charge	4,000	kWh	($0.00201)	($8.04)	4,000	kWh	($0.00201)	($8.04)
16	Energy Efficiency Program Charge	4,000	kWh	$0.00983	$39.32	4,000	kWh	$0.00983	$39.32
17	Renewable Energy Distribution Charge	4,000	kWh	$0.00232	$9.28	4,000	kWh	$0.00232	$9.28
18	RE Growth Program			$2.46	$2.46			$2.46	$2.46
19	Net Metering Credit	-	kWh	($0.10071)	$0.00	-	kWh	($0.09890)	$0.00
20	**Subtotal Other Delivery Service**				**$230.51**				**$230.51**
21	Standard Offer Charge	4,000	kWh	$0.08691	$347.64	4,000	kWh	$0.08691	$347.64
22	Renewable Egy Std Charge	4,000	kWh	$0.00294	$11.76	4,000	kWh	$0.00294	$11.76
23	**Subtotal Supply Service**				**$359.40**				**$359.40**
24									
25	**Subtotal before GET**				**$961.59**				**$984.15**
26									
27	Gross Earnings Tax			4%	$40.07			4%	$41.01
28									
29	**Total Bill including GET**				**$1,001.66**				**$1,025.16**
30									
31								Difference	**$23.50**
32								Percent Difference	2.3%

**Based on rates in effect as of July 1, 2015

Billing Comparison
Rate G-02 Customer w/ Remote Net Metering
Generation: 80% of Net Metered Account On-site Load

1	On-site Consumption:	kWh	20,000						
2		kW	50						
3	Generation:	kWh	16,000						
4									
5	**Monthly Bill**								
6					Current**				Proposed
7	**HOST CUSTOMER (Rate C-06)**								
8	Customer Charge (Tier 1)				$10.00				$10.50
9	Access Fee (15kW Solar Project)*			n/a		6.0	kW	$5.00	$30.00
10	Distribution Energy Charge	-	kWh	$0.03668	$0.00	-	kWh	$0.03039	$0.00
11	**Subtotal Distribution**				**$10.00**				**$40.50**
12	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
13	Transmission Energy Charge	-	kWh	$0.02072	$0.00	-	kWh	$0.02072	$0.00
14	Transition Energy Charge	-	kWh	-$0.00201	$0.00	-	kWh	($0.00201)	$0.00
15	Energy Efficiency Program Charge	-	kWh	$0.00983	$0.00	-	kWh	$0.00983	$0.00
16	Renewable Energy Distribution Charge	-	kWh	$0.00232	$0.00	-	kWh	$0.00232	$0.00
17	RE Growth Program			$0.26	$0.26			$0.26	$0.26
18	Net Metering Credit	16,000	kWh	($0.14230)	($2,276.80)	16,000	kWh	($0.13601)	($2,176.16)
19	**Subtotal Other Delivery Service**				**($2,275.81)**				**($2,175.17)**
20	Standard Offer Charge	-	kWh	$0.08691	$0.00	-	kWh	$0.08691	$0.00
21	Renewable Egy Std Charge	-	kWh	$0.00294	$0.00	-	kWh	$0.00294	$0.00
22	**Subtotal Supply Service**				**$0.00**				**$0.00**
23									
24	**Subtotal before GET**				**($2,265.81)**				**($2,134.67)**
25									
26	Gross Earnings Tax			4%	$0.46			4%	$1.73
27									
28	**Total Bill including GET**				**($2,265.35)**				**($2,132.94)**
29									
30									
31					Current				Proposed
32	**NET METERED ACCOUNT (Rate G-02)**								
33	Customer Charge				$135.00				$75.00
34	Distribution Demand Charge	40.0	kW	$5.23	$209.20	50.0	kW	$5.98	$299.00
35	Distribution Energy Charge	20,000	kWh	$0.00687	$137.40	20,000	kWh	$0.00506	$101.20
36	**Subtotal Distribution**				**$481.60**				**$475.20**
37	LIHEAP Charge			$0.73	$0.73			$0.73	$0.73
38	Transmission Energy Charge	20,000	kWh	$0.00894	$178.80	20,000	kWh	$0.00894	$178.80
39	Transmission Demand Charge	50.0	kW	$3.02	$151.00	50.0	kW	$3.02	$151.00
40	Transition Energy Charge	20,000	kWh	($0.00201)	($40.20)	20,000	kWh	($0.00201)	($40.20)
41	Energy Efficiency Program Charge	20,000	kWh	$0.00983	$196.60	20,000	kWh	$0.00983	$196.60
42	Renewable Energy Distribution Charge	20,000	kWh	$0.00232	$46.40	20,000	kWh	$0.00232	$46.40
43	RE Growth Program			$2.46	$2.46			$2.46	$2.46
44	**Subtotal Other Delivery Service**				**$535.79**				**$535.79**
45	Standard Offer Charge	20,000	kWh	$0.08691	$1,738.20	20,000	kWh	$0.08691	$1,738.20
46	Renewable Egy Std Charge	20,000	kWh	$0.00294	$58.80	20,000	kWh	$0.00294	$58.80
47	**Subtotal Supply Service**				**$1,797.00**				**$1,797.00**
48									
49	**Subtotal before GET**				**$2,814.39**				**$2,807.99**
50									
51	Gross Earnings Tax			4%	$117.27			4%	$117.00
52									
53	**Total Bill including GET**				**$2,931.66**				**$2,924.99**
54									
55	Transferred Credit				**($2,265.35)**				**($2,132.94)**
56									
57	Net Monthly Bill				**$666.31**				**$792.05**
58									
59	**Summary:**								
60	Host Customer				**($2,265.35)**				**($2,132.94)**
61	Net Metered Customer				**$2,931.66**				**$2,924.99**
62									
63	Net Monthly Bill				**$666.31**				**$792.05**
64									
65									
66								Difference	**$125.74**
67								Percent Difference	18.9%

*Access fee is calculated by taking Nameplate Capacity x 40%
** Based on rates in effect as of July 1, 2015