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CONNECTICUT GREEN BANK

March 9, 2016

A Message from the President and CEO

This second evaluation of the Residential Solar Investment Program (RSIP) conducted by The Cadmus Group for the Connecticut Green Bank is focused on RSIP cost-effectiveness. The enclosed report, "Cost-Effectiveness Assessment of the Residential Solar Investment Program" documents the findings of this evaluation, which concludes that RSIP is cost-effective from multiple perspectives including for program participants and the efficient use of program funds.

RSIP provides two types of incentives for residential solar PV projects, an Expected Performance Based Buydown (EPBB) or upfront rebate provided for the customer through the installer, and a Performance Based Incentive for third party owned systems. This evaluation spans incentive steps 1 through 7, for which incentives decreased from $2.45/W to $0.54/W for the EPBB and $0.30/kWh to $0.064/kWh for the PBI. During this time, over 12,200 projects or 91.3 MW had been approved, were in progress or had been completed through RSIP.

RSIP reached its original legislative target of 30 MW eight years ahead of schedule in July 2014. On July 2, 2015, the Governor and Connecticut legislature passed an expanded RSIP target of 300 MW by 2022, along with creation of Solar Home Renewable Energy Credits (SHRECs) as a funding source for the program. Recent milestones also include:

- RSIP step 9 began February 1, 2016, with incentive levels at $0.513/W for EPBB and $0.046/kWh – an equivalent ZREC price of between $20-$25.
- As of March 4, 2016, RSIP reached over 16,000 projects or 121 MW in approved or later statuses, while average installed costs were $3.36/W thus far for calendar year 2016 (excluding those projects where financing costs for some third party ownership installers are included as part of the total system cost).
- Federal incentives including the 30% investment tax credit and MACRS were extended in December 2015.
- Along with www.EnergizeCT.com, www.GoSolarCT.com is serving as a trusted information resource that the Connecticut Green Bank is developing for the residential solar PV market in Connecticut.
- The Green Bank offers the Smart-E residential financing product, providing low interest loans for most residential energy improvements including solar PV and energy efficiency measures. Lower rates are offered for Smart-E technology bundles that combine two or more qualifying measures.
- We continue to see developments in emerging technologies such as energy storage that along with solar PV, energy efficiency, and demand response hold promise to provide comprehensive solutions to meet the energy needs of Connecticut customers while providing broader benefits to the electricity system.
- The Green Bank completed its second Comprehensive Annual Financial Report (CAFR), for FY 2015 (see www.ctgreenbank.com, "About Us").

We thank all our stakeholders for your strong support of the Residential Solar Investment Program and the Connecticut Green Bank as we continue working to make clean energy more affordable and accessible to consumers.

Bryan T. Garcia
President and CEO

Cost-Effectiveness Assessment of the Residential Solar Investment Program

March 8, 2016

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Introduction

A report capturing the findings of a first evaluation[1] of the Connecticut Green Bank Residential Solar Investment Program (RSIP) was submitted to the state of Connecticut legislature at the beginning of 2014 to provide an update on progress made toward the 30 MW[2] by 2022 goal specified in PA 11-80.[3] The first evaluation covered the time period from March 2012 through June 2013, by which time 10 MW of projects had been approved, in progress, or completed through RSIP. This second evaluation is focused on assessing the cost-effectiveness of RSIP overall, from Step 1 beginning in March 2012 through Step 7 ending in August 2015. As of August 12, 2015, the cut-off date for the data included in this evaluation, 91.3 MW of solar PV projects had been approved, in progress, or completed through RSIP.

Cadmus and the Connecticut Green Bank are grateful for support from:

- Joseph Swift of Eversource Energy in providing input, guidance and modeling assistance on cost-effectiveness benchmarking for utility-administered energy efficiency programs.
- Chris Kramer of Energy Futures Group, Financing Consultant to the Connecticut Energy Efficiency Board (EEB)[4], and Glenn Reed and Richard Faesy of Energy Futures Group, Residential Consultants to the EEB, for providing guidance, information and resources on cost-effectiveness benchmarking for utility-administered energy efficiency programs, and for feedback on this report.
- Jeff Schlegel, Senior Technical Consultant to the EEB, for feedback on the report.
- Les Tumidaj, Commercial and Industrial Consultant to the EEB, for feedback on the report.
- Paul Horowitz of PAH Associates, for feedback on the report.

While reviewer comments were incorporated into the report as much as possible, these acknowledgements do not imply that all reviewer comments were addressed nor that the authors and reviewers agree on all assumptions and methodological decisions.

To provide results that would be meaningful to policymakers looking at cost-effectiveness broadly for all programs in Connecticut, the aim was to conduct this evaluation using assumptions as consistent as possible with those used in the analysis of the energy efficiency programs delivered by Connecticut's two investor-owned utilities, Eversource Energy and the United Illuminating Company (UI). However,

[1] "Residential Solar Investment Program Evaluation," Shawn Shaw, Danielle Kolp, Mary Knipe, Ryan Fahey, Kathleen Higgins, The Cadmus Group, January 28, 2015. http://www.ctgreenbank.com/wp-content/uploads/2016/02/RSIP_Evaluation_I_Final_Report_and_cvr_ltr.pdf

[2] All instances of MW or kW referenced in this report are provided in Watts-DC (direct current) or equivalently, Watts – STC (standard test conditions), unless stated otherwise.

[3] The text of PA 11-80 can be found here: https://www.cga.ct.gov/2011/act/pa/2011PA-00080-R00SB-01243-PA.htm.

[4] http://www.energizect.com/about/eeboard

there remained differences between the processes used to derive the solar PV cost-effectiveness ratios in this report and those used by utilities to calculate cost-effectiveness for energy efficiency. As a result, although solar PV and energy efficiency[5] are both cost-effective, a direct comparison is not presented in this report.

The report section “Cost-Effectiveness of Energy Efficiency” references cost-effectiveness results for energy efficiency and explains some of the differences in the assumptions and methodologies used to determine solar PV and energy efficiency benefit/cost ratios. The energy efficiency results are also included in the report section “Cost-Effectiveness of Bundled Technologies” in which an example calculation illustrates that one can combine measures that are cost-effective (e.g., solar PV and energy efficiency) with those not yet cost-effective (e.g., energy storage) to encourage adoption of more comprehensive energy solutions for participants while maintaining overall project cost-effectiveness.

[5] Energy efficiency cost-effectiveness ratios referenced in this report are from the 2016-2018 Electric and Natural Gas Conservation and Load Management (CL&M) plan filed with the Connecticut Department of Energy and Environmental Protection on October 1, 2015, available at http://www.energizect.com/about/eeboard/plans. The Eversource 2016 cost-effectiveness ratios for residential energy efficiency programs are provided for reference in the section of this report titled “Cost-Effectiveness of Energy Efficiency.”

Executive Summary

Cadmus evaluated the cost-effectiveness of the Connecticut Green Bank's (the Green Bank, or CGB) Residential Solar Investment Program (RSIP). The RSIP, launched in March 2012, supports the installation of residential solar photovoltaic (PV) systems in Connecticut by providing direct purchase and third-party ownership incentives, as well as marketing and educational support for the industry, qualification of contractors and third party system owners, and inspection of solar PV systems. This evaluation assessed the cost-effectiveness of RSIP from incentive step 1 beginning in March 2012 through incentive step 7 ending in August 2015.[6] As of August 12, 2015, the cut-off date for the data included in this evaluation, 91.3 MW of RSIP solar PV projects were approved, in progress, or completed.

The key findings from this study are:

- RSIP is cost-effective from the perspective of program participants, the Connecticut Green Bank, from a total resource perspective, and for society as a whole.
- RSIP has increasingly made efficient use of program funds by reducing incentives while supporting market growth through financing, marketing, outreach and education.
- RSIP benefits sufficiently outweigh costs to allow for bundling of residential solar PV with emerging technologies such as energy storage, while maintaining cost-effectiveness.[7]

Using the five accepted cost-effectiveness tests adopted for energy efficiency programs, as defined in the California Standard Practice Manual[8], Cadmus evaluated the cost-effectiveness of the RSIP from the following perspectives:[9]

- Total Resource Cost Test (TRC)
- Program Administrator Cost Test (PACT), also called the Utility Cost Test (UCT)[10]
- Customer/Participant Cost Test (PCT)
- Ratepayer Impact Measure Test (RIM)
- Societal Cost Test (SCT)

[6] RSIP incentives levels are provided in the Methodology section of this report.
[7] The technology bundling example provided in this study includes residential solar PV (represented by RSIP) and energy efficiency (represented by Eversource Energy's Home Energy Solutions Program), both of which are cost-effective, leveraging the benefits of both technologies to enable deployment of emerging technologies such as energy storage that are not yet cost-effective.
[8] "California Standard Practice Manual. Economic Analysis of Demand-Side Programs and Projects." October 2001, first published in 1983. http://cpuc.ca.gov, or http://sustainca.org/content/california_standard_practice_manual_economic_analysis_demand_side_programs_and_projects.
[9] See the Overview section for definitions of the tests.
[10] Since the Program administrator is not the utility in this case, but rather the Connecticut Green Bank, this evaluation will refer to this test as the PACT.

In addition to these tests, Cadmus calculated the results for the Green Bank (CGB) Objective Function (OF), an indicator of the efficiency of electric generation created by RSIP as measured by energy delivered to dollars invested. Summary Tables 1 and 2 below present cost-effectiveness results for the five standard tests, as well as results for the CGB OF, for the RSIP overall and for program steps 1 through 7, associated with steadily decreasing incentives.

Table 1. RSIP Cost-Effectiveness Results for the Five Standard Tests and the Connecticut Green Bank Objective Function (CGB OF)

CGB RSIP 2012-2015	Residential Solar PV Capacity (MW)[11]	TRC	PACT	PCT	RIM	SCT	CGB OF (kWh/$ invested)
Steps 1 & 2	7.4	1.44	1.50	1.72	0.40	1.64	18.1
Step 3	13.3	1.59	2.07	1.80	0.43	1.81	25.7
Step 4	20.5	1.70	2.63	1.83	0.45	1.78	33.4
Step 5	14.8	1.74	3.57	1.80	0.47	1.72	45.3
Step 6	14.0	1.76	5.16	1.80	0.49	1.76	67.0
Step 7	21.4	1.80	6.47	1.80	0.50	1.75	83.9
Total	91.3	1.70	3.05	1.80	0.46	1.75	38.7

Table 2. RSIP Total Benefits, Costs, and Net Benefits for the Five Standard Tests

CGB RSIP 2012-2015	TRC	PACT	PCT	RIM	SCT
Installed Capacity (MW[12])	91.3	91.3	91.3	91.3	91.3
NPV Benefits	$618,994,562	$210,410,423	$596,514,388	$210,410,423	$685,462,023
NPV Costs	$364,837,887	$69,057,692	$331,819,540	$455,144,337	$390,979,712
NPV Net Benefits	$254,156,675	$141,352,731	$264,694,849	-$244,733,913	$294,482,311
Net Benefits/MW	$2,780,707.60	$1,546,528.79	$2,896,004.91	-$2,677,613.93	$3,221,907.12
B/C Ratio	1.70	3.05	1.80	0.46	1.75

[11] Step 7 projects included in the study as of August 12, 2015 amounted to 21.4 MW, including projects in approved or later project statuses. The Step 7 end date was August 7, 2015; however not all step 7 projects had been approved as of August 7 or even August 12 when the data were analyzed for this study. As of January 11, 2016, step 7 capacity was 21.3 MW, so projects that had not yet been approved as of August 12 ended up roughly balancing out with projects that had been approved by August 12 but were later cancelled.

[12] Solar PV modules convert solar radiation into direct current (DC) electricity. Solar PV capacity (kW or MW) referenced in this report are provided in Watts-DC or equivalently, Watts – STC (standard test conditions), unless otherwise specified. Capacity can also be provided as Watts-AC (alternating current) which is the wattage available for use by household AC loads such as lighting and appliances. The conversion factor from Watts-DC to Watts-AC is typically in the range of 70%-83%, depending on system losses. The National Renewable Energy Laboratory PVWatts Calculator (pvwatts.nrel.gov) uses a default DC to AC derate factor of 82.56% which comes from an 86% derate (i.e. 14% losses) multiplied by 96% inverter efficiency. RSIP incentives are based on another rating, Watts-PTC (PVUSA Test Conditions), explained in the Methodology section.

The Green Bank RSIP is a cost-effective program, producing significantly higher benefits than costs.[13] RSIP passed all cost-effectiveness tests except the RIM which many programs including most energy efficiency programs do not typically pass[14]. Based on analysis of these cost-effectiveness metrics, RSIP is delivering 0.46 to 3.05 times as many benefits as costs, depending on the cost-effectiveness test used (see Tables 1 and 2). From a program perspective (PACT), RSIP delivers triple the impact of its investment, $3.05 in benefits for every dollar invested by the Green Bank. The PACT provides net benefits of approximately $141 million. The PACT benefits are lower than for other ratios such as the TRC and PCT because the PACT benefits do not include federal tax benefits and do not include participant bill savings. On the cost side, the PACT costs are lower than for the TRC and PCT because participant measure costs are not included in the PACT. Over the RSIP's life[15], the program also contributes net benefits of approximately $265 million to program participants (PCT), $254 million from a total resource perspective (TRC), and $294 million to society as a whole (SCT).

The Connecticut Green Bank Objective Function provides another metric demonstrating efficient use of RSIP funds, with increasing energy produced for every dollar invested, as the program has progressed from steps 1 through 7 (see Table 3).

Table 3. RSIP Results for Connecticut Green Bank Objective Function

CGB RSIP Incentive Step (2012-2015)	Residential Solar PV Capacity (MW)	Lifetime kWh	Program Costs	CGB OF (kWh/$)
Steps 1 & 2	7.4	225,385,736	$12,435,693	18.1
Step 3	13.3	405,346,549	$15,784,621	25.7
Step 4	20.5	607,500,605	$18,200,235	33.4
Step 5	14.8	428,600,431	$9,467,372	45.3
Step 6	14.0	403,698,026	$6,021,396	67.0
Step 7	21.4	600,041,849	$7,148,375	83.9
Total	91.3	2,670,573,196	$69,057,692	38.7

The Green Bank increasingly makes effective use of RSIP funds, supporting strong growth in the solar market while simultaneously reducing RSIP incentives. As shown by the increasing Green Bank Objective Function and increasing PACT results over the program's life, coupled with relatively flat customer economics (represented by the PCT), the Green Bank has supported strong growth while

[13] The RSIP overall is cost effective for all tests (benefit/cost ratio greater than one), as well as for individual incentive steps 1-7, except on the RIM test for which energy efficiency programs also typically do not pass.
[14] The RIM test accounts for lost utility revenue and assumes that the cost is redistributed among all ratepayers. More often than not, measures that reduce the utility's sale of electricity will fail to pass the RIM test, regardless of societal or total resource cost-effectiveness. Load shifting and demand reduction programs are more likely to pass the RIM test.
[15] Solar PV system lifetimes are assumed to be 25 years. NREL provides a range of 25 to 40 years for the useful life of a photovoltaic system, http://www.nrel.gov/analysis/tech_footprint.html.

simultaneously reducing public subsidies and maintaining customer economics over the program's life. As the cost of solar PV has decreased[16], the Green Bank has reduced incentives to make them available to a larger number of projects. The increase in the PACT from 1.5 in Steps 1&2 to 6.47 in Step 7 amounts to more than a four-fold increase in the cost-effectiveness ratio, and the lower Step 7 incentive does not appear to have impeded market growth. Additionally, while incentives decrease and the PACT increases, net benefits/MW for the PACT are maintained over the program steps. See Table 4, below.

Table 4. RSIP PACT Results and Comparison to PCT

CGB RSIP 2012-2015	Installed Capacity (MW)	PACT Benefits	PACT Costs	Net PACT Benefits	Net Benefits/ MW	PACT Benefit/ Cost Ratio	PCT Benefit/ Cost Ratio
Steps 1 & 2	7.4	$18,646,724	$12,435,693	$6,211,031	**$839,329**	**1.50**	**1.72**
Step 3	13.3	$32,714,259	$15,784,621	$16,929,638	**$1,272,905**	**2.07**	**1.80**
Step 4	20.5	$47,901,194	$18,200,235	$29,700,959	**$1,448,827**	**2.63**	**1.83**
Step 5	14.8	$33,822,171	$9,467,372	$24,354,799	**$1,645,594**	**3.57**	**1.80**
Step 6	14	$31,078,515	$6,021,396	$25,057,119	**$1,789,794**	**5.16**	**1.80**
Step 7	21.4	$46,247,561	$7,148,375	$39,099,186	**$1,827,065**	**6.47**	**1.80**
Total	**91.3**	**$210,410,423**	**$69,057,692**	**$141,352,731**	**$1,546,529**	**3.05**	**1.80**

Taken together, the traditional cost-effectiveness tests and the Green Bank Objective Function tell a consistent story – that RSIP increasingly makes efficient use of program funds from step 1 through step 7, as represented by PACT and Green Bank Objective Function results, while the PCT which reflects the benefit/cost ratio for the participant stays level.

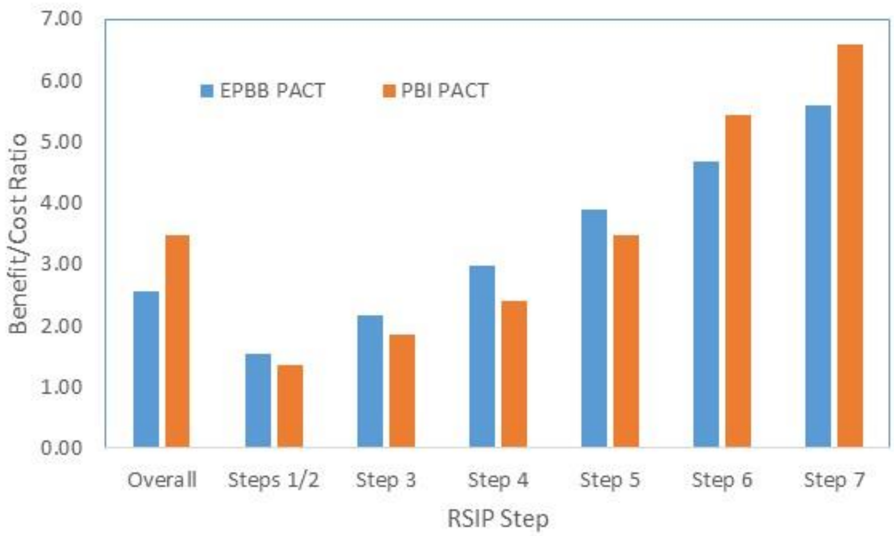
RSIP provides two types of incentives, the Expected Performance Based Buydown (EPBB) and the Performance Based Incentive (PBI).[17] Generally, the PBI proves more cost effective than the EPBB. See Figure 1 below for the PACT results shown separately for the EPBB and PBI. Though both RSIP incentive types prove cost-effective, the PBI element exhibits a higher benefit/cost ratio on all tests except for the SCT. The EPBB's slightly lower ratios partially result from leased PV systems taking advantage of

[16] The average installed cost of solar PV systems supported through the RSIP (as reported by RSIP contractors and third party system owners) has fallen from $4.54/W in Steps 1&2 to $4.29/W in Step 7 for EPBB projects, and $4.91/W in Steps 1&2 to $4.39/W in Step 7.

[17] For the EPBB, the homeowner owns the PV system and the installer receives the incentive payment from the Green Bank on behalf of the customer who has benefited from a buydown or reduction in the cost of the system. Participants also receive a 30% federal investment tax credit (ITC). For PBI, a third-party system owner owns the PV system, and leases it (and its associated generation) to the homeowner, either for a monthly payment or an energy-based charge (i.e., a power purchase agreement). Third-party system owners may utilize two federal tax incentives, the ITC and accelerated depreciation.

accelerated depreciation under the MACRS[18] program, which is not available to direct ownership PV customers. Notably, the EPBB proved initially more cost-effective for the PACT, but the PBI surpassed it in Step 6 of the program.

Figure 1. PACT Results for RSIP Incentive Types, by Step



Both RSIP and energy efficiency programs are cost-effective. To provide results that would be meaningful to policymakers looking at cost-effectiveness broadly for all programs in Connecticut, the aim was to conduct this evaluation using assumptions as consistent as possible with those used in examining the energy efficiency programs delivered by the Connecticut utilities. However, there are differences between the methodologies used to derive the solar PV cost-effectiveness ratios in this report and those used by utilities to calculate cost-effectiveness for energy efficiency. Therefore, while solar PV and energy efficiency are both cost-effective, a direct comparison is not presented in this report.

The report section "Cost-Effectiveness of Energy Efficiency" presents cost-effectiveness ratios for Eversource Energy's residential energy efficiency programs and explains some of the differences in the assumptions and methodologies used to determine solar PV and energy efficiency benefit/cost ratios. The energy efficiency cost-effectiveness ratios are also included in the report section "Cost-Effectiveness of Bundled Technologies" in which an example calculation illustrates that one can combine measures that are cost-effective (e.g., solar PV and energy efficiency) with those not yet cost-effective (e.g., energy storage) to encourage adoption of more comprehensive energy solutions for participants while

[18] MACRS (Modified Accelerated Cost Recovery System) is a Federal tax benefit that allows businesses to claim the depreciated value of solar assets as a tax deduction over a five year period. For more information: http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs.

maintaining cost-effectiveness. Table 5 presents cost-effectiveness ratios for Eversource's energy efficiency programs, almost all of which are cost-effective.[19]

Table 5. Eversource 2016 Residential Energy Efficiency[20] Program Cost-Effectiveness.

Program, Year		Test	Benefits	Costs	Net Benefits	Ratio
EE 2016 Eversource	Residential Total	TRC	$186,853,379	$76,049,054	$110,804,325	2.46
		PACT	$89,622,927	$40,686,706	$48,936,221	2.20
		M-PACT	$133,786,974	$56,458,769	$77,328,205	2.37
	Residential Retail Products	TRC	$82,271,005	$24,792,006	$57,478,999	3.32
		PACT	$51,489,640	$13,622,165	$37,867,475	3.78
		M-PACT	$51,489,640	$13,622,165	$37,867,475	3.78
	Home Energy Solutions (HES)	TRC	$62,298,317	$19,090,656	$43,207,661	3.26
		PACT	$17,138,430	$9,467,560	$7,670,870	1.81
		M-PACT	$51,721,547	$17,965,248	$33,756,299	2.88
	HES HVAC	TRC	$5,794,248	$6,679,885	($885,637)	0.87
		PACT	$3,982,333	$2,000,000	$1,982,333	1.99
		M-PACT	$3,982,333	$2,000,000	$1,982,333	1.99
	HES Income Eligible	TRC	$22,914,543	$17,713,445	$5,201,098	1.29
		PACT	$8,853,029	$10,728,336	($1,875,307)	0.83
		M-PACT	$16,873,190	$17,459,712	($586,522)	0.97
	New Construction	TRC	$6,442,405	$4,773,062	$1,669,343	1.35
		PACT	$3,198,174	$1,868,646	$1,329,528	1.71
		M-PACT	$4,758,944	$2,411,645	$2,347,299	1.97
	Behavior	TRC	$7,132,861	$3,000,000	$4,132,861	2.38
		PACT	$4,961,321	$3,000,000	$1,961,321	1.65
		M-PACT	$4,961,321	$3,000,000	$1,961,321	1.65

[19] A few exceptions are: the TRC ratio for HES HVAC, and the UCT/PACT and modified UCT/PACT ratios for HES Income Eligible. The HVAC measure costs tend to be higher than those for other EE programs. For the HES Income Eligible program, incentives typically cover 100% of the measure costs, resulting in lower UCT/PACT ratios.

[20] As provided in the 2016-2018 Electric and Natural Gas Conservation and Load Management (CL&M) plan filed with the Connecticut Department of Energy and Environmental Protection on October 1, 2015, available at http://www.energizect.com/about/eeboard/plans (the numbers could be updated before the Plan is finalized). The energy efficiency numbers shown here are from Table B1, Eversource CT Electric – Costs and Benefits 2016. The PACT and the M-PACT correspond to the Electric Utility Cost Test and the Modified Utility Cost Test from the CL&M Plan. The electric utility cost test includes electric benefits and costs, while the modified utility cost test includes oil and propane savings and costs. The electric utility cost test is used as an example for combining with solar PV benefits and costs (in the next section on technology bundling) but both tests are shown here to illustrate that the EE measures have non-electric impacts (that usually increase the ratios). Also, note that the residential EE programs have been designed to maximize not just electricity, but all fuel savings, including oil, gas and propane. If the technology bundle considered in the next section included non-electric impacts, the M-PACT could be more appropriate for use in calculating the cost-effectiveness of the technology bundle.

The RSIP could incorporate residential energy storage, while remaining cost-effective. Although energy storage technologies, in the current Connecticut market, do not offer customers a financial return on investment, energy storage is desirable from an energy resilience standpoint and, as ancillary service markets develop, may offer attractive financial gains in the future, while also providing grid modernization benefits. With the Cadmus evaluation showing a PACT ratio for RSIP Step 7 approaching 7 to 1, there is an opportunity to deploy a suite of technologies along with solar PV that would provide more comprehensive energy solutions for participants and benefits to the grid while still maintaining overall cost-effectiveness. The Green Bank asked Cadmus to assess the cost-effectiveness of a potential technology combination for a typical residential customer in Connecticut, bundling solar PV, energy efficiency, and energy storage into a single resource and calculating the cost-effectiveness of the resulting resource mix. The Green Bank also asked Cadmus to comment on the potential impact of smart metering technologies, for which further discussion is provided in the body of the report.

Table 6 presents benefits, costs, and net benefits for the PACT, TRC and PCT ratios for RSIP Step 7, the Home Energy Solutions (HES) Program[21], RSIP plus HES, energy storage[22], and two technology bundles: RSIP plus storage, and RSIP plus HES plus storage. The resulting PACT, TRC, and PCT ratios for the two technology bundles that include energy storage are all greater than unity because RSIP and HES are both cost-effective and there is sufficient extra benefit with RSIP and HES to offset the additional cost of energy storage. Note that the benefits of energy storage were assumed to be zero based on the assumption that energy storage benefits are not yet able to be monetized[23].

[21] Home Energy Solutions (HES) is a residential energy efficiency program operated by the Connecticut utilities and includes a wide variety of energy efficiency measures and activities beginning with an in-home energy assessment. Core measures include a blower door test before and after implementation of air and duct sealing. The assessment also includes lighting upgrades and identification of further and deeper energy savings opportunities in the home such as insulation, appliance and HVAC upgrades for which participants have access to incentives and financing. Though this assessment does not stipulate exactly which measures are installed, the analysis uses the average benefits and costs per participant, which represents a mix of basic and more advanced efficiency measures. RSIP participants are required to obtain a HES or equivalent Buildings Performance Institute (BPI) certified energy audit in order to receive the RSIP incentive.

[22] The energy storage portion of the bundle is assumed to be a leased Tesla PowerWall 7 kWh home energy storage system. Though this unit is somewhat more expensive than current lead acid based battery systems, the popularity of the product line and offerings by major vendors make it a reasonable choice for potential future residential scale energy storage products that may be of interest to typical Connecticut customers. To calculate the PACT and TRC, Cadmus assumed an 8% program administration cost (amounting to $400) in addition to the participant cost of the energy storage system.

[23] See report section “Cost-Effectiveness of Bundled Technologies” for more details.

Table 6. Cost-Effectiveness of Bundled Resources[24]

Program/Technology	Test	# Participants	Benefits/ Participant	Costs/ Participant	Net Benefits/ Participant	Ratio
RSIP 2015 Step 7	TRC	2,639	$55,050	$30,548	$24,502	1.80
	PACT	2,639	$17,525	$2,709	$14,816	6.47
	PCT	2,639	$48,093	$26,724	$21,370	1.80
EE 2016 Eversource – Home Energy Solutions (HES)	TRC	17,320	$3,597	$1,102	$2,495	3.26
	PACT	17,320	$990	$547	$443	1.81
	PCT	17,320	$1,933	$65	$1,868	29.75
RSIP 2015 Step 7 + EE 2016 Eversource HES	TRC	1	$58,647	$31,651	$26,996	1.85
	PACT	1	$18,514	$3,255	$15,259	5.69
	PCT	1	$50,026	$26,789	$23,238	1.87
Energy Storage	TRC	1	$0	$5,400	($5,400)	0.00
	PACT	1	$0	$400	($400)	0.00
	PCT	1	$0	$5,000	($5,000)	0.00
RSIP 2015 Step 7 + Storage	TRC	1	$55,050	$35,948	$19,102	1.53
	PACT	1	$17,525	$3,109	$14,416	5.64
	PCT	1	$48,093	$31,724	$16,370	1.52
RSIP 2015 Step 7 + EE 2016 Eversource HES + Storage	TRC	1	$58,647	$37,051	$21,596	1.58
	PACT	1	$18,514	$3,655	$14,859	5.06
	PCT	1	$50,026	$31,789	$18,238	1.57

The RSIP net benefits (approximately $24,500 per participant) are sufficient, on a per participant basis, to support the cost of a 7 kWh residential energy storage system, while still passing the TRC, PACT and PCT tests. More broadly, in the section of the report "Cost-Effectiveness of Bundled Technologies," we show that bundling solar PV, energy efficiency measures (using the utility-administered Home Energy Solutions Program as an example) and energy storage is cost-effective. The cost-effectiveness of mature technologies in the RSIP and HES programs can be leveraged to support newer technologies, in this case

[24] Although the PCT is not calculated in the EE CL&M plans, enough data were provided to estimate the PCT for the HES Program for the purposes of this example bundling calculation. The total customer costs and number of measures/participants for HES were taken from the 2016-2018 CL&M Plan, Table B2 – Eversource CT Electric – Resource Summary 2016. Benefits were estimated by multiplying the lifetime savings in MWh attributed to HES and multiplying by 19.23 cents per kWh, the Energy Information Administration (EIA) average residential price of electricity in CT for September 2015 (from the Electric Power Monthly Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2015 and 2014). This resulted in HES per participant benefits of $1933, and costs of $65, resulting in a highly favorable PCT of 29.75. The ratio could have been higher if the benefits estimate calculation included an escalator for the price of electricity and if the peak kW impact was included in the benefit estimate, but the simplified calculation already yielded highly favorable results that were sufficient to illustrate the benefit of bundling technologies. The per participant HES cost of $65 is lower than the expected $99 (the per participant contribution to the HES Program as typically advertised); this is because some of the costs for homes utilizing gas are allocated to the respective gas budget in the CL&M plan.

energy storage, that have not yet achieved commercial cost-effectiveness. This finding supports policies and programs that support comprehensive energy solutions for homeowners as well as grid modernization benefits.

The RSIP is not currently eligible to bid resources into the ISO-NE Forward Capacity Market (FCM). The Green Bank asked Cadmus to research potential eligibility for RSIP to bid into the ISO-NE FCM. Based on Cadmus' research, the current market rules for the Forward Capacity Auction process preclude the participation of small-scale resources such as distributed solar PV systems. The most immediate obstacle to participation is the 100 kW minimum output requirement, which is required on a site by site basis and far exceeds the available output of the individual project sizes found among residential PV systems[25]. See Appendix A for a copy of Cadmus' memo to the Green Bank providing a complete analysis of this topic.

[25] The average solar PV system size is 7.44 kW for the full RSIP dataset used in this study.

Overview

Cadmus, under contract to the Connecticut Green Bank (the Green Bank, or CGB), analyzed the Residential Solar Investment Program's (RSIP) cost-effectiveness using the following five cost-effectiveness tests applied to evaluation of conservation and load management programs, as described in the California Standard Practice Manual[26].

- Total Resource Cost Test (TRC)
- Program Administrator Cost Test (PACT)
- Participant Cost Test (PCT)
- Ratepayer Impact Measure Test (RIM)
- Societal cost test (SCT)

Cadmus applied the following five cost-effectiveness tests to each of the RSIP incentive types separately, the Expected Performance Based Buy-Down Program (EPBB) and the Performance Based Incentive Program (PBI), as well as for the RSIP overall. Additionally, Cadmus calculated the Green Bank (CGB) Objective Function (OF), a performance metric (that measures energy saved/generated per dollar invested) created by the Green Bank for program assessment, planning and reporting purposes. This section provides an explanation of RSIP program elements, the cost-effectiveness tests used in this study and the calculation of the Green Bank Objective Function. Additional details about study methodology are provided in the Methodology section of the Program Cost-Effectiveness section of this report.

Background on the Residential Solar Investment Program

In 2011, Connecticut's legislature passed Public Act 11-80, which created the Connecticut Green Bank pursuant to Connecticut General Statute (CGS) 16-245n and tasked it with creation of the Residential Solar Investment Program (RSIP) (CGS 16-245ff) which was to result in installation of 30 MW of new residential solar PV by 2022, funded by no more than one-third of the total annual surcharge collected from customers of electric services, and providing "incentives that decline over time and will foster the

[26] http://cpuc.ca.gov, or http://sustainca.org/content/california_standard_practice_manual_economic_analysis_demand_side_programs_and_projects, "California Standard Practice Manual. Economic Analysis of Demand-Side Programs and Projects." October 2001, first published in 1983. The 2001 manual includes solar PV as a load management technology in the category of "self generation": "Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid… Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines." Note that RSIP incentives are structured to encourage solar PV system sizing that will generate enough electricity to match a customer's electricity usage on an annual basis. Additional capacity beyond that needed to meet a customer's electricity usage is incentivized at a lower, second tier amount – see Methodology section for more details on RSIP incentive levels.

sustained, orderly development of a state-based solar industry." RSIP met the 30 MW target eight years ahead of schedule, in 2014. Governor's Bill No. 6838, "An Act Concerning the Encouragement of Local Economic Development and Access to Residential Renewable Energy," was signed into law July 2, 2015 by Governor Malloy, expanding the RSIP target from 30MW to 300MW by 2022 and establishing the Solar Home Renewable Energy Credit (SHREC) a new type of Class I REC which utilities are to purchase from the Green Bank through 15-year contracts as a funding source for RSIP (this bill updates CGS 16-245ff).[27]

The RSIP provides two types of incentives, the Expected Performance Based Buydown (EPBB) and a Performance Based Incentive (PBI). For the EPBB incentive type, the homeowner owns the PV system and the installer receives the incentive payment[28] from the Green Bank on behalf of the customer who has benefited from a buydown or reduction in the cost of the system. Participants also receive a 30% federal investment Tax Credit (ITC)[29]. The system cost, Green Bank incentives, and federal ITC are modeled as occurring during the first year of installation.

For PBI projects, a third-party system owner owns the PV system, and leases it (and its associated generation) to the homeowner, either for a monthly payment or an energy-based rate/charge (i.e., a power purchase agreement). Customers generally pay a reduced electricity rate for the electricity generated by the PV system as compared to the rate charged by the utility. The rate paid by the customer and other details are specified in a contract. Some of these contracts involve an initial down payment which in some cases allows the customer to pay a fixed rate for electricity generated. Some contracts provide for an escalating rate, such as when no down payment is made.

For PBI projects, the Green Bank pays incentives to third party system owners quarterly over a six year period based on actual electricity generation measured by revenue grade meters required by the Green Bank. The Federal Investment Tax Credit (ITC) can be claimed by third party system owners in the first year and is modeled as such. Third party system owners may also take advantage of MACRS.[30] As contract details between homeowners and installers are typically different from one installation to the

[27] Governor's Bill No. 6838: https://www.cga.ct.gov/2015/TOB/h/pdf/2015HB-06838-R00-HB.pdf, and CGS chapter 283, section 16-245ff: https://www.cga.ct.gov/current/pub/chap_283.htm.

[28] A history of RSIP incentives is provided in the Methodology section.

[29] The ITC had been set to expire at the end of 2016 but was extended at its current level of 30%; a 30% ITC was assumed for all projects in this study. For third party owned projects, the ITC will decline starting in 2020, decreasing to 10% in 2022 and future years (http://programs.dsireusa.org/system/program/detail/658). For homeowner owned projects, the ITC will decline in 2020 and 2021 and expires at the end of 2012 (http://programs.dsireusa.org/system/program/detail/1235).

[30] MACRS (Modified Accelerated Cost-Recovery System) is a Federal tax benefit that allows businesses to claim the depreciated value of solar assets as a tax deduction over a five year period. For more information, see http://programs.dsireusa.org/system/program/detail/676, and http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs.

next (hence offering limited access to this information), the PCT treats the third-party system owner and homeowner together as the "participant" for PBI projects.[31]

Overview of Cost-Effectiveness Tests

The below descriptions provide: (1) an overview of the five cost-effectiveness tests and (2) an explanation of the Green Bank Objective Function. Table 7, which follows these descriptions, presents a summary of the cost and benefit inputs used in the application of the five cost-effectiveness tests to RSIP.

For program assessment and planning purposes, note that in assessing the cost-effectiveness of the energy efficiency programs, Connecticut's investor owned utilities calculate the TRC, UCT/PACT, and a modified UCT/PACT which incorporates non-electric and non-resource benefits such as gas, oil, propane, and water savings. Note that jurisdictions nationwide may include different inputs for these tests – for example, the TRC, as calculated by the Connecticut utilities, includes non-embedded emissions reduction benefits.

Total Resource Cost Test

The Total Resource Cost Test (TRC) is based on the ratio of lifecycle benefits from energy and demand savings or renewables programs over lifecycle total incremental costs (regardless of who pays them). This test indicates whether an energy efficiency or renewables program is more cost-effective than supplying energy through traditional generation-based methods. The benefits are composed primarily of the reduction in current and future utility costs in the form of reduced fuel expenses and deferred capital investments in generation and transmission and distribution. As previously noted, Connecticut utilities include both embedded and non-embedded carbon dioxide emissions reduction benefits in the calculation of the TRC.[32] The TRC calculation as applied to RSIP also included both emissions reduction benefits.

Program Administrator Cost Test

The Program Administrator Cost Test (PACT) compares the value of energy efficiency or renewable energy benefits compared to the cost to the utility or the program administrator. The benefits are similar to those included in the TRC test, but the costs are narrowly defined to be those of the program administrator only.

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[31] Cadmus conducted a small test using data analyzed for steps 1 through 3 for which detailed third party owned lease and PPA rates had been previously collected; based on this data, calculating the PCT with just the homeowner as the participant, instead of the homeowner and third party owner as a group, would result in slightly lower but similar PCT scores. This is not surprising, as the third party system owner will take some of the benefit to make a profit, while still keeping the program in the financial interest of the homeowner.

[32] This study uses the Avoided Energy Supply Costs (AESC) 2015 Report estimate of $100/short ton which is considered to be a reasonable estimate of the total societal cost of carbon dioxide emissions. See the Methodology section of this report for more details.

Participant Cost Test

The Participant Cost Test (PCT) measures cost-effectiveness from the program participant's[33] perspective. The benefits estimated for the RSIP under this test are:

- Electric bill reduction (based on retail electricity rates)
- Federal tax incentives (the Federal investment tax credit as well as MACRS for PBI projects)
- RSIP incentives

As applied to RSIP, the costs are simply the installed cost of the PV system, also known as the incremental measure cost[34]. In this analysis, for the EPBB the participant was simply the homeowner who purchased solar, whereas for the PBI, the participant included the homeowner hosting the system as well as the third party developer. For EPBB, the participant costs assume a cash purchase and do not include potential customer financing costs.

Ratepayer Impact Measure Test

The Rate Payer Impact Test (RIM) measures the impact of energy efficiency or renewable energy on utility rates. The major benefit considered in the RIM test is the reduction of primary fuel consumption for electricity generation, while the costs include program administrator and program incentive costs (as in the PACT) and utility lost revenues (based on retail electricity rates) due to reduction in use of energy. The RIM test assumes that the cost of lost utility revenue is redistributed among all ratepayers. More often than not, any measure that reduces the utility's sale of electricity will fail to pass the RIM test, regardless of total resource or societal cost-effectiveness. Load shifting and demand reduction programs are more likely to pass the RIM test.

Societal Cost Test

The Societal Cost Test (SCT) expands on the TRC, taking the view of society at large, and allows for associated non-energy benefits and other environmental factors to be taken into account. In the analysis of RSIP, job creation and economic benefits, represented as increased disposable personal income[35] in the state of Connecticut, were included as a benefit for the SCT. Federal incentives

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[33] Note that, for purposes of this report, the terms "customer", "participant", "program participant", and "homeowner" may be used interchangeably to represent the host customer who owns the residence at which the PV system is installed and either owns, leases, or is an offtaker for the PV system. Note that, for PBI, the "program participant" is jointly the homeowner and the PV system installer, as the benefits are shared between these parties and cannot be readily segregated.

[34] Incremental measure cost is the term used in the energy efficiency setting for the cost of a more efficient technology such as an LED bulb instead of a baseline (incandescent) light bulb. With solar PV, the baseline "equipment" is no PV system, with a cost of zero, so the incremental cost is the total cost of the PV system.

[35] Disposable personal income is personal income less personal taxes. Estimates for disposable personal income were based on a study conducted for the Green Bank by the University of Connecticut, Connecticut Center for Economic Analysis (CCEA) : "Connecticut Green Bank's Residential Solar Investment Program: Economic Analysis of Existing Commitments and Future Scenarios," Peter Gunther (CCEA), Fred Carstensen (CCEA), and William Waite (Semnia, LLC), February 9, 2015.

(including the ITC), treated as a benefit in the TRC, were not included, as the SCT viewed these as a transfer payment from the federal government to participants.

Connecticut Green Bank Objective Function

The Green Bank uses the Objective Function (OF) as a program performance metric, calculated by dividing lifetime energy generation by program costs, including administrative and incentive payments.

The calculation of the CT Green Bank Objective Function is based on the following formula with input variables to the formula that are applicable to RSIP, including: (1) Energy generated or saved, (2) RSIP incentives, (3) RSIP program and administrative costs, and (4) Renewable energy certificate (REC) revenue. For the RSIP analyses, “credits enhancements” and “amount of financing” were not included in the Objective Function calculation, as these inputs are only applicable to Green Bank financing programs. These types of inputs were also not included in the RSIP benefit/cost ratio calculations.

Green Bank Objective Function Formula:

$$\frac{(Energy\ Generated\ or\ Saved) * (\%\ Realized)}{\begin{array}{c}Green\ Bank\ Incentives\ +\ Program\ and\ Administrative\ Cost + Credit\ Enhancements \\ +\ Amount\ of\ Financing - REC\ Revenue\end{array}}$$

For this evaluation, the variables that were included were (1) energy generated in kilowatt-hours, in the numerator, and (2) RSIP incentives and (3) RSIP Program and Administrative costs, in the denominator. REC revenues were not included in order to simplify the calculation, given the differences in applicable REC revenue streams across steps 1 through 7, as well as the minimal impact this would have on the results[36].

For energy generated, the realization rate was assumed to be 100%, to be conservative, though a previous RSIP evaluation conducted by Cadmus found RSIP steps 1 through 3 to have a 105% realization rate.[37] Solar PV system lifetime is assumed to be 25 years.[38] The electricity generation is calculated to include a 7% line loss factor, as onsite generation does not incur distribution losses. In order to simplify the analysis, Cadmus did not include performance degradation (typically 0.5% per year) or operations

[36] REC revenues numbers were not yet available for all steps and the amounts available thus far were not significant compared to the incentive costs. Thus, these revenues would not have made a significant impact on the results based on the data available thus far (though it would have made the CGB OF results slightly higher).

[37] “Residential Solar Investment Program Evaluation,” Shawn Shaw, Danielle Kolp, Mary Knipe, Ryan Fahey, Kathleen Higgins, The Cadmus Group, January 28, 2015. The realization rate of 105% calculated in the earlier Cadmus evaluation of RSIP showed 5% more electricity generation measured by revenue grade meters than was calculated by the PowerClerk incentive application processing system, which estimates generation for each project based on its specific equipment and site and design characteristics including azimuth, tilt and shading. http://www.ctgreenbank.com/wp-content/uploads/2016/02/RSIP_Evaluation_I_Final_Report_and_cvr_ltr.pdf

[38] NREL provides a range of 25 to 40 years for the useful life of a photovoltaic system, http://www.nrel.gov/analysis/tech_footprint.html.

and maintenance (O&M) costs in this analysis. The impact of these values is expected to be minimal when compared to the other costs and benefits included in the analysis.

Table 7, below, summarizes the benefits and costs included in the five cost-effectiveness tests, as applied to RSIP, and the Objective Function calculation for RSIP.

The calculations of the five cost-effectiveness tests and the Green Bank Objective function for RSIP do not include the benefits of renewable energy credit (REC) revenues, losses due to system degradation, or O&M costs, as explained in the above description of the Green Bank Objective Function.

Table 7. Cost-Effectiveness Benefits and Costs

	TRC	PACT	PCT	RIM	SCT	CGB OF
Avoided Energy Supply	Benefit	Benefit		Benefit	Benefit	
Non-Embedded Avoided Emissions	Benefit				Benefit	
Avoided Capacity Supply	Benefit	Benefit		Benefit	Benefit	
Participant Bill Savings			Benefit	Cost		Benefit
Program Administration Costs	Cost	Cost		Cost	Cost	Cost
Program Incentives		Cost	Benefit	Cost		Cost
Participant Incremental Measure Costs[39]	Cost		Cost		Cost	
Federal Investment Tax Credit (ITC)[40]	Benefit		Benefit			
Job Creation Benefits					Benefit	
MACRS Benefits (PBI Only)[41]	Benefit		Benefit			

[39] Incremental measure cost is the term used in the energy efficiency setting for the cost of a more efficient technology such as an LED bulb instead of a baseline (incandescent) light bulb. With solar PV, the baseline "equipment" is no PV system, with a cost of zero, so the incremental cost is the total cost of the PV system.

[40] Treatment of tax credits varies among jurisdictions and can be modeled either as a transfer payment with neutral impact on cost effectiveness, or as a reduction in costs or as an increase in benefits. For the RSIP, the ITC and MACRS are treated as an increase in benefits for the TRC and PCT, and as transfer payments on the SCT. The ITC is treated as a benefit for the TRC as it is incorporated as an incentive (from outside the program) that reduces the cost of PV as a resource in comparison with other sources.

[41] MACRS (Modified Accelerated Cost Recovery System) is a federal tax benefit that allows businesses to claim the depreciated value of solar assets as a tax deduction over a five year period. For more information: http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs.

Program Cost-Effectiveness

Methodology

This section summarizes the assumptions made and methods employed in making the cost-effectiveness calculations noted previously.

Cost Effectiveness Tests

Cadmus compiled the costs and benefits for each of the cost effectiveness tests discussed previously and calculated the relevant ratios using the parameters noted below.

Total Resource Cost Test

Benefits included:

- Avoided energy and capacity costs associated with offset electricity generation
- Federal tax incentives (ITC and, for PBI, MACRS)
- Non-embedded avoided emissions

Costs included:

- Program administrator costs
- PV system total installed cost (not including RSIP incentives)

Program Administrator Cost Test

Benefits included:

- Avoided energy and capacity costs

Costs included:

- RSIP incentives
- Program administration cost

Participant Cost Test

Benefits included:

- Electricity bill reduction
- Federal tax incentives (ITC and, for PBI, MACRS)
- RSIP incentives

Costs included:

- PV system total installed cost

Ratepayer Impact Measure Test

Benefits included:

- Avoided energy and capacity costs

Costs included:

- RSIP incentives
- Participant electricity bill reduction
- Program administration costs

Societal Cost Test

Benefits included:

- Avoided energy and capacity costs
- Non-embedded avoided emissions
- Job creation benefits

Costs included:

- Program administration costs
- PV system total installed cost

Avoided Energy and Capacity Costs

Assumptions for avoided energy and avoided capacity costs for year 2016 and future years were provided by Eversource from a model based on the Avoided Energy Supply Costs in New England: 2015 Report (AESC 2015 Report).[42] Assumptions for avoided energy and avoided capacity costs for years 2012-2015 were obtained from the AESC 2011 report.[43]

Benefits counted through the TRC, PACT, RIM, and SCT include the following:

- The full value of time and seasonally differentiated[44] avoided energy generation costs. Avoided energy costs also included Demand Reduction Induced Price Effects (DRIPE).[45]

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[42] Avoided Energy Supply Costs in New England: 2015 Report, Hornby et al, Revised April 3, 2015. (AESC 2015 Report). http://www.ct.gov/deep/lib/deep/energy/aescinnewengland2015.pdf. Avoided energy and capacity costs associated with this model and provided by Eversource included the most updated 2016 cost numbers.

[43] Avoided Energy Supply Costs in New England: 2011 Report, Appendix B, Avoided Cost of Electricity Results, CT Statewide, Synapse Energy Economics, Inc., Hornby et al, Revised August 11, 2011.

[44] During different hours of the year, different fuel mixes are used to meet the hourly energy usage, causing differences in avoided generation costs. Also during certain peak hours of the year, there are added capacity cost values due to the delay in need for added capacity on the generation or on the transmission and distribution side.

[45] DRIPE effects included in this study were Intrastate, Rest-of-Pool, and Electric Own Fuel & Cross Fuel DRIPE. "DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of

- Avoided capacity costs associated with electricity generation, transmission and distribution.
- Non-embedded emissions reductions.

Table 8 shows the seasonal categories for which avoided energy costs were provided in the AESC 2015 Report and the percentage of kWh for the RSIP portfolio assigned to each category. Though there is more available solar irradiance per day in the summer period, it is important to note that the winter period is significantly longer. The summer period includes June through September and the winter period includes all remaining months. Peak period is 7:00 am until 11:00 pm non-holiday weekdays.[46]

Table 8. Distribution of RSIP kWh across Seasonal Categories

	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Percentage of RSIP kWh	42%	18%	28%	12%

Table 99 shows avoided energy cost for 2012[47] and the average escalator.

Table 9. Summary of Avoided Energy Costs

	2012 Value ($/kWh)	Average Yearly Escalator
Avoided Energy Cost[48]	$0.149	2.23%

Table 10 shows the average non-embedded avoided emissions cost, which is included for the TRC and SCT (as a benefit). This follows the methodology of the Eversource model which includes both embedded and non-embedded avoided emissions costs[49] in the TRC test. The PACT, PCT and RIM include only the embedded emissions.

Table 10. Summary of Non Embedded Avoided Emissions Costs

2012 Non Embedded Avoided Emissions ($/kWh)	Average Yearly Escalator
$0.044	0.72%

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efficiency and/or demand response programs [in this case from installed solar photovoltaic capacity].” AESC 2015 Report, page 1-16, http://www.ct.gov/deep/lib/deep/energy/aescinnewengland2015.pdf.

[46] ISO-NE Glossary: http://www.iso-ne.com/participate/support/glossary-acronyms.

[47] Assumptions for avoided energy and avoided capacity costs for years 2012-2015 were obtained from the Avoided Energy Supply Costs in New England: 2011 Report, Appendix B, Avoided Cost of Electricity Results, CT Statewide, Synapse Energy Economics, Inc., Hornby et al, Revised August 11, 2011.

[48] Note that these costs include DRIPE.

[49] Embedded avoided emissions costs are those already accounted for by existing policies and regulations, and are incorporated into utility avoided costs. Non-embedded emissions costs are those not currently reflected in market prices. This study uses the AESC 2015 Report estimate of $100/short ton which is considered to be a reasonable estimate of the total societal cost of carbon dioxide emissions (AESC 2015 Report, page 4-29). The non-embedded cost comes out to between 4-5 cents/kWh after subtracting out the embedded cost, a much smaller portion of the total $100/short ton estimated cost. The embedded cost of CO_2 is $6.28/short ton in 2015, estimated to rise to $33.94 by 2030 (AESC 2015 Report, page 4-3, Exhibit 4-1).

Table 11 shows avoided capacity costs used in the analysis.

Table 11. Summary of Avoided Capacity Costs

	2012 Value ($/kW)	Average Yearly Escalator
Avoided Generation Cost	$38.24	13.15%
Avoided T&D Costs	$35.18	1.90%

Peak Period Output of Residential PV Systems

As part of this analysis, Cadmus created an annual hourly profile of RSIP PV system electricity generation, as described below. Using this generation profile, Cadmus created capacity savings values by taking the average generation on weekdays between 1 pm and 5 pm in June, July, and August, and multiplying these by the avoided capacity costs to calculate the capacity benefit. For this peak period, we calculated AC capacity savings by multiplying the nameplate DC capacity by 0.33. For example, a PV system with a nameplate DC capacity of 10 kW would offset an average capacity of 3.3 kW-AC during the defined peak period[50]. A typical PV system installed through the RSIP, at an average nameplate capacity of approximately 7kW, offsets an average of 2.1kW-AC during the defined peak period.

Cadmus created an aggregate hourly generation profile for all RSIP projects (including steps 1 through 7) by looking at the following system characteristics of both PBI and EPBB incentive types as recorded in the Green Bank's PowerClerk database:

- Array tilt
- Array azimuth
- System capacity (nameplate kW_{DC})
- Solar access/shading

By conducting a bin analysis on these key characteristics, Cadmus created six PV profiles that represented 90% and 84% of EPBB and PBI projects in the dataset, respectively, shown in Table 12. Cadmus then ran six independent hourly models in PVWATTS based on these profiles. Using these hourly electricity generation profiles (analogous to load shapes for energy efficiency measures) of the six hourly generation models from PVWatts, Cadmus created a composite, average hourly generation profile that reflects the weighted mix of system characteristics. As previously stated, Cadmus reported capacity savings values by taking the average generation on weekdays between 1 pm and 5 pm in June, July, and August, and multiplying these by the avoided capacity costs.

[50] Approximately 11% of electricity generated by RSIP-supported PV systems was generated during the defined peak periods.

Table 12. PV System Characteristics Used in Hourly Modeling

Modeling Parameters														
Azimuth			Tilt		EPBB		PBI		PVWatts Inputs			% of Projects Represented	
From	To	Description	From	To	# of Systems	Percentage	# of Systems	Percentage	Azimuth	Tilt	Losses[51]	EPBB	PBI
-30	30	South	0	20	359	9%	513	10%	0	10	20%	9%	10%
-30	30	South	20	40	2114	55%	2024	39%	0	30	20%	55%	39%
30	90	Southwest	0	20	144	4%	315	6%	60	10	20%	4%	6%
30	90	Southwest	20	40	528	14%	1087	21%	60	30	20%	14%	21%
-90	-30	Southeast	0	20	144	4%	260	5%	-60	10	20%	4%	5%
-90	-30	Southeast	20	40	524	14%	981	19%	-60	30	20%	14%	19%
Total					**3813**		**5180**		**Projects Covered**			**90%**	**84%**

Retail Electricity Rates

For the cost tests requiring the use of retail electricity rates (PCT, RIM), this study used the U.S. DOE Energy Information Association (EIA) Electric Power Monthly average retail price to ultimate consumers, which for 2012 was $0.17 per kWh. The study assumed a 2.99% annual escalation rate.

Incentives

RSIP progressed through seven incentive steps during the period analyzed, with each step representing an incentive reduction. Table 13 shows each step, its start year, start date, and incentive details.

[51] These losses include factors such as DC to AC conversion and wiring losses.

Table 13. Program Step Year, Start Date, Incentive Details[52]

Program Step	Year	Start Date	Maximum Size (kW-PTC)	Incentive for first 5 kW-PTC	Incentive for second 5 kW-PTC	Incentive for > 10 kW-PTC up to 20 kW-PTC
EPBB Step 1	2012	3/2/2012	10 kW	$2.45/W	$1.25/W	
EPBB Step 2	2012	5/18/2012	10 kW	$2.275/W	$1.075/W	
EPBB Step 3	2013	1/4/2013	10 kW	$1.750/W	$0.55/W	
EPBB Step 4	2014	1/6/2014	10 kW	$1.250/W	$0.75/W	
EPBB Step 5	2014	9/1/2014	20 kW	$0.80/W		$0.40/W
EPBB Step 6	2015	1/1/2015	20 kW	$0.675/W		$0.40/W
EPBB Step 7[53]	2015	4/11/2015	20 kW	$0.54/W		$0.40/W
PBI Step 1	2012	3/2/2012	10 kW	$0.30/kWh		
PBI Step 2	2012	5/18/2012	10 kW	$0.30/kWh		
PBI Step 3	2013	4/1/2013	10 kW	$0.225/kWh		
PBI Step 4	2014	1/6/2014	10 kW	$0.18/kWh		
PBI Step 5	2014	9/1/2014	20 kW	$0.125/kWh		$0.060/kWh
PBI Step 6	2015	1/1/2015	20 kW	$0.08/kWh		$0.060/kWh
PBI Step 7	2015	4/11/2015	20 kW	$0.064/kWh		$0.060/kWh

[52] RSIP incentives are based on a solar PV system's PTC rating, which differs from the Standard Test Conditions (STC) or DC rating used for module "nameplate" values. The PTC rating, which is generally lower than the STC rating, is recognized to be a more realistic measure of PV output because the test conditions better reflect real-world conditions. The PTC rating is used by programs in California, Connecticut, and elsewhere as the basis of incentive calculations. PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA or Photovoltaics for Utility Systems Applications project. PTC are defined as 1,000 watts per square meter solar irradiance, 20 degrees Celsius *air* temperature, and wind speed of 1 meter per second at 10 meters above ground level. STC are based on 25 degrees Celsius *cell* temperature. The PTC rating differs in that its test conditions of ambient temperature and wind speed will result in a PV cell temperature of about 50 degrees Celsius, instead of the 25 degrees Celsius assumed for STC. Consequently, for crystalline silicon PV systems with a power degradation due to temperature of -0.5% per degree Celsius, the PV module PTC power rating is generally about 88% of the PV module STC or nameplate rating.

[53] Step 7 end date was August 7, 2015, and step 8 start date was August 8, 2015. PowerClerk data was extracted on August 12, 2015 for this study and included 21.4 MW of step 7 projects in approved or later project statuses. Not all step 7 projects had been approved by August 12 when the data was extracted for this study. As of January 11, 2016, step 7 capacity was 21.3 MW, so projects that had not yet been approved as of August 12 ended up roughly balancing out with projects that had been approved but later cancelled.

The Green Bank provided Cadmus with data on actual system costs and RSIP incentives, estimated federal incentives, and estimated annual generation (calculated by PowerClerk[54] for each project and incorporating factors such as system size, azimuth, tilt, and shading). See Table 14, as well as Table 15, which provides project cost and incentive data on a per Watt basis.

Table 14. Solar PV Capacity, Total Solar PV Project Costs, Incentives, and Estimated Generation by Incentive Type and Program Step

Program Step	Solar PV Capacity (kW)	Total Solar PV Project Cost	RSIP Incentive	Estimated Federal Investment Tax Credit	Estimated Annual Generation (kWh)	Estimated Annual Generation (kWh/kW)[55]	System Life
EPBB Steps 1 & 2	5,419	$24,600,069	$8,628,939	$5,323,710	6,387,113	1179	25
EPBB Step 3	9,290	$38,039,591	$10,606,806	$9,144,262	10,839,917	1167	25
EPBB Step 4	8,471	$34,096,316	$7,382,147	$8,904,723	9,854,120	1163	25
EPBB Step 5	3,612	$15,207,396	$2,394,340	$4,271,019	4,241,127	1174	25
EPBB Step 6	4,381	$18,446,776	$2,443,077	$5,334,566	5,056,380	1154	25
EPBB Step 7	1,997	$8,569,145	$885,861	$2,561,095	2,243,292	1123	25
EPBB Total	**33,171**	**$138,959,293**	**$32,341,170**	**$35,539,374**	**38,621,949**	**1164**	25
PBI Steps 1 & 2	1,961	$9,632,004	$3,623,842	$2,002,721	2,038,522	1040	25
PBI Step 3	4,018	$18,707,273	$5,750,652	$4,318,873	4,313,225	1073	25
PBI Step 4	11,990	$55,545,603	$13,704,413	$13,947,063	12,856,183	1072	25
PBI Step 5	11,168	$50,828,635	$8,600,900	$14,075,912	11,781,319	1055	25
PBI Step 6	9,614	$43,865,470	$4,710,451	$13,051,673	10,035,135	1044	25
PBI Step 7	19,417	$85,298,075	$7,640,064	$25,886,004	20,188,179	1040	25
PBI Total	**58,169**	**$263,877,061**	**$44,030,323**	**$73,282,246**	**61,212,563**	1052	**25**

[54] PowerClerk is a program tracking and administrative software platform used for RSIP incentive applications.
[55] On average, PBI projects have a lower kWh/kW than EPBB projects due to system characteristics such as the solar PV panels used and design characteristics such as azimuth, tilt and shading.

Table 15. Solar PV Capacity, Total Solar PV Project Costs, and Incentives, by Incentive Type and Program Step (on a per Watt basis)

Program Step	Solar PV Capacity (kW)	Total Solar PV Project Cost ($/W)	RSIP Incentive ($/W)	Estimated Federal Investment Tax Credit ($/W)	RSIP incentive as % of Project Cost	Federal ITC as % of Project Cost	RSIP Incentive plus ITC as % of Project Cost
EPBB Steps 1 & 2	5,419	$4.54	$1.59	$0.98	35%	22%	57%
EPBB Step 3	9,290	$4.09	$1.14	$0.98	28%	24%	52%
EPBB Step 4	8,471	$4.03	$0.87	$1.05	22%	26%	48%
EPBB Step 5	3,612	$4.21	$0.66	$1.18	16%	28%	44%
EPBB Step 6	4,381	$4.21	$0.56	$1.22	13%	29%	42%
EPBB Step 7	1,997	$4.29	$0.44	$1.28	10%	30%	40%
EPBB Total	**33,171**	**$4.19**	**$0.97**	**$1.07**	**23%**	**26%**	**49%**
PBI Steps 1 & 2	1,961	$4.91	$1.85	$1.02	38%	21%	58%
PBI Step 3	4,018	$4.66	$1.43	$1.07	31%	23%	54%
PBI Step 4	11,990	$4.63	$1.14	$1.16	25%	25%	50%
PBI Step 5	11,168	$4.55	$0.77	$1.26	17%	28%	45%
PBI Step 6	9,614	$4.56	$0.49	$1.36	11%	30%	41%
PBI Step 7	19,417	$4.39	$0.39	$1.33	9%	30%	39%
PBI Total	**58,169**	**$4.54**	**$0.76**	**$1.26**	**17%**	**28%**	**44%**

The PBI pays out RSIP incentives over six years to third party owners for each installation. One-sixth of the PBI incentive values shown in Table 14 were apportioned to the first year of each given step, with another one-sixth for each of the five years thereafter.

For the PBI incentive type, third party system owners can also take advantage of accelerated depreciation under the MACRS program, thus the model included these additional federal tax benefits. System owners could claim depreciation on 85% of a project's total cost as a tax benefit over the six-years following installation. Table 16 shows the percentage of the 85% of total costs that can be claimed by year after installation. These benefits significantly affect the TRC and PCT. The analysis used a 30% tax rate assumption for third party system owners.

Table 16. PBI Depreciation Percent by Year

Year	Percent of Depreciation Claimed
1	20.00%
2	32.00%
3	19.20%
4	11.52%
5	11.52%
6	5.76%

Program Administrative Costs

Table 17 shows administrative costs associated with each step of the PBI and EPBB incentive types. Due to the PBI program's nature[56], Cadmus modeled 80% of a given step's costs occurring in the first year, with the remaining 20% occurring equally over the next five years. For EPBB, all administrative costs were assigned to the step's first year.

Table 17. Administrative Costs by Program Step

Program Step	Administrative Costs
EPBB Steps 1 & 2	$464,207
EPBB Step 3	$707,139
EPBB Step 4	$351,374
EPBB Step 5	$152,252
EPBB Step 6	$165,147
EPBB Step 7	$79,907
EPBB Total	**$1,920,026**
PBI Steps 1 & 2	$164,957
PBI Step 3	$297,529
PBI Step 4	$502,942
PBI Step 5	$451,068
PBI Step 6	$336,031
PBI Step 7	$742,112
PBI Total	**$2,494,639**

Discounting Rates and Reporting Basis

For purposes of this analysis, Cadmus has converted all costs and benefits into 2012 dollars. This date coincides with the start of the RSIP and its use as a consistent basis allows a more straightforward comparison of benefits and costs across incentive steps, while eliminating discount rates as a possible obfuscating factor when comparing the results from individual steps.

The discount rate specified in the 2015 Annual Update to the 2013-2015 Electric and Natural Gas Conservation and Load Management (CL&M) Plan was applied to the TRC, PACT, and RIM tests.[57] The SCT rate used a 10-year Treasury bill rate to discount future benefits. The PCT used a 10% discount rate, which Cadmus has used on numerous similar cost-effectiveness analyses. Table 18 shows the discount rate applied to each benefit-cost test.

[56] Payment processing occurs for five additional years after the initial administrative work completed by the Green Bank for each project.

[57] 2015 Annual Update of the 2013-2015 Electric and Natural Gas Conservation and Load Management Plan, Chapter Six: Benefit/Cost Analysis, http://www.energizect.com/about/eeboard/plans.

Table 18. Nominal Discount Rates

Benefit-Cost Test	Discount Rate
TRC	5.50%
SCT	1.99%
PACT	5.50%
RIM	5.50%
PCT	10.00%

Program Attribution

For RSIP, Cadmus assumed a net to gross ratio[58] of one. This was a simplifying assumption based on net to gross (NTG) ratios for solar PV programs generally being close to 100%, based on experience with solar incentive programs in other jurisdictions, a prior RSIP evaluation conducted by Cadmus, and Cadmus' general experience and understanding of the solar PV industry:

- In impact evaluations Cadmus has completed in New York, Wisconsin, and other states, the portion of incentive recipients who would have installed a PV system without the incentive (known as free ridership) has been approximately balanced by the tendency of incentive recipients to take additional energy savings/conservation measures as a result of their participation in the incentive program (spillover). For example, the NYSERDA Customer Sited Tier solar PV projects[59] had a NTG ratio of 93.4% for residential projects.
- Federal incentives have been available in jurisdictions that do not offer RSIP-like incentives or marketing and outreach programs for solar PV (e.g., municipal utility service territories). Anecdotally, these territories have far less PV development than observed under the RSIP.
- In the RSIP evaluation conducted previously[60], Cadmus found through survey questions posed to RSIP participants that 88% of EPBB and 82% of PBI customers, respectively, would not have installed PV systems without the RSIP incentive and 30%-45% of customers also adopted additional energy efficiency measures[61] that provide savings beyond the direct generation of the PV systems.

[58] The net to gross ratio represents the ratio of savings attributable to the program, That is, net savings are gross savings minus those that would have happened in the absence of the program.

[59] http://www.nyserda.ny.gov/About/Publications/Program-Planning-Status-and-Evaluation-Reports/Evaluation-Contractor-Reports/2013-Reports, NYSERDA Renewable Portfolio Standard Customer-Sited Tier Impact Evaluation Report: Solar Electric (PV) and On-Site Wind Programs, see pages 2-25 through 2-34 for results and discussion on net to gross ratio.

[60] "Residential Solar Investment Program Evaluation," Shawn Shaw, Danielle Kolp, Mary Knipe, Ryan Fahey, Kathleen Higgins, The Cadmus Group, January 28, 2015. http://www.ctgreenbank.com/wp-content/uploads/2016/02/RSIP_Evaluation_I_Final_Report_and_cvr_ltr.pdf

[61] RSIP participants are required to obtain a Home Energy Solutions (HES) or equivalent Buildings Performance Institute (BPI) certified energy audit in order to receive the RSIP incentive. Most audits are performed through the HES Program which currently buys down the cost of the energy audit to $99. HES is a residential energy efficiency program operated by the Connecticut utilities and includes a wide variety of energy efficiency measures and activities beginning with an in-home energy assessment. Core measures include a blower door test before and

- Even with incentives, PV systems are large purchases for most customers and the incentives are generally a key driver. In addition to incentives, RSIP provides marketing and educational support for the industry, qualification of contractors and third party system owners, and inspection of solar PV systems.

Nevertheless, a rigorous analysis of attribution for the RSIP was outside the scope of this study. Though the authors believe the NTG assumptions are valid for this study, a more rigorous analysis of attribution could be conducted for the RSIP to examine the impact of other drivers such as financing, marketing, outreach and educational efforts, federal tax incentives (ITC, MACRS)[62], net metering, the steady decrease in system prices, high electricity prices, and improvement in the economy in recent years. Going forward, RSIP incentives will continue to decrease, and this will need to be taken into consideration with respect to program attribution.[63] Lastly, as the solar PV market transitions from dependence on RSIP incentives to sustaining itself without these incentives, RSIP will have met its mandate to: "provide incentives that decline over time and will foster the sustained, orderly development of a state-based solar industry."

Potential Forward Capacity Market Revenues

In order to assess the possibility of an additional revenue stream for the RSIP, Cadmus examined the current market rules and procedures related to the ISO-NE Forward Capacity Market (FCM) to determine if RSIP generation resources could be bid into the FCM, either individually or in aggregate. To research this issue, we conducted a literature review and several informal interviews with ISO-NE staff members. The results of this review are discussed in the Results section, with full findings provided in Appendix A.

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after implementation of air and duct sealing. The assessment also includes lighting upgrades and identification of further and deeper energy savings opportunities in the home such as insulation, appliance and HVAC upgrades for which participants have access to incentives and financing.

[62] Federal tax incentives for solar PV are significant. The federal investment tax credit (ITC) is currently 30% of the cost of a solar PV system, while third party solar PV system owners benefit from accelerated depreciation (MACRS) as well. The federal tax incentives for energy efficiency are much lower. Certain energy efficiency projects qualify for a 10% federal tax credit but with a maximum credit of $500 or lower depending on the measure. Federal incentives are included in the cost-effectiveness calculations for RSIP as a benefit for the TRC and PCT tests. They are not included in the cost-effectiveness calculations for the Connecticut energy efficiency programs. Tax credits can be modeled either as a transfer payment with neutral impact on cost effectiveness, or as a reduction in costs or as an increase in benefits.

[63] The question is that as incentives decrease, will the program play as large a role in a customer's decision to adopt solar PV. On the other hand, in measuring program attribution, programs may have market transformation impacts that persist into the future, i.e., that "today's free-riders may have been caused by yesterday's market transformation" as stated in the report "All these Years Measuring Free Ridership and Now We Measure a Portion of These as Caused by Market Transformation." Lori Megdal, Ph.D., Megdal & Associates, Steve Pertusiello, Consolidated Edison Company of New York, Bonnie Jacobson, Energy Access, 1996, http://www.anevaluation.com/pubs/aesp_96m.pdf.

Results

In this section, we summarize key findings from the cost-effectiveness analysis, as well as ancillary research related to combining RSIP with other types of resources, such as energy storage and energy efficiency, in a bundled configuration. This section also presents a summary of findings related to the eligibility of the RSIP to participate in the FCM process.

Cost-Effectiveness Findings

We have assessed the cost-effectiveness of the RSIP, including both incentive types and as the overall program. We first present the EPBB and PBI results, followed by results for RSIP overall and the Green Bank Objective Function calculations for RSIP.

EPBB

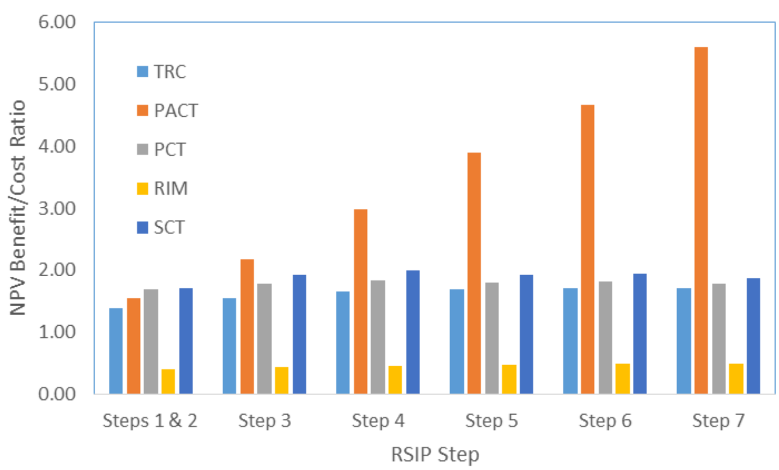
Overall, the EPBB incentive type passes all cost-effectiveness tests, except the RIM test, which most programs, including most energy efficiency programs, do not pass[64]. Cadmus examined the EPBB's cost-effectiveness as a whole (see Table 19) and for each individual step (Figure 2 and Table 20).

Table 69. EPBB Cost-Effectiveness for RSIP Steps 1-7 Combined

	TRC	PACT	PCT	RIM	SCT
NPV Benefits	$205,945,832	$82,125,323	$213,907,209	$82,125,323	$259,219,802
NPV Costs	$129,756,377	$32,097,118	$120,225,846	$182,694,195	$136,633,821
NPV Net Benefits	$76,189,455	$50,028,206	$93,681,363	-$100,568,872	$122,585,981
B/C Ratio	1.59	2.56	1.78	0.45	1.90

The EPBB's cost-effectiveness trends over time reflect a policy of reducing the amount of Green Bank resources spent on incentives, while continuing to support market growth through marketing, outreach, education and financing. From a participant perspective, although RSIP incentives decreased from steps 1 through 7, **Error! Reference source not found.** and Table 20 show that

Figure 2. EPBB Benefit/Cost Ratio Results



64 The RIM test, as noted previously, accounts only for the lost utility revenue and assumes that the cost is therefore redistributed among all ratepayers. More often than not, any measure that reduces the utility's sale of electricity will fail to pass the RIM test, regardless of societal or total resource cost-effectiveness. Load shifting and demand reduction programs are more likely to pass the RIM test.

the PCT remained relatively constant across all seven steps, reflecting relatively flat customer economics. Over the EPBB's life, the PACT has increased from 1.55 in Steps 1 & 2 to 5.60 in Step 7.

Table 20. EPBB Cost-Effectiveness by Step

Steps 1 & 2	TRC	PACT	PCT	RIM	SCT
NPV Benefits	$34,743,121	$14,120,229	$41,472,738	$14,120,229	$42,806,790
NPV Costs	$25,064,277	$9,093,146	$24,600,069	$34,654,168	$25,064,277
NPV Net Benefits	$9,678,844	$5,027,083	$16,872,669	-$20,533,939	$17,742,514
B/C Ratio	1.39	1.55	1.69	0.41	1.71
Step 3	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$56,913,295	$23,371,897	$61,671,069	$23,371,897	$72,715,401
NPV Costs	$36,726,759	$10,724,119	$34,581,446	$53,386,070	$37,986,991
NPV Net Benefits	$20,186,536	$12,647,778	$27,089,622	-$30,014,173	$34,728,410
B/C Ratio	1.55	2.18	1.78	0.44	1.91
Step 4	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$51,268,841	$20,728,638	$51,536,448	$20,728,638	$66,031,269
NPV Costs	$30,949,610	$6,948,201	$28,178,773	$45,141,707	$33,110,044
NPV Net Benefits	$20,319,231	$13,780,437	$23,357,675	-$24,413,069	$32,921,225
B/C Ratio	1.66	2.98	1.83	0.46	1.99
Step 5	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$23,247,585	$8,921,424	$22,621,034	$8,921,424	$28,328,044
NPV Costs	$13,799,912	$2,287,991	$12,568,096	$18,726,142	$14,763,214
NPV Net Benefits	$9,447,673	$6,633,433	$10,052,939	-$9,804,717	$13,564,831
B/C Ratio	1.68	3.90	1.80	0.48	1.92
Step 6	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$27,206,189	$10,378,607	$25,155,976	$10,378,607	$33,915,965
NPV Costs	$15,850,168	$2,221,199	$13,859,336	$21,438,003	$17,538,431
NPV Net Benefits	$11,356,021	$8,157,408	$11,296,639	-$11,059,396	$16,377,534
B/C Ratio	1.72	4.67	1.82	0.48	1.93
Step 7	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$12,566,801	$4,604,528	$11,449,944	$4,604,528	$15,188,290
NPV Costs	$7,365,651	$822,461	$6,438,125	$9,348,106	$8,150,195
NPV Net Benefits	$5,201,151	$3,782,067	$5,011,819	-$4,743,578	$7,038,095
B/C Ratio	1.71	5.60	1.78	0.49	1.86

In addition to these cost-effectiveness test results, Cadmus calculated the Green Bank Objective Function value of 32.2 kWh/$ for EPBB overall, and values for EPBB steps 1-7, with a steady increase over progressive steps consistent with improvement in the PACT scores.

Table 21. Objective Function Results by Step for EPBB

	Lifetime kWh	Program Administration Costs	Objective Function (kWh/$)
Steps 1 & 2	170,855,273	$9,093,146	18.79
Step 3	289,967,780	$10,724,119	27.04
Step 4	263,597,710	$6,948,201	37.94
Step 5	113,450,147	$2,287,991	49.59
Step 6	135,258,165	$2,221,199	60.89
Step 7	60,008,061	$822,461	72.96
Overall	**1,033,137,136**	**$32,097,118**	**32.19**

PBI

Like the EPBB, the PBI incentive type passed all cost-effectiveness tests except the RIM test which most programs including energy efficiency programs do not pass[65]. Compared to EPBB, PBI generally used the Green Bank's resources more cost-effectively (i.e., had a higher PACT result), while maintaining similar results for participant cost-effectiveness. The PBI performed better (on all tests except the SCT) because third party owned systems can take advantage of accelerated depreciation under the MACRS program, which is not available to direct ownership PV customers. Notably, the EPBB proved initially more cost-effective for the PACT, but the PBI surpassed it in Step 6 of the program. Any benefits that accrue due to depreciation are not reflected in the SCT as they are treated as transfer payments.

Table 22. PBI Cost-Effectiveness for RSIP Steps 1-7 Combined

	TRC	PACT	PCT	RIM	SCT
NPV Benefits	$413,048,730	$128,285,100	$382,607,179	$128,285,100	$426,242,221
NPV Costs	$235,081,510	$36,960,574	$211,593,693	$272,450,141	$254,345,891
NPV Net Benefits	$177,967,220	$91,324,525	$171,013,486	-$144,165,042	$171,896,330
B/C Ratio	1.76	3.47	1.81	0.47	1.68

As with the EPBB, the effectiveness of Green Bank funds disbursed through the PBI, as reflected by the PACT, increased over the program's life. The PACT for the PBI grew from 1.35 in Step 1 to 6.58 by Step 7, amounting to nearly a five-fold increase in leverage of the Green Bank's investment, while generally maintaining cost-effectiveness for participants.

In Step 7, the Green Bank reduced participant cost-effectiveness slightly, coinciding with a large increase in the PACT ratio. Despite Step 7's relatively low incentive, Step 7 was fully subscribed in less than four months, with over 2,600 projects funded.

[65] The RIM test, as noted previously, accounts for lost utility revenue and assumes that the cost is redistributed among all ratepayers. More often than not, any measure that reduces the utility's sale of electricity will fail to pass the RIM test, regardless of societal or total resource cost-effectiveness. Load shifting and demand reduction programs are more likely to pass the RIM test.

Figure 3. PBI Benefit/Cost Ratio Summary

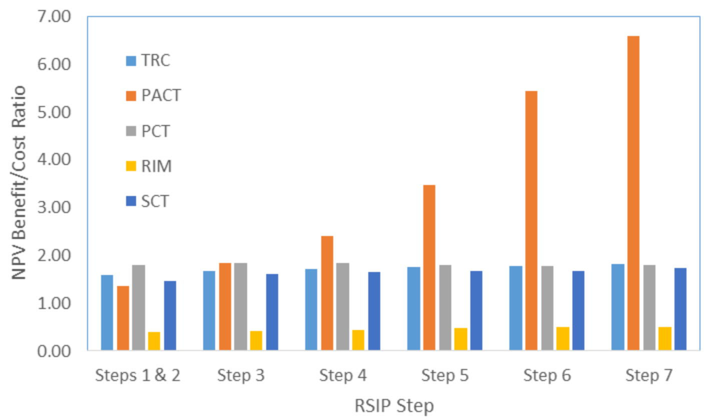


Table 23. PBI Cost-Effectiveness by Step

Steps 1 & 2	TRC	PACT	PCT	RIM	SCT
NPV Benefits	$15,472,594	$4,526,495	$17,245,264	$4,526,495	$14,342,450
NPV Costs	$9,791,438	$3,342,547	$9,632,004	$11,500,647	$9,794,770
NPV Net Benefits	$5,681,155	$1,183,948	$7,613,260	-$6,974,152	$4,547,680
B/C Ratio	1.58	1.35	1.79	0.39	1.46
Step 3	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$30,166,951	$9,342,362	$31,175,284	$9,342,362	$29,887,824
NPV Costs	$18,004,587	$5,060,502	$17,006,612	$22,035,779	$18,628,283
NPV Net Benefits	$12,162,364	$4,281,860	$14,168,672	-$12,693,417	$11,259,541
B/C Ratio	1.68	1.85	1.83	0.42	1.60
Step 4	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$86,980,583	$27,172,556	$84,326,103	$27,172,556	$88,896,370
NPV Costs	$50,341,821	$11,252,034	$45,905,457	$61,081,212	$53,865,689
NPV Net Benefits	$36,638,762	$15,920,522	$38,420,646	-$33,908,656	$35,030,681
B/C Ratio	1.73	2.41	1.84	0.44	1.65
Step 5	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$80,865,046	$24,900,746	$75,731,239	$24,900,746	$81,948,996
NPV Costs	$46,058,804	$7,179,381	$42,007,137	$52,842,502	$49,282,690
NPV Net Benefits	$34,806,242	$17,721,365	$33,724,103	-$27,941,756	$32,666,306
B/C Ratio	1.76	3.47	1.80	0.47	1.66
Step 6	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$67,302,223	$20,699,908	$59,065,610	$20,699,908	$69,915,568
NPV Costs	$37,633,021	$3,800,197	$32,956,777	$41,938,789	$41,647,855
NPV Net Benefits	$29,669,203	$16,899,711	$26,108,833	-$21,238,881	$28,267,713
B/C Ratio	1.79	5.45	1.79	0.49	1.68
Step 7	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$132,710,393	$41,643,032	$115,468,800	$41,643,032	$140,991,499
NPV Costs	$73,251,838	$6,325,914	$64,085,706	$83,051,212	$81,092,192
NPV Net Benefits	$59,458,554	$35,317,119	$51,383,093	-$41,408,179	$59,899,307
B/C Ratio	1.81	6.58	1.80	0.50	1.74

For the PBI, the CGB OF returned a result of 44.3 kWh/$, with strong growth observed in each subsequent step of the program.

Table 24. Objective Function Results by Step for PBI

	Lifetime kWh	Program Administration Costs	Objective Function (kWh/$)
Steps 1 & 2	54,530,464	$3,342,547	16.31
Step 3	115,378,769	$5,060,502	22.80
Step 4	343,902,895	$11,252,034	30.56
Step 5	315,150,283	$7,179,381	43.90
Step 6	268,439,861	$3,800,197	70.64
Step 7	540,033,788	$6,325,914	85.37
Total	**1,637,436,060**	**$36,960,574**	**44.30**

RSIP Overall

Overall, the RSIP provided far more benefits than costs from a variety of perspectives. RSIP passed all cost-effectiveness tests except the RIM test which most programs, including energy efficiency programs, do not pass[66]. In terms of leveraging non-Green Bank funds, RSIP provided $3.05 of benefits for every $1.00 spent on programs and related costs (reflected in the PACT result), while still supporting strong industry growth and maintaining positive customer economics for residential PV installations (see PCT result).

Table 25. EPBB and PBI Combined Cost-Effectiveness

	TRC	PACT	PCT	RIM	SCT
Installed Capacity (MW)	91.3 MW_{DC}				
NPV Benefits	$618,994,562	$210,410,423	$596,514,388	$210,410,423	$685,462,023
NPV Costs	$364,837,887	$69,057,692	$331,819,540	$455,144,337	$390,979,712
NPV Net Benefits	$254,156,675	$141,352,731	$264,694,849	-$244,733,913	$294,482,311
B/C Ratio	1.70	3.05	1.80	0.46	1.75

As with the separate RSIP EPBB and PBI results, the effectiveness of Green Bank funds disbursed for the program as a whole, as reflected by the PACT, increased over the program's life, growing from 1.50 in Step 1 to 6.47 by Step 7. Leveraging in Step 7 is approaching 7:1 for the PACT, while generally maintaining cost-effectiveness for participants.

[66] The RIM test, as noted previously, accounts for lost utility revenue and assumes that the cost is redistributed among all ratepayers. More often than not, any measure that reduces the utility's sale of electricity will fail to pass the RIM test, regardless of societal or total resource cost-effectiveness. Load shifting and demand reduction programs are more likely to pass the RIM test.

Table 26. EPBB and PBI Combined Cost-Effectiveness by Step

Steps 1 & 2	TRC	PACT	PCT	RIM	SCT
NPV Benefits	$50,215,714	$18,646,724	$58,718,002	$18,646,724	$57,193,553
NPV Costs	$34,855,715	$12,435,693	$34,232,074	$46,154,815	$34,859,057
NPV Net Benefits	$15,359,999	$6,211,031	$24,485,929	-$27,508,091	$22,334,496
B/C Ratio	1.44	1.50	1.72	0.40	1.64
Step 3	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$87,080,246	$32,714,259	$92,846,353	$32,714,259	$102,690,567
NPV Costs	$54,731,346	$15,784,621	$51,588,058	$75,421,848	$56,620,843
NPV Net Benefits	$32,348,900	$16,929,638	$41,258,295	-$42,707,590	$46,069,723
B/C Ratio	1.59	2.07	1.80	0.43	1.81
Step 4	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$138,148,269	$47,901,194	$135,769,504	$47,901,194	$155,070,461
NPV Costs	$81,291,431	$18,200,235	$74,084,230	$106,222,919	$86,992,820
NPV Net Benefits	$56,856,838	$29,700,959	$61,685,273	-$58,321,725	$68,077,640
B/C Ratio	1.70	2.63	1.83	0.45	1.78
Step 5	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$103,975,954	$33,822,171	$98,226,550	$33,822,171	$110,377,878
NPV Costs	$59,858,717	$9,467,372	$54,575,232	$71,568,644	$64,058,491
NPV Net Benefits	$44,117,237	$24,354,799	$43,651,318	-$37,746,474	$46,319,387
B/C Ratio	1.74	3.57	1.80	0.47	1.72
Step 6	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$94,297,186	$31,078,515	$84,035,236	$31,078,515	$103,934,514
NPV Costs	$53,483,189	$6,021,396	$46,816,113	$63,376,792	$59,203,717
NPV Net Benefits	$40,813,996	$25,057,119	$37,219,122	-$32,298,277	$44,730,797
B/C Ratio	1.76	5.16	1.80	0.49	1.76
Step 7	**TRC**	**PACT**	**PCT**	**RIM**	**SCT**
NPV Benefits	$145,277,194	$46,247,561	$126,918,744	$46,247,561	$156,195,051
NPV Costs	$80,617,489	$7,148,375	$70,523,832	$92,399,318	$89,244,784
NPV Net Benefits	$64,659,705	$39,099,186	$56,394,912	-$46,151,757	$66,950,267
B/C Ratio	1.80	6.47	1.80	0.50	1.75

The Green Bank Objective Function results for EPBB and PBI combined parallel the findings from the cost-effectiveness tests, in particular the PACT, with increasing efficiency in the use of program funds over the life of the program. The energy produced for every dollar invested increases from 18.1 kWh/$ in Steps 1&2 to 83.9 kWh/$ in Step 7, and 38.7 kWh/$ to date for RSIP overall.

Table 27. RSIP EPBB and PBI Combined Results for Connecticut Green Bank Objective Function

CGB RSIP 2012-2015 Objective Function	Residential Solar PV Capacity (MW)	Lifetime kWh	Program Costs	Objective Function (kWh/$)
Steps 1 & 2	7.4	225,385,736	$12,435,693	18.1
Step 3	13.3	405,346,549	$15,784,621	25.7
Step 4	20.5	607,500,605	$18,200,235	33.4
Step 5	14.8	428,600,431	$9,467,372	45.3
Step 6	14.0	403,698,026	$6,021,396	67.0
Step 7	21.4	600,041,849	$7,148,375	83.9
Total	91.3	2,670,573,196	$69,057,692	38.7

Taken together, the cost-effectiveness tests and the Green Bank Objective Function tell a consistent story – that efficiency in the use of program funds is increasing as the program progresses from step 1 through step 7, as represented by PACT and Green Bank Objective Function results, while the PCT which reflects the benefit/cost ratio for the participant stays level.

Table 28. RSIP Cost-Effectiveness Results for the Five Standard Tests and the Connecticut Green Bank Objective Function

CGB RSIP 2012-2015	TRC	PACT	PCT	RIM	SCT		CGB OF (kWh/$)
Steps 1 & 2	1.44	1.50	1.72	0.40	1.64		18.1
Step 3	1.59	2.07	1.80	0.43	1.81		25.7
Step 4	1.70	2.63	1.83	0.45	1.78		33.4
Step 5	1.74	3.57	1.80	0.47	1.72		45.3
Step 6	1.77	5.16	1.80	0.49	1.76		67.0
Step 7	1.58	6.47	1.57	0.50	1.75		83.9
Total	1.65	3.05	1.75	0.46	1.75		38.7

Costs and Benefits of Net Metering

Though not the focus of this study, the costs and benefits of net metering programs is closely related to the cost-effectiveness of the RSIP, and similar programs. In this section, we provide a brief discussion of net metering costs and benefits, as they apply to residential PV systems in Connecticut. This is intended only as an overview, however, and additional research is required to fully explore and quantify the costs and benefits of net metering and such an analysis is beyond the scope of the present study. The information in this section is provided for informational reference only.

The costs and benefits of net metering are widely debated by utilities, solar advocates, and others. For the purpose of this study, we did not attempt to directly assess the cost effectiveness of the utility's net metering programs. However, the discussion below explains that the majority of both the benefits and costs of net metering are already incorporated in the cost-effectiveness calculations in this study, with some exceptions described below.

Net Metering Benefits

The benefits of net metering include an offset of electricity purchases by program participants (i.e., participants who have solar PV systems are purchasing less electricity from the utility). This benefit is already included in the PCT. For purposes of this report, we have assumed that generation does not exceed consumption on an annual basis for any customer.[67] This precludes the possibility of utilities providing a payment (on a net, annual basis) to customers and the need to discern at what rate that payment would be made. All bill reduction benefits are accrued at the rate the customer otherwise would have paid to their utility for the equivalent amount of electricity (i.e., the retail rate).

The broader benefits of net metering include an offset of (avoided) energy and capacity costs, with associated embedded environmental benefits and non-energy benefits; these benefits are included in the TRC and SCT tests. We have not included in any of the tests the benefits of reducing the utility's alternative compliance payments (ACP) for failing to meet relevant Renewable Portfolio Standard targets.

Net Metering Costs

While we did not survey the Connecticut utilities to gather cost data, we have generally accounted for the costs of net energy metering (NEM) to participating utilities. Note that it is likely that participating utilities have not fully assessed the costs of administering NEM programs. We note that:

[67] There are solar PV systems sized larger than needed to meet customer usage. RSIP experience is that these customers usually anticipate greater electricity usage in the future; possible reasons for this are installation of ductless mini-split heat pumps, geothermal systems, purchase of an electric vehicle, other equipment purchases or upgrades and/or an increase in family size. If, however, electricity generation did exceed usage on an annual basis, net metering would compensate the customer for any excess credits at year end (March billing period) at the wholesale (not retail) electricity rate.

- The vast majority of the cost to utilities for NEM programs is the lost energy and distribution system revenue associated with not selling kWh. For general scale, the lifetime generation of a 7 kW PV system[68] results in savings of roughly $30,000-$40,000 in lost revenue for the utility, based on lifetime generation times the utility retail rate. Line losses need not be included as the basis of comparison (electricity consumption) and generation both occur on the customer side of the meter. This lost revenue is included as a cost on the RIM test.
- Other administrative costs are typically small compared to the lost revenue and include about $280 of costs per system, as follows. In context, this $280 is approximately 1% of the cost associated with lost revenue.
  - Application processing (approximately $140): Eversource CT charges a $100 fee for residential application reviews, which covers the majority (but not all) of the labor associated with processing residential interconnection applications.
  - Billing ($0): Since these are residential customers, not remote net metering applications, we are assuming there is no additional billing cost associated with NEM vs. non NEM customers.
  - Metering (approximately $140): Most customers require a meter change from a regular to a "net meter". Since utilities regularly maintain/replace metering and this process is not time-consuming for their technicians, the estimated cost of meter exchange labor is $42. The incremental cost of a net meter is $98.

Our analysis has not incorporated the administrative costs of net metering but, as noted above, incorporates the majority of net metering costs through the treatment of participant bill savings as a cost (i.e., lost revenue) on the RIM test. To more accurately assess the cost-effectiveness of the utility net metering programs is outside the scope of the current study.

[68] The average system size in the RSIP dataset analyzed for this study was 7.44 kW.

Cost-Effectiveness of Energy Efficiency Programs

To provide results that would be meaningful to policymakers looking at cost-effectiveness broadly for all programs in Connecticut, the aim was to conduct this evaluation using assumptions as consistent as possible with those used in the analysis of the energy efficiency programs delivered by the Connecticut IOU utilities. However, there remained differences between the processes used to derive the solar PV cost-effectiveness ratios in this report and those used by the utilities to calculate cost-effectiveness for energy efficiency. As a result, although solar PV and energy efficiency were both shown to be cost-effective, a direct comparison is not presented in this report.

This report section presents the cost-effectiveness results for energy efficiency and explains some of the differences in the assumptions and methodologies used to determine solar PV and energy efficiency benefit/cost ratios. The energy efficiency results are also included in the subsequent report section "Cost-Effectiveness of Bundled Technologies" in which an example calculation illustrates that one can combine measures that are cost-effective (e.g., solar PV and energy efficiency) with those not yet cost-effective (e.g., energy storage) to encourage adoption of more comprehensive energy solutions for participants while maintaining cost-effectiveness.

Table 29 presents cost-effectiveness ratios for Eversource's[69] energy efficiency programs for 2016 from the 2016-2018 Electric and Natural Gas Conservation and Load Management (CL&M) Plan[70], almost all of which are shown to be cost-effective.[71]

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[69] Three years ago, Northeast Utilities and its operating companies Connecticut Light & Power, Public Service of New Hampshire, Western Massachusetts Electric and Yankee Gas merged with NSTAR Electric & Gas. In 2015, the company and all of its subsidiaries changed their names to Eversource Energy. Eversource currently serves approximately 85% of electricity customers in Connecticut and is considered representative of the state's market.

[70] As provided in the 2016-2018 Electric and Natural Gas Conservation and Load Management (CL&M) plan filed with the Connecticut Department of Energy and Environmental Protection on October 1, 2015, available at http://www.energizect.com/about/eeboard/plans (the numbers could be updated before the Plan is finalized), Table B1, Eversource CT Electric – Costs and Benefits 2016. The PACT and M-PACT correspond to the Electric Utility Cost Test and Modified Utility Cost Test from the CL&M Plan. The electric utility cost test includes electric benefits and costs, while the modified utility cost test includes oil and propane savings and costs. The electric utility cost test is used as an example for combining with solar PV benefits and costs (in the next section on technology bundling) but both tests are shown here to illustrate that the EE measures have non-electric impacts (that usually increase the ratios). The residential EE programs are designed to maximize not just electricity, but all fuel savings, including oil, gas and propane. If the technology bundle considered in the next section included non-electric impacts, the M-PACT could be more appropriate for use in calculating the cost-effectiveness of the technology bundle.

[71] A few exceptions are: the TRC ratio for HES HVAC, and the UCT/PACT and modified UCT/PACT ratios for HES Income Eligible. The HVAC measure costs tend to be higher than those for other EE programs. For the HES Income Eligible program, incentives typically cover 100% of the measure costs, resulting in lower UCT/PACT ratios.

Table 29. Eversource 2016 Residential Energy Efficiency Program Cost-Effectiveness

Program, Year		Test	Benefits	Costs	Net Benefits	Ratio
EE 2016 Eversource	Residential Total	TRC	$186,853,379	$76,049,054	$110,804,325	2.46
		PACT	$89,622,927	$40,686,706	$48,936,221	2.20
		M-PACT	$133,786,974	$56,458,769	$77,328,205	2.37
	Residential Retail Products	TRC	$82,271,005	$24,792,006	$57,478,999	3.32
		PACT	$51,489,640	$13,622,165	$37,867,475	3.78
		M-PACT	$51,489,640	$13,622,165	$37,867,475	3.78
	Home Energy Solutions (HES)	TRC	$62,298,317	$19,090,656	$43,207,661	3.26
		PACT	$17,138,430	$9,467,560	$7,670,870	1.81
		M-PACT	$51,721,547	$17,965,248	$33,756,299	2.88
	HES HVAC	TRC	$5,794,248	$6,679,885	($885,637)	0.87
		PACT	$3,982,333	$2,000,000	$1,982,333	1.99
		M-PACT	$3,982,333	$2,000,000	$1,982,333	1.99
	HES Income Eligible	TRC	$22,914,543	$17,713,445	$5,201,098	1.29
		PACT	$8,853,029	$10,728,336	($1,875,307)	0.83
		M-PACT	$16,873,190	$17,459,712	($586,522)	0.97
	New Construction	TRC	$6,442,405	$4,773,062	$1,669,343	1.35
		PACT	$3,198,174	$1,868,646	$1,329,528	1.71
		M-PACT	$4,758,944	$2,411,645	$2,347,299	1.97
	Behavior	TRC	$7,132,861	$3,000,000	$4,132,861	2.38
		PACT	$4,961,321	$3,000,000	$1,961,321	1.65
		M-PACT	$4,961,321	$3,000,000	$1,961,321	1.65

As previously stated, RSIP cost-effectiveness is not directly compared to those of energy efficiency programs in this report because of differences in the methodologies used to calculate these benefit/cost ratios and the contexts in which these ratios are generated and utilized, as further described here.

First, RSIP and Connecticut's energy efficiency programs operate under different mandates. RSIP has a legislative target to install 300 MW of residential solar PV by 2022. The legislation also specifies that incentives are to decline over time to foster sustained, orderly development of a state solar PV industry.[72] Incentives are the dominant program cost for RSIP and reducing these incentives over time

[72] In 2011, Connecticut's legislature passed Public Act 11-80, which created the Connecticut Green Bank pursuant to Connecticut General Statute (CGS) 16-245n and tasked it with creation of the Residential Solar Investment Program (RSIP) (CGS 16-245ff) which was to result in installation of 30 MW of new residential solar PV by 2022, funded by no more than one-third of the total annual surcharge collected from customers of electric services, and providing "incentives that decline over time and will foster the sustained, orderly development of a state-based solar industry." RSIP met the 30 MW target eight years ahead of schedule, in 2014. Governor's Bill No. 6838, "An Act Concerning the Encouragement of Local Economic Development and Access to Residential Renewable Energy,"

by increasing project financing by program participants is expected to result in lower program costs and lower program costs relative to benefits, resulting in an increasing cost-effectiveness ratio from a program administrator (i.e., CGB) perspective (the program administrator cost test).[73] Simultaneous to lowering incentives, the Green Bank has supported strategic initiatives within RSIP to encourage increased deployment of residential solar PV, including Green Bank financing products such as the Smart-E Loan[74], the CT Solar Loan[75] and the CT Solar Lease[76], the Solarize Program (a volume discount program that pairs up installers and municipalities to provide lower prices the more customers sign up for solar PV), as well as marketing, outreach and educational efforts within and outside of Solarize. The Green Bank looks at this from the perspective of how can the Green Bank deploy more with less, an approach also reflected by the Green Bank focus on leveraging financing, in particular private capital, to deploy more clean energy with fewer public resources.

The Connecticut's two investor-owned utilities administer the state's energy efficiency programs with a different mandate, with the goal of acquiring all cost-effective energy efficiency. This necessitates that the programs be delivered within the residential, commercial, and industrial sectors within the Eversource and UI service territories. Measures with cost-effectiveness ratios of 1.0 or greater (and under specific conditions measures with lower ratios) are all included in the energy efficiency planning effort. In Connecticut, as overseen by the Energy Efficiency Board (EEB), energy efficiency plans are developed by the utilities for three year periods, including budgets, deployment targets, and anticipated benefits and costs for the entire portfolio of energy efficiency measures. This planning effort is informed by impact evaluations and other research studies, and there is consideration of appropriate incentive levels for measures in the portfolio. Therefore, the benefit/cost ratios for energy efficiency programs are calculated and utilized in a context that considers a different set of complexities than does the RSIP.

A second key difference between the cost-effectiveness analysis of RSIP and that of the energy efficiency programs conducted by the utilities pertains to program attribution assumptions. As stated in

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was signed into law July 2, 2015 by Governor Malloy, expanding the RSIP target from 30MW to 300MW by 2022 and establishing the Solar Home Renewable Energy Credit (SHREC) a new type of Class I REC which utilities are to purchase from the Green Bank through 15-year contracts as a funding source for RSIP (this bill updates CGS 16-245ff). Governor's Bill No. 6838: https://www.cga.ct.gov/2015/TOB/h/pdf/2015HB-06838-R00-HB.pdf, and CGS chapter 283, section 16-245ff: https://www.cga.ct.gov/current/pub/chap_283.htm.

[73] Taking into account program attribution considerations as incentives decrease, as well as potential market transformation effects described in the Program Attribution section (in the Methodology section of this report).

[74] Smart-E Loans offer no money down, low-interest financing with flexible terms for almost any residential energy improvement project including solar PV, and energy efficiency measures such as insulation, window replacement, HVAC and water heating upgrades, and purchase of Energy Star appliances. Lower rates are offered for Smart-E technology bundles that combine two or more qualifying measures. The loans are provided through local, participating lenders. See: www.energizect.com/SmartE, or www.energizect.com/SmartEBundle.

[75] The CT Solar Loan is no longer available and has been transitioned to a private capital partner. Read more about this at: http://www.prnewswire.com/news-releases/ct-solar-loan-partner-graduates-from-connecticut-green-bank-280780492.html.

[76] The CT Solar Lease is no longer available, though other leases and power purchase agreements are available in the Connecticut market for customers who choose to adopt solar PV through a third-party provider.

an earlier section of the report, for RSIP, Cadmus made a simplifying assumption to use a net to gross ratio of one for this study. Net to gross ratios for residential energy efficiency measures are obtained within the context of an independent impact evaluation of the residential programs for a specified program period. The ratios typically do not equal 1.0, and are often less than 1.0. These values are used as inputs in the program planning process, unless program design or the target market are expected to change sufficiently that they would no longer represent the expected future interplay of free riders and spillover; net to gross ratio values would then be re-assessed as needed.

A third aspect of difference between this RSIP evaluation and the evaluation of Connecticut energy efficiency programs conducted by the utilities pertains to the existence and treatment of federal tax credits and accelerated depreciation in cost-effectiveness tests. Solar PV projects are afforded significant federal tax incentives, which are included in the cost-effectiveness calculations for RSIP, including a 30% investment tax credit (ITC) and an accelerated depreciation benefit called MACRS[77] for third party owned projects, treated as benefits in the TRC and PCT tests. Federal tax incentives for energy efficiency are generally lower. Certain energy efficiency projects qualify for a 10% federal tax credit but with a maximum credit of $500 or lower depending on the measure, and there is no accelerated depreciation benefit.[78] Connecticut energy efficiency program cost-effectiveness tests do not account for federal tax credits or accelerated depreciation.[79]

[77] MACRS (Modified Accelerated Cost Recovery System) is a Federal tax benefit that allows businesses to claim the depreciated value of solar assets as a tax deduction over a five year period. For more information: http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs.

[78] https://www.energystar.gov/about/federal_tax_credits

[79] Treatment of tax credits varies among jurisdictions and can be modeled either as a transfer payment with neutral impact on cost effectiveness, or as a reduction in costs or as an increase in benefits.

Cost-Effectiveness of Bundled Technologies

With both residential solar PV and residential energy efficiency programs shown to be cost-effective, the Green Bank wanted to consider the opportunity to bring together a suite of technologies that could provide more comprehensive energy solutions for customers and benefits to the grid while still maintaining overall cost-effectiveness. Bundling technologies together would leverage the cost-effectiveness of more mature technologies, solar PV and energy efficiency, to support investment in promising technologies such as energy storage that are of strong interest to customers but have not yet achieved commercial cost-effectiveness.[80] This strategy works because the benefits of solar PV and energy efficiency far enough outweigh the costs to provide the opportunity to add additional costs into the ratio.

For a typical residential customer in Connecticut, we have bundled energy efficiency, solar PV, and energy storage into a single combined resource and calculated the cost-effectiveness of the resulting resource mix. For energy efficiency and PV, we calculated average benefits and costs per participant for the Home Energy Solutions and RSIP (Step 7), respectively.

Home Energy Solutions (HES) is a residential energy efficiency program operated by the Connecticut utilities and includes a wide variety of energy efficiency measures and activities beginning with an in-home energy assessment. Core measures include a blower door test before and after implementation of air and duct sealing. The assessment also includes lighting upgrades and identification of further and deeper energy savings opportunities in the home such as insulation, appliance and HVAC upgrades for which participants have access to incentives and financing. Although our analysis does not stipulate exactly which measures are installed, we are using the average benefits and costs per participant, which represents a mix of basic and more advanced efficiency measures.

For modeling purposes, we have assumed the energy storage portion of the bundle is the leased Tesla PowerWall 7 kWh home energy storage system. Although this unit is somewhat more expensive than current lead acid based battery systems, the popularity of the product line and offerings by major vendors make it a reasonable choice for potential future residential scale energy storage products that may be of interest to typical Connecticut customers.

[80] During an earlier evaluation of the RSIP completed by Cadmus in January 2015, Cadmus found that approximately 59% of customers surveyed indicated that they were also interested in energy storage. Of the customers surveyed, however, only 5% had actually installed an energy storage system. (Note that these findings were collected as part of the survey but not presented in the report, referenced below). This high level of interest suggests that customers want to combine energy storage with their PV systems, though there is not enough information to gauge the value they would place on such an offering. Based on the preliminary analysis presented here, customers would be interested in energy storage and the excess cost-effectiveness of RSIP and energy efficiency technologies may be able to support the deployment of storage technologies while maintaining cost-effectiveness. "Residential Solar Investment Program Evaluation," Shawn Shaw, Danielle Kolp, Mary Knipe, Ryan Fahey, Kathleen Higgins, The Cadmus Group, January 28, 2015. http://www.ctgreenbank.com/wp-content/uploads/2016/02/RSIP_Evaluation_I_Final_Report_and_cvr_ltr.pdf

Table 30 shows the RSIP and energy efficiency benefit and cost data used as a starting point in the technology bundling analysis. These benefits and costs were then divided by the number of participants for each program to derive per-participant benefits and costs, shown in Table 31.

Table 30. RSIP and Energy Efficiency Benefits and Costs

Program	Test	# Participants	Benefits	Costs	Net Benefits
RSIP 2015 Step 7	TRC	2,639	$145,277,194	$80,617,489	$64,659,705
	PACT	2,639	$46,247,561	$7,148,375	$39,099,186
	PCT	2,639	$126,918,744	$70,523,832	$56,394,912
EE 2016 Eversource – Home Energy Solutions (HES)[81]	TRC	17,320	$62,298,317	$19,090,656	$43,207,661
	PACT	17,320	$17,138,430	$9,467,560	$7,670,870
	PCT	17,320	$33,476,738	$1,125,408	$32,351,330

For example, for the TRC, taken on a per-participant basis, the RSIP and Home Energy Solutions programs provide lifetime net benefits of approximately $24,500 and $2,500, respectively, or almost $27,000 in total (see Table 31).

Table 31 shows the TRC, PACT and PCT ratios for the technology bundle that includes solar PV, energy efficiency, and energy storage. The cost of energy storage is based on a reported customer cost of $5,000 for a nine year leased PowerWall[82]. For the PACT, Cadmus assumed an 8% or $400 program administration cost. The benefits are conservatively estimated to be zero since we did not attempt to monetize the value of storage (see the next section of this report on valuing energy storage). The resulting net benefits of the technology bundle are still almost $21,600, and the resulting TRC ratio is still over unity, specifically 1.58. Similarly, the PACT and PCT ratios also exceed unity for the technology bundle. In fact, the ratios could absorb additional cost; the amount of net benefits for the RSIP plus Home Energy Solutions programs for each ratio indicates the amount of additional cost that could be added and still achieve a ratio of at least unity.

[81] The total customer costs and number of measures/participants for HES were taken from the 2016-2018 CL&M Plan, Table B2 – Eversource CT Electric – Resource Summary 2016. Benefits were estimated by multiplying the lifetime savings in MWh attributed to HES and multiplying by 19.23 cents per kWh, the Energy Information Administration (EIA) average residential price of electricity in CT for September 2015 (from the Electric Power Monthly Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2015 and 2014).

[82] Note that the installed cost of $5000 used here is for a system leased over nine years. In comparison to a 7 kWh system provided through a Green Mountain Power program in Vermont which has a purchase and a lease option, this cost is lower than the purchase price of $6501 and higher than the lease option of $1.25/day (which amounts to $4106.25 over a nine year period). Additionally, there is sufficient benefit from the RSIP and HES programs to accommodate a higher cost in the case of a larger or more expensive energy storage system, or the addition of other measures.

Effectively, the high level of benefits provided by the RSIP and HES programs can be used to offset the lower cost-effectiveness of an emerging technology such as energy storage. While the benefits of energy storage were assumed to be zero in this example, indication of value is provided by customer interest and willingness to pay. Depending on how energy storage is configured with solar PV, and the presence of energy management software, energy storage along with solar PV could contribute to peak load reduction more than solar PV by itself, and there are additional values to the grid that could potentially be monetized in the future (e.g., supporting time of use rate structures for solar PV + storage customers). Energy storage could therefore be an important component of a technology bundle that provides a comprehensive energy solution to customers and value to the electricity system.

Table 31. Cost-Effectiveness of a Technology Bundle[83]

Program	Test	Benefits/ Participant	Costs/ Participant	Net Benefits/ Participant	Ratio
RSIP 2015 Step 7	TRC	$55,050	$30,548	$24,502	1.80
	PACT	$17,525	$2,709	$14,816	6.47
	PCT	$48,093	$26,724	$21,370	1.80
EE 2016 Eversource – Home Energy Solutions (HES)	TRC	$3,597	$1,102	$2,495	3.26
	PACT	$990	$547	$443	1.81
	PCT	$1,933	$65	$1,868	29.75
RSIP 2015 Step 7 + EE 2016 Eversource HES	TRC	$58,647	$31,651	$26,996	1.85
	PACT	$18,514	$3,255	$15,259	5.69
	PCT	$50,026	$26,789	$23,238	1.87
Energy Storage	TRC	$0	$5,400	($5,400)	0.00
	PACT	$0	$400	($400)	0.00
	PCT	$0	$5,000	($5,000)	0.00
RSIP 2015 Step 7 + Storage	TRC	$55,050	$35,948	$19,102	1.53
	PACT	$17,525	$3,109	$14,416	5.64
	PCT	$48,093	$31,724	$16,370	1.52
RSIP 2015 Step 7 + EE 2016 Eversource HES + Storage	TRC	$58,647	$37,051	$21,596	1.58
	PACT	$18,514	$3,655	$14,859	5.06
	PCT	$50,026	$31,789	$18,238	1.57

[83] Though the PCT is not calculated in the EE CL&M plans, enough data were provided to estimate the PCT for the HES Program for the purposes of this example bundling calculation. The total customer costs and number of measures/participants for HES were taken from the 2016-2018 CL&M Plan, Table B2 – Eversource CT Electric – Resource Summary 2016. Benefits were estimated by multiplying the lifetime savings in MWh attributed to HES and multiplying by 19.23 cents per kWh, the Energy Information Administration (EIA) average residential price of electricity in CT for September 2015 (from the Electric Power Monthly Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2015 and 2014). This resulted in HES per participant benefits of $1933, and costs of $65, resulting in a highly favorable PCT of 29.75. The ratio could have been higher if the benefits estimate calculation included an escalator for the price of electricity and if the peak kW impact was included benefit estimate, but the simplified calculation already yielded highly favorable results that were sufficient to illustrate the benefit of bundling technologies. The per participant HES cost of $65 is lower than the expected $99 (the per participant contribution to the HES Program as typically advertised); this is because some of the costs for homes utilizing gas are allocated to the respective gas budget in the CL&M plan.

Noteworthy technology bundling programs are being implemented in Vermont, deploying energy efficiency, solar PV, energy storage, and renewable heating technologies in various combinations to provide comprehensive energy improvements to customers.

- Green Mountain Power (GMP) is offering energy storage using the Tesla Powerwall with or without solar PV[84]: "The Tesla home battery can be paired with small-scale solar such as rooftop panels to store locally generated energy, or it can be used without solar as a battery to store power from the grid. During a storm or emergency, the battery is able to power essential parts of the home like lights, a refrigerator, and heat pump (or heating system). GMP will partner with customers to utilize the batteries during peak energy times to directly lower costs for customers by reducing transmission and capacity costs." The 7 kWh Powerwall offered by GMP provides four to six hours of backup power and can be purchased for $6501, or leased for $1.25 per day.
- Zero Energy Now! (ZEN)[85] is a comprehensive home energy improvement program in Vermont offered through the Building Performance Professionals Association of Vermont in collaboration with Green Mountain Power. The program offers energy efficiency upgrades, renewable heating options, solar photovoltaics, and energy storage in order to significantly reduce each customer's energy costs. Participating ZEN contractors assist customers to develop a comprehensive package of energy improvements. The threshold for participation includes the ability to obtain at least a 10% reduction in the heating load, a reduction in annual MMBtu per year of total fossil fuel and electric energy usage of at least 50%, and adoption of a renewable heating system (such as those based on biomass or heat pump technology) designed to meet at least 50% of the load of the house. The ZEN web site illustrates the use of financing to pay for the package, using an example of a home equity product available from a local lender.

Also note that the Green Bank Smart-E Loan Program[86] mentioned earlier in the report offers financing for almost any residential energy improvement project including solar PV, and energy efficiency measures such as insulation, window replacement, HVAC and water heating upgrades, and purchase of Energy Star appliances, with lower rates offered for Smart-E technology bundles that combine two or more qualifying measures. These loans are provided through local, participating lenders.

Valuing Energy Storage

Note that, in the analysis of RSIP, we have assumed no monetized benefits for energy storage. As of this report, there is no market in Connecticut for the many grid support and ancillary services that can be provided by distributed energy storage technologies. Examples of these services include:

- Frequency regulation
- Reactive power
- Voltage support
- Arbitrage

[84] http://products.greenmountainpower.com/tesla-powerwall.html, http://www.triplepundit.com/2015/12/green-mountain-power-now-leasing-selling-teslas-powerwall.

[85] http://zen-vt.com.

[86] www.energizect.com/SmartE, or www.energizect.com/SmartEBundle.

The value of these ancillary services varies widely and is a rapidly developing aspect of the changing electricity market. Well-known utility restructuring programs, such as New York's REV initiative, are working to understand and develop a market-based approach to funding energy storage projects but these efforts have not yet been fully realized and, absent these revenue streams, a customer purchasing a residential energy storage system in Connecticut today can expect to realize only the benefits associated with having backup power available in the event of a utility outage. As these outages are typically infrequent and of short duration, we have not assigned a monetary benefit, though many customers do express a willingness to pay for this convenience so there is an indeterminate customer-driven value placed on energy resilience.

During Cadmus' evaluation of the RSIP, completed in January 2015, approximately 59% of customers surveyed indicated that they were also interested in energy storage[87]. Of the customers surveyed, however, only 5% had actually installed an energy storage system. This high level of interest suggests that customers want to combine energy storage with their PV systems, even though there is not enough information to gauge the value they would place on such an offering. Attempting to monetize this benefit is beyond the scope of this study but may be worth further research as the energy storage industry develops in Connecticut. Based on the preliminary analysis presented here, customers would be interested in energy storage and the excess cost-effectiveness of the RSIP may be able to support the deployment of storage technologies, while maintaining programmatic cost-effectiveness.

The Role of Enabling Technologies in PV Market Development

As noted previously, the large net benefits associated with residential PV projects under the RSIP may afford an opportunity for the bundling of emerging technologies that can capitalize on these net benefits and, in turn, provide a mutually beneficial resource bundle that promotes long term growth of several distributed energy technologies.

Enabling technologies, which can ultimately make PV more cost-effective, include:

Energy Storage

Energy storage, most commonly in the form of batteries at the residential scale, has been used for many years in combination with solar PV, particularly in off-grid or niche applications requiring minimal downtime. Historically, these applications have not sought to provide cost-effective energy or demand savings to the host site but have been installed to meet other objectives. More recently, the cost of energy storage has declined rapidly, while new utility revenue sources have simultaneously become available. This combination, supported by favorable public policies in California and elsewhere, has made cost-effective distributed energy storage feasible in some applications. While Connecticut has not yet developed the infrastructure to allow for some of the possible benefits associated with distributed energy storage, key synergies with solar PV systems include:

[87] Note that these data were not included in the final report.

- Peak load shifting: For most PV systems in Connecticut, the peak output occurs from approximately 11AM to 2PM, while the utility peak demand period occurs from approximately 3PM to 6PM. An appropriately sized battery system could be configured to charge during peak solar output and dispatch that same electricity (less conversion losses) a few hours later when the electricity is much more valuable to the grid. Combined with smart metering (discussed below) and time of use rates, this presents a potential opportunity to increase the net value of PV systems to customers and utilities. In commercial settings, solar PV plus energy storage can provide value in reducing demand charges for customers whose utilities allow the connection of grid-parallel energy storage systems.
- Backup power: This is the most traditional application for PV systems with built in battery storage. While in residential applications the monetary value of this benefit is difficult to calculate, in commercial/industrial applications the value of backup power is quantifiable in terms of otherwise lost productivity.
- Grid support: Many utilities are implementing large-scale energy storage systems (e.g., vanadium redox flow batteries) as means of grid support. These large battery systems, with long cycle lifetimes and rapid cycling capability, can provide a variety of grid support benefits including voltage regulation, frequency regulation, and reactive power. While this application is probably a mid-term option for residential systems, further investigation may suggest more near term applicability.

Smart Metering

Smart metering is a broad term describing an infrastructure consisting of communication-enabled customer energy meters, data centers, internet connectivity, and software for managing and analyzing large sets of data. The purpose of the technology, overall, is to provide real-time data on customer electricity use. This can facilitate several important benefits:

- Reduced billing costs: Smart meters, with an advanced metering infrastructure (AMI) can automatically report customer consumption for billing purposes, allowing utilities to reduce administrative costs associated with collecting and documenting meter readings.
- Energy conservation: By providing customers with real-time feedback on consumption and, in some cases, pricing, customers may adjust their energy-consuming behavior. This can provide both cost savings to the customer and relief for utilities during peak usage periods.
- Time of use pricing: With smart meter technologies, residential time of use rates become much more feasible to implement. This presents a more realistic value proposition for large-scale adoption of solar PV, since the generated electricity will be valued based on system needs rather than a flat net metering rate. It also presents the PV industry with a differing set of design constraints. For example, if peak afternoon pricing is sufficiently attractive, customers may elect to orient systems in a south-western direction to take advantage of pricing signals, even though overall annual production may be slightly lower than for a south facing PV system of the same size.
- Other benefits: An integrated AMI can also provide more rapid feedback on outages, targeted data for distribution upgrades, reduction in unaccounted for energy consumption, remote service disconnect/re-connect functions, and enhanced customer satisfaction.

Smart meters and AMI have been gaining traction and some utilities are finding that the benefits of this technology substantially exceed the costs, even when not combined with other cost-effective technologies. In addition to its cost-effectiveness, an integrated AMI can provide the foundation for deploying other distributed energy technologies, such as PV and energy storage, in a way that supports utility operational needs.

RSIP Eligibility in the ISO-NE Forward Capacity Market

In addition to the costs and benefits discussed previously, Cadmus examined the feasibility of an additional revenue stream associated with bidding the RSIP generation into the ISO New England Forward Capacity Market. As summarized in a memorandum to the Green Bank, and appended to this report in Appendix A, the current rules for the Forward Capacity Auction preclude participation by the RSIP portfolio of projects, primarily due to the minimum 100 kW generating capacity requirement for each participating site.[88] In addition, the non-dispatchable nature of solar PV generation, inability to participate in both the capacity and energy market, and the seasonal peak period delivery requirements make participation even more problematic.

In order for the RSIP portfolio to participate in the FCA process, there would have to be a significant shift in current ISO-NE policies to accommodate distributed non-dispatchable generation assets in the capacity market. These issues are further discussed in Appendix A.

Data Availability and Ongoing Tracking

We understand that the Green Bank may benefit from tracking some cost-effectiveness elements on an ongoing basis. While performing the detailed calculations used for this report is likely unnecessary for regular tracking purposes, the Green Bank collects substantial amounts of data from PowerClerk, and other sources, that could facilitate a simplified ongoing cost-effectiveness metric. Key data collected and reported regularly under the existing program includes:

- Nameplate capacity
- Expected electricity generation
- Incentive cost

Based on our analysis, these regularly tracked numbers, with some conversion factors to account for additional costs and benefits, could be used to approximate ongoing cost-effectiveness from at least the program administrator perspective.

Calculating Approximate Benefits

The primary benefits that accrue to the Green Bank are based on avoided energy and avoided capacity costs. Both of these metrics can be approximated based on the expected generation and nameplate capacity reported through the Green Bank's PowerClerk system:

[88] The average solar PV system size is 7.44 kW for the full RSIP dataset used in this study.

- **Energy Benefits:** PowerClerk includes a field for expected annual energy generation for each PV project. The sum of these results can be multiplied by a 25-year lifetime to approximate lifetime generation.[89] This lifetime generation can be used directly for calculating the objective function or can be multiplied by an up to date avoided cost of energy to be used in a PACT calculation. Updated cost of energy numbers can be obtained from the Avoided Cost of Energy Supply in New England report series, as was done for this evaluation.
- **Capacity Benefits:** Based on the load shapes analyzed for this evaluation, every MW of DC capacity added contributes approximately 330 kW of AC capacity savings based on peak demand periods. At an avoided capacity cost of $73.42/kW, this avoided capacity can be converted into a basic financial indicator.

In both cases, the value assigned to these benefits may change over time. For an approximate calculation, we recommend reviewing the avoided energy and capacity costs on, at least, an annual basis to ensure the correct values are being used. As noted previously, the energy benefits are expected to escalate each year by 2.23%, and capacity benefits by 1.9% and 13.15% for T&D and generation,[90] respectively, while the incentive costs continue to decline.

Calculating Approximate Costs

Compared to the incentive payments, which the Green Bank carefully tracks, the administrative costs of the program are modest, typically in the range of 5% to 6%. To estimate approximate total program costs, the Green Bank could simply multiply incentive payments by 1.06 to account for additional administrative costs. Depending on the availability of administrative budgets and accounting information, other alternatives are possible. Also, as incentive amounts decrease and administrative costs remain relatively fixed, the percentage will likely increase over time. However, so long as the total program budget remains similar, this assumed administrative cost adder is likely sufficient for general program tracking purposes.

Potential Metrics

Based on these approximate benefits and costs, the Green Bank could calculate a modified objective function using the following equation:

$$OF_M = \frac{Lifetime\ Generation}{1.06 * Incentive\ Payments}$$

[89] Note that we are disregarding performance degradation for simplicity.
[90] Escalation rates are nominal, unless otherwise noted.

Alternatively, the Green Bank could also track a simplified approximation of the PACT with the following equation:[91]

$$PACT_M = \frac{Lifetime\ Generation * avoided\ energy\ cost + nameplate\ capacity * 0.33 * avoided\ capacity\ cost}{1.06 * Incentive\ Payments}$$

We do recommend that the Green Bank also track Cost of Conserved Energy (CCE). This measure is very similar to the OF, but is more comparable to what utilities track for energy efficiency program cost effectiveness. It also provides an easy way to assess overall simplified cost effectiveness through comparison to the avoided cost of energy. For example, the average avoided cost for a power plant may be 5 cents per kWh per year. If the equation below for solar or energy efficiency produces a CCE of 4 cents, then they are economically superior options to the power plant. CCE may also be used to compare options with different initial cost, lives, and savings as they all can be summarized and compared based on their CCE. CCE can be estimated using either TRC or PACT costs as follows:

$$\frac{initial\ cost * CRF}{savings}$$

Where CRF is the capital recovery factor[92] that can be computed using Excel or any financial calculator and automated to work with the Green Bank's existing data exports. CCE is expressed as cents per kWh per year (either generated through a renewable option or saved through an energy efficiency program). Initial cost includes administration and incentive cost for PACT. For TRC, they include customer contribution.

[91] The value 0.33 in the equation comes from the report section "Peak Period Output of Residential PV Systems."

[92]

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Appendix A. Memorandum Regarding FCA Eligibility

To:	Connecticut Green Bank
From:	Birud Jhaveri, Shawn Shaw
RE:	Eligibility of RSIP Assets to Participate in ISO-NE Forward Capacity Market
Date:	September 18, 2015

As requested by the Connecticut Green Bank (CGB), Cadmus has investigated the feasibility of including residential solar photovoltaic (PV) assets in ISO-New England's (ISO-NE) Forward Capacity Auction (FCA). While we have attempted to ensure the accuracy of this memo, integrating renewables in the Forward Capacity Market (FCM) continues to evolve through changing regulations. Should any discrepancy arise between the information provided herein and ISO-NE's Market Rule 1[1], Market Rule 1 should be relied upon. Additionally, this memo summarizes select minimum criteria for CGB's participation in the FCA; it does not attempt to provide a complete FCM qualification guideline.[2]

By the end of 2014, the New England region had achieved 900 MW of solar PV resources (AC nameplate capacity) and the ISO-NE's solar PV forecast projects the region will realize nearly 2,500 MW by 2024.[3] Nevertheless, based on our assessment, we find CGB's current residential portfolio disqualified from participating in an ISO-NE FCA. We also find it to be disadvantageous for the CGB to aggregate any newly installed solar PV resources and participate in an ISO-NE FCA in the foreseeable future based on current market rules. Solar PV resources, particularly small aggregated systems, face significant barriers to effectively participate in Forward Capacity Auctions. This is highlighted by the fact that only 1.2 MW of distributed solar PV has cleared in the FCA.[4] This memo provides a background on the capacity and energy markets, abbreviated participation requirements, and other considerations leading to our conclusion.

Capacity and Energy Market Background

The capacity market is a forward market intended to ensure New England has adequate resources to meet all electricity demand plus reserve requirements three years into the future. Beginning in June 2018, capacity payments will be based on an individual resource's (or aggregated resources in the case of Demand Resources) performance during scarcity conditions (times when the system is unable to meet its energy or reserve requirements). The capacity market fulfills two primary objectives: ensuring resource adequacy and providing appropriate incentives for resource performance. The ISO obtains the resources needed through annual forward capacity auctions; bidders will price their offers in the

[1] http://iso-ne.com/participate/rules-procedures/tariff/market-rule-1
[2] ISO-NE now provides a simplified FCM Participation guide to assist market participants in understanding participation in the FCM. The simplified guide should be consulted in combination with Market Rule 1, Market Manuals, Operating Procedures and Planning Procedures. The simplified guide can be found at http://iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide.
[3] Final 2015 PV Forecast, April 2015; http://www.iso-ne.com/static-assets/documents/2015/05/final_2015_pv_forecast.pdf
[4] ISO-NE FCA Auction Results filings

capacity market based on the expected net energy market revenues earned in the capacity delivery period. The two markets, FCM and the Energy Market are linked; market participants receive their total revenue requirement through the combination of revenues earned in the capacity and energy markets.

Participation in the FCA for existing CGB solar assets

The existing market rules provide four options for capacity resources to participate in the FCA. Resources can either qualify as a New or Existing 'Generating Capacity Resource' or a New or Existing 'Demand Resource'. In order to qualify as a Generating Capacity Resource, each resource site (i.e. not in aggregate) must have a minimum alternating current output size (i.e. not nameplate capacity) of 100 kW.[5] Qualifying as a Demand Resource requires the capacity offered to be a minimum of 100 kW aggregated output within an ISO predefined local Dispatch Zone and a nameplate rating less than 5 MW or a nameplate rating less than the non-coincident peak load at the facility for the prior 12 months, whichever is greater.[6] With individual sites in the CGB residential solar program unable to meet the minimum capacity output threshold deemed necessary for registering as a Generating Capacity, participating as a Demand Resource becomes the only viable option for the CGB solar portfolio to partake in the FCA.

Demand Resource is defined by the ISO to include energy efficiency, distributed generation and load management.[7] Demand Resources are further categorized into two categories – passive and active. Passive Demand Resources include capacity resources that are non-dispatchable (e.g. solar photovoltaic). Since the CGB solar portfolio has not previously been registered with the ISO to fulfill a Capacity Supply Obligation, by clearing in a past FCA, the portfolio capacity must be registered as New Passive Demand Resource.

The ISO defines New Demand Resource as a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the FCA, or distributed generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure or public service emergencies during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the FCA.[8] As the next applicable Existing Capacity Qualification Deadline is for FCA #11 on June 6, 2016 for the 2020-2021 FCM, and since none of the CGB portfolio resources are utilized to solely address power outage events, the market rules disallow any capacity that has been in service prior to June 6, 2016 to participate in FCA #11, disqualifying all of CGB's current portfolio assets.

Considerations for participation in the FCA for new CGB solar assets

The CGB does have the option to attempt to qualify new capacity, with an in-service date after June 6, 2016 and with a minimum of 100 kW aggregated output, in FCA #11 for the 2020-2021 FCM. FCA #11

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[5] ISO-NE Market Rule 1 Section III.13.1

[6] ISO-NE Market Rule 1 Section III.13.4.1; ISO-NE Presentation: Distributed Generation/PV in the Forward Capacity Market, September 15, 2014

[7] ISO-NE Presentation: Distributed Generation/PV in the Forward Capacity Market, September 15, 2014

[8] ISO-NE Market Rule 1 Section III.13.1.4.1.2

will take place on February 6, 2017. In order to qualify any new capacity, CGB must submit a Show of Interest filing by March 8, 2016 and a completed qualification package by June 21, 2016.[9] There are, however, at least two more considerations that hinder participation in the FCA. First, all Demand Resources are required to commit capacity during both summer peak and winter peak periods as well as during supply scarcity events. Second, while Passive Demand Resources are able to earn revenues through the capacity market, they are ineligible to earn revenues through the energy market as these resources are non-dispatchable.

Passive Demand Resource can be categorized as On-Peak or Seasonal Peak and are required to perform during specified performance hours, in the applicable seasonal performance months. The table below displays the performance requirements[10]:

Resource Type	Performance Months	Days	Performance Hours
On-Peak	Summer: June, July, August Winter: December, January	Mon-Fri, non-holidays	Summer: 14:00-17:00 Winter: 18:00-19:00
Seasonal Peak	Summer: June, July, August Winter: December, January	Mon-Fri, non-holidays	Hours where load is ≥ 90% of the most recent 50/50 system peak load

Since solar PV resources would be unable to perform during the winter performance hours or during possible winter peak events in the evening hours, it would be subject to performance penalties related to non-performance during those hours. While this issue was the subject of a recent FERC docket[11], the Commission ordered that energy efficiency resources be exempt from such non-performance penalties, although making no such exceptions for other non-dispatchable demand resources. Application of such performance penalties would be economically disadvantageous to CGB. Calculation of the penalties is formulaic and based on hourly real-time locational marginal prices (LMPs), capacity zone and other factors.[12] Penalty for a single shortage event can be excessive as LMPs often spike during peak system and/or scarcity events. Penalties are assessed by the hour with a maximum daily penalty of 10% of the resource's annualized FCA revenues for that Capacity Commitment Period.[13] Accumulation of the hourly penalties can wipe away a resource's entire annualized FCA revenues, leaving the market participant with no revenues and significant out-of-pocket participation expenses.

The ISO market rules do provide an option to submit a composite offer by participating in the FCA with other resource types (e.g. wind, CHP, gas). However, in the summer period only one resource type can be used to supply the amount of capacity offered during the entire summer period; the winter period would allow multiple resource types to combine to supply the amount of capacity offered.[14] The winter

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[9] ISO-NE Master Forward Capacity Auction #11 Schedule, revised 8/6/2015

[10] ISO-NE Presentation: Distributed Generation/PV in the Forward Capacity Market, September 15, 2014

[11] FERC Docket ER14-1050-000

[12] Market Rule 1 Section III.13.7.2.7.1.2

[13] Market Rule 1 Section III.13.7.2.7.1.3

[14] Market Rule 1 Section III.13.1.5(a)

resource in such arrangements would have to forgo participation in summer months, thereby reducing its revenues.

While non-dispatchable demand resources that participate in the FCM are eligible to receive capacity payments, they are unable to earn payments through the energy market, reducing the revenue stream for such resources. This may change based on a Supreme Court ruling on FERC Order 745 in the future. Nevertheless, the current compensation model, coupled with non-performance penalties, significantly reduces any economic gain for CGB from participating in the ISO markets. In order to assess the profitability of such an endeavor, Cadmus would need to model the penalty liability based on historical shortage events for Seasonal Peak Passive Demand Resources and/or model a composite offer under an On-Peak Demand Resource scenario. Unfortunately, this modeling is outside the scope of our current efforts and may not be justified based on the general findings noted above.

While the vast majority of installed or forecasted distributed solar PV resources do not currently participate in the ISO-NE FCA, these resources do impact ISO-NE's Installed Capacity Requirement (ICR)[15] by informally reducing the load forecast below levels that would have otherwise been required without the resources. Formal consideration of the resources in the ICR can be realized to the extent they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements.[16] Additionally, ISO-NE's Distributed Generation Forecasting Working Group[17] is currently developing and formalizing forecasts that project the anticipated growth and impact of distributed generation resources on New England's power system. This DG forecast is regularly updated and is used in long-range planning activities, such as transmission planning and resource adequacy.

[15] Installed Capacity Requirement (ICR) is a measure of the installed resources that are projected to be necessary to meet the peak demand forecast and reserve requirement by both ISO-NE and the Northeast Power Coordination Council's.

[16] ISO-NE Market Rule 1 Section III.12.8

[17] ISO-NE Distribution Generation Forecasting Working Group is a regional forum for interested parties, including policymakers, DG program administrators and distribution companies to provide input on ISO-NE's long-term DG forecast.