# Task 1 Report:Evaluation of Current SolarCosts and Needed IncentiveLevels Across Market Segments

Prepared for the Massachusetts Department of Energy Resources



By Sustainable Energy Advantage, LLC In association with Meister Consultants Group, La Capra Associates, and Cadmus

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# About the Massachusetts Department of Energy Resources (DOER)

DOER's Mission is to create a cleaner energy future for the Commonwealth, economically and environmentally, including:

- Achieving all cost-effective energy efficiencies;
- Maximizing development of cleaner energy resources;
- Creating and leading implementation of energy strategies to ensure reliable supplies and improve relative costs; and
- Support clean tech companies and spurring clean energy employment.

DOER is an agency of the Massachusetts Executive Office of Energy and Environmental Affairs (EEA).

#### About this Report

The Team completed our Evaluation of Current Solar Costs and Needed Incentive Levels across Market Segments (Task 1 Report) in support of the DOER's Solar Policy Program and post 400-MW policy analysis under a competitive contract awarded to Cadmus.

As part of the effort, The Cadmus Group, La Capra Associates, Meister Consultants Group, and Sustainable Energy Advantage developed five companion reports:

Task 1: Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors
Task 2: Comparative Evaluation of Carve-out Policy with Other Policy Alternatives,
Task 3a: Evaluation of the 400 MW Solar Carve-out Program's Success in Meeting Objectives
Task 3b: Analysis of Economic Costs and Benefits of Solar Program, and
Task 4: Comparative Regional Economic Impacts of Solar Ownership/ Financing Alternatives.

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# 1 Introduction

The Massachusetts Department of Energy Resources (DOER) commissioned a consulting team consisting of Cadmus (Prime Contractor), Sustainable Energy Advantage, LLC (Project Manager), Meister Consultants Group, and La Capra Associates (collectively known as the Consulting Team) to provide an analysis of Massachusetts solar photovoltaic (PV) cost trends and projections, including costs for PV modules and total installed costs. Three market segments were assessed:

- 1. Residential roof-mounted systems (<15 kW)
- 2. Commercial roof-mounted systems (15-500 kW)
- 3. Large-scale ground-mounted systems (500-6,000 kW)

The purpose of this analysis was to use a solar financing model to establish the 10-year levelized incentive (\$/MWh) in each market segment, under a range of future conditions, that allows system owners to achieve their target economic rate of return, thereby enabling market penetration sufficient to achieve the Commonwealth's solar policy objectives. This 10-year levelized incentive level is not synonymous with a Solar Renewable Energy Credit (SREC) price floor akin to that used in the Renewable Portfolio Standard (RPS) Class I Solar Carve-out policy structure supporting the first 400 MW of the solar carve-out.<sup>1</sup> However, DOER can use the results of this analysis to develop SREC floor and Alternative Compliance Payment (ACP) rates, as well as adjusted SREC Factors, for setting incentives for expanding the Commonwealth's solar PV installations to a target of 1,600 MW by 2020.

The Consulting Team considered several ownership and financing options in order to test the sensitivity of the required incentive to changes in capital structure and cost of capital. We also tested the sensitivity of results to the differing rates across major utility service territories, and to future net metering policy.

# 2 Summary of Modeling Parameters and Results

In addition to the three market segments identified above, the Consulting Team developed projections of required incentives for a variety of circumstances, including:

- Three different future installed cost trajectories encompassing the mean costs, plus or minus one standard deviation, in each market segment;
- Ground-mounted systems (500-6,000 kW) installed on capped landfills;
- A representative sampling of different utility territories and rate classes;
- Two net metering futures, including (i) A **NM-No Cap** case, which assumes that the current net metering policy caps as a percent of load are eliminated, so that current net metering benefits are assumed to be available for the entire study period; and (ii) a **NM-Cap** case in which the current statutory net metering caps apply, and are assumed to be reached such that the sunset of the current net metering policy is effective December 31, 2014, resulting in either a

<sup>&</sup>lt;sup>1</sup> Under that policy structure, project owners anticipate a revenue stream of some number of years of market surplus, with revenue influenced by the floor price and the remainder of the SREC life under SREC shortage (with market revenue influenced by the alternative compliance payment (ACP)). Therefore, the fixed incentive results presented herein are expected to be higher than the floor prices needed to support installations under the SREC market structure used for the first 400 MW policy, *if* the ACP is set at a level sufficiently above the auction price floor.

portion of (for projects 15-500 kW) or all of (for projects 500-6,000 kW) electricity revenues being derived from the wholesale market thereafter; and

• Private third-party ownership, project host ownership, and public-sector ownership; for the third-party ownership scenario, an assumed reduction in the cost of equity after the expiration of the federal investment tax credit (ITC) as a result of an increase in the availability of capital to solar project finance.

The Team selected the most meaningful combinations of the above variations to provide insight on incentives required by different market segments under different circumstances. In total, we modeled 84 different cases for installation years 2013 through 2020, for each of three different ownership scenarios, for a total of 252 different incentive forecasts.

The case parameters described above are summarized in Table 1. For incentive modeling, the Consulting Team arranged these factors into the 252 distinct case combinations in order to establish the range of potential incentives necessary to achieve the Commonwealth's solar policy objectives.

Market Segment	Revenue Sources	Revenue Allocation	ITC	Ownership	Power Purchase Agreement	Installed Cost Trend	Net Metering Availability	Utility Service Territory
Roof < 15 kW	Net metering credits, by utility and rate code	100% net metering for all segments	For residential, expires after 2016	Private third-party ownership, equity & debt	(PPA) Third-party model assumes PPA offered at a discount to net metering credits	Mid-cost trajectory (base cost case)	No cap (NM-No Cap)	Mass Electric (National Grid)
Roof 15–500 kW	Wholesale electricity sales	For 15- 500 kW, also run with 50% net metering and 50% wholesale sales	For commercial, reduced to 10% after 2016	Host ownership, equity, and debt	Other ownership models assume no discount to net metering credits	Low-cost trajectory (low cost case)	Capped according to current statute (NM-Cap)	WMECO
Ground 500–6,000 kW		For 500- 6,000 kW, also run with 100% wholesale sales		Public ownership, municipal bond financed		High-cost trajectory (high cost case)		Boston Edison (NSTAR)
Landfill 500–6,000 kW								Commonwealth Electric (NSTAR)

#### Table 1: Summary of Modeling Parameters\*

\* Each column represents the modeling options within a single parameter. The table should **NOT** be read from left to right assuming that each row represents the full range of modeling scenarios.

### 2.1 PV Installed Cost Trends

The team based projections on current market conditions and published national cost trajectories. Two cost trend methods were evaluated, each resulting in three costs trend scenarios for each of the market segment categories. We used a hybrid of the mean installed cost trending method and the standard deviation trending method (both described in Section 4.2.2) to derive low, base, and high installed cost case incentive results in this analysis. Figure 1, Figure 2, and Figure 3 summarize the PV installed cost trends used in this analysis. The bold lines are the final hybrid trajectories, while dashed lines are trends from the mean installed cost trending method and the standard deviation trending method.



Figure 1: Residential <15 kW PV System Installed Costs 2008 – 2020 (\$/kW, nominal)



Figure 3: Large-Scale Solar 500-6,000 kW PV System Installed Costs 2010-2020 (\$/kW, nominal)



#### 2.2 Revenue Requirements and Incentive Calculations

Figure 4 through Figure 7 summarize the estimated 10-year levelized incentive payment stream necessary for each market segment to cover its costs and deliver the assumed target rate of return to project investors under the base case cost trajectory, third-party private ownership scenario, and assuming that net metering benefits continue throughout the study period (NM-No Cap). The base case is not synonymous with best guess scenario: it represents the mean historic installed cost (adjusted as described in Section 4.2.1) for each market segment, trended at the mid-cost

trajectory. To this end, policymakers should carefully consider all of the case results to determine which best align with policy objectives.

The values shown in the figures presented in this report are for illustrative rate classes in each of the four major investor-owned utility (IOU) service territories, and apply to projects entering commercial operation in the year specified. Individual projects are expected to require incentives in a range above and below the trends, as discussed further below. The forecasted incentives are shown in \$/MWh. A one standard deviation bandwidth only brackets roughly 68% of the installations for a normal probability distribution.

It is important to remember that the modeling assumptions and results in this analysis are intended to help support informed decision making, and are not intended to prescribe incentive rates directly. Policymakers will need to interpret these results in the context in which the data are made available, as well as the context of their policy objectives, which influence incentive design.

# Figure 4: Incentive Requirement: Roof Mounted <15 kW Residential (Base Cost Case, NM-No Cap, Private Third-Party Ownership)



For roof-mounted projects below 15 kW, which are assumed to be residential applications financed by the homeowner, a state tax credit equal to the lesser of 15% of total eligible costs or \$1,000 is assumed available in the host ownership case. The results of this design are shown in Figure 5.

# Figure 5: Incentive Requirement: Roof Mounted <15 kW Residential (Base Cost Case, NM-No Cap, Host Ownership, with State Tax Credit)



Figure 6: Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case, NM-No Cap, Private Third-Party Ownership)







The complete series of results for the other ownership scenarios and installed cost trajectories, as well as for groundmounted installations on landfills and the NM-Cap net metering scenario, are shown in Appendix D. In the following figures, illustrative results for each of these variations are shown.

Figure 8 through Figure 10 show, for each market segment,<sup>2</sup> the sensitivity of the results shown above to different ownership structures, comparing private third-party ownership to private host ownership and public ownership under base cost case assumptions for an illustrative utility – in this case Massachusetts Electric (National Grid). Note that the public ownership case is not sensitive to the expiration of the ITC, as the tax credit is only assumed to be available to private tax-paying investors or owners.

<sup>&</sup>lt;sup>2</sup> Public ownership was not analyzed for the <15 kW segment.



Figure 8: Incentive Requirement: Sensitivity of Roof Mounted <15 kW Residential to Ownership Structure







Figure 10: Incentive Requirement: Sensitivity of Ground Mounted 500-6,000 kW to Ownership Structure

Figure 11 through Figure 13 show, for each market segment, the sensitivity of results to different cost variations (bracketing plus or minus one standard deviation) and trends, comparing the high, base, and low cost cases under the NM-No Cap and private third-party ownership assumptions for an illustrative utility (Mass Electric).



Figure 11: Incentive Requirement: Installed Cost Sensitivity Analysis: Roof Mounted <15 kW Residential, 3rd-Party Private Ownership





Figure 13: Incentive Requirement: Installed Cost Sensitivity Analysis: Ground Mounted 500-6,000 kW, 3rd-Party Private Ownership



Figure 14 and Figure 15 show, for the 15-500 kW and 500-6,000 kW market segments, the sensitivity of results to future potential net metering policy, comparing the NM-Cap and NM-No Cap scenarios under the base case cost trajectory and private third-party ownership for an illustrative utility (Mass Electric). No sensitivity is shown for roof mounted projects

<15 kW without net metering benefits, because production from these facilities is always assumed to be consumed behind the meter.

#### Figure 14: Incentive Requirement: Sensitivity of Roof Mounted 15-500 kW to Net Metering Policy, 3rd-Party Private Ownership



Figure 15: Incentive Requirement: Sensitivity of Ground Mounted 500-6,000 kW to Net Metering Policy, 3rd-Party Private Ownership



Finally, Figure 16 shows the sensitivity of required incentives to large ground-mounted systems placed on landfills, comparing the landfill versus greenfield incentive projections under base base costs, NM-No Cap, and private third-party ownership for an illustrative utility (Mass Electric).





# 3 Approach

# 3.1 Levelized Cost of Energy Modeling (Cost of Renewable Energy Spreadsheet Tool)

The Consulting Team developed levelized cost of energy (LCOE) projections using the National Renewable Energy Laboratory's (NREL) *Cost of Renewable Energy Spreadsheet Tool* (CREST) as the solar model. The CREST model and supporting documentation, which were developed by Sustainable Energy Advantage, LLC, are available from the NREL website.<sup>3</sup> CREST is a publicly available and transparent tool that aids policymakers with estimating renewable energy costs for various public policy purposes, such as establishing cost-based or performance-based incentives.

The model is designed to calculate the cost of energy, or minimum revenue per unit of production needed, for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return. For this analysis, the Team modified the model output to provide a 10-year levelized incentive requirement rather than a 25-year levelized cost of energy.

<sup>&</sup>lt;sup>3</sup> <u>https://financere.nrel.gov/finance/content/crest-cost-energy-models</u>

# 3.2 Calculating 10-Year Levelized Incentive Requirements

The CREST model is used to solve for the 10-year levelized incentive required to satisfy all expenses and meet investors' return aspirations for each project category. In addition to the standard cost, performance, and financing inputs that would be used to calculate a LCOE, the model also incorporates the market value of net metering credits<sup>4</sup> and/or wholesale sales generated beginning with the first year of operation, as well as assumed Class 1 Renewable Energy Credit (REC) revenue from years 11 through 25. The inclusion of this market value of production means that CREST solves for the minimum *additional* revenue required to achieve the specified project's defined after tax return on invested capital. In other words, the model calculates the required 10-year levelized incentive directly, not as an intermediary step.

# 3.3 Policy Structure Assumptions

The Consulting Team based this analysis on a policy structure similar to the policy programs already in place that are applicable to the first 400 MW of Class I Solar Carve-out. The new policy would be an additional Solar Carve-out, separate from the first 400 MW target, and would include the following key features:

- A formula-adjusted demand target that must be met annually by load-serving entities;
- Specified alternative compliance payments serving as a cost cap;
- A fixed duration of SREC auction eligibility (e.g., 10 years) followed by SREC eligibility until the final auction and Class I REC eligibility for the remainder of the project life; and
- A SREC opt-in clearinghouse fixed-price auction *without* any entity guaranteed to purchase SRECs unsold in the auction (herein referred to as a *soft* floor). As there is no guarantee that the price will not fall below the floor, the clearinghouse auction may not provide SREC revenue until a few years after production. Also, because under the present policy market prices have fallen below the floor, project investors are likely to discount the floor price in their revenue projections.<sup>5</sup>

The new policy is also assumed to provide *differentiated* support to different installation types, considering both the incentive needed for the installation type as well as DOER's relative preference for supporting the installation type. A more aggressive (higher) incentive relative to the average required incentive would be expected to stimulate more investment than a more conservative (lower) incentive. This differentiation is assumed to be accomplished through the combination of universal SREC auction floor price and ACP, with a fraction of SRECs issued per MWh generated (referred to as the **SREC Factor**) that is differentiated for different installation types.

# 3.4 Setting Incentive Parameters

Since policy structure and policy objectives influence incentive design, the incentive-setting process is not based solely on an estimate of the 10-year levelized incentive necessary to achieve an assumed target rate of return. Rather, DOER would set the incentive parameters, consisting of the annually declining ACP and price floor, and the SREC Factor for

<sup>&</sup>lt;sup>4</sup> Net Metering Credits are also used as a proxy for the value of production consumed behind the meter. See section 4.4.1.1 for a more detailed description.

<sup>&</sup>lt;sup>5</sup> Discounting may result from a few situations. Issuance of reminted SRECs through the auction for SRECs that fail to clear imposes a delay when a project received revenues. So if an investor assumed that SRECs going into the auction might result in a two-year delay in revenue on average, it might discount the value by two years at its cost of capital. Further discounting might result from the risk that SRECs are not bought out of the auction or reminted for any number of reasons, including the risk that costs may drop such that revenue required for future installations falls below the level of the floor.

each installation type. Establishing these incentive parameters for making their financial projections requires that DOER make:

- Decisions, such as how aggressive or conservative the incentive should be relative to the range of 10-year incentive requirements calculated for each market segment based on potential future cost trajectories, ownership options, and financing costs; and
- Assumptions regarding how market participants view the policy landscape, including the degree to which investors discount the price floor (during times of surplus) and the ACP (during times of shortage), the proportion of the 10-year SREC period influenced by shortage or surplus, and the Class I REC revenue after the 10 year SREC period.

To accomplish these decisions and assumptions, DOER can convert the 10-year revenue requirement projections summarized herein to DOER's selected SREC Factor via the following transformative steps:

- Select the results of the applicable 10-year levelized inventive for an installation type of interest, or convert the results of this report to a desired 10-year levelized incentive based on the aggressive-conservative decision and other policy choices, such as the degree of differentiation between installation types.<sup>6</sup>
- 2. Convert a declining schedule of ACP and Auction Floor prices to a constant equivalent levelized schedule for each using an appropriate nominal discount rate.
- 3. Make assumptions for the following parameters and market expectations to solve for an installation-type specific average expected revenue per SREC generated, as follows:

#### Expected Avg. Revenue/SREC = Equivalent Constant Auction Price \* $(1-d_f) * Y_A$ + Equivalent Constant ACP Rate \* $(1-d_{ACP}) * Y_{ACP}$

where:		
	Equivalent Constant Auction Price =	Levelized value of declining Auction Floor Price schedule based on assumed discount rate (\$/SREC)
	Equivalent Constant ACP Price =	Levelized value of declining Alternative Compliance Payment schedule based on assumed discount rate (\$/SREC)
	d <sub>ACP</sub> =	Assumed market discount to ACP in shortage years (%)
	Y <sub>ACP</sub> =	Assumed market percent of 10 SREC period years (randomly distributed) with market expected to be short (relying on ACPs)
	d <sub>f</sub> =	Assumed market discount to soft floor (%)
	Y <sub>A</sub> =	Assumed market percent of 10 SREC period years (randomly distributed) with adequate supply (with SREC sellers relying on auction revenue)

<sup>&</sup>lt;sup>6</sup> As an example, if DOER does not wish to differentiate incentives between utility territories or ownership types, it would select a position within the range of these results.

4. Determine the SREC Factor needed to provide the desired 10-year levelized revenue for the selected installation type (from step 1) by dividing by the value for Expected Avg. Revenue/MWh (from step 3), as follows:

#### SREC Factor (SREC/MWh) = 10-year Incentive Requirement (\$/MWh) / Expected Avg. Revenueper SREC (\$/SREC)

The policy decisions and assumptions in each of these steps are to be made by DOER and are beyond the scope of this report.

# 4 Key Assumptions

# 4.1 Project Categories

The Consulting Team forecasted levelized costs and market revenues across several project categories in order to gain insight into the potential range of incentives that may be necessary to foster the development of a diversified market. Using available industry and market research data, we developed unique cost, revenue, and financing assumptions for each of these categories. The market segments are described in greater detail below.

#### 4.1.1 Market Segment Classifications: Size and Installation Type

Table 2 lists four project market segment classifications based on the size and installation type. The Team developed base, low, and high installed cost assumptions for each category. While these market segments do not encompass all possible installation types, combined they represent most of the Massachusetts solar marketplace.

Market Segment	Installation Type/ Land Classification	Project Size Range (kW)	Representative Size for Modeling Purposes (kW)
Residential	Roof	< 15	5
Commercial	Roof/Ground	15 - 500	250
Large-Scale Ground	Ground (Greenfield)	500 – 6,000	1,500
Mounted	Landfill	500 – 6,000	1,500

#### Table 2: Project Categories by Market Segment, Defined by Size and Installation Type

#### 4.1.2 Ownership Structure

The Consulting Team tested the incentives required for each of the categories defined in Table 2 under at least two different ownership structures: private third-party ownership and host ownership. The Team also tested nonresidential categories under a public ownership option, in which we assumed that the project was financed through a 20-year municipal general obligation bond. Further details, including financing assumptions, are included in section 4.2.4.

#### 4.1.3 Items Not Considered

The Team chose the project categories described above in consultation with DOER, based both on market development trends to date and on the availability of installed cost data. The project categories (by size and type) are summarized in

section 4.1.1. Other parameters that were not considered include projects with single- or dual-axis tracking and ground-mounted projects smaller than 500 kW.

For the analysis, the Team also only considered projects interconnecting in one of the four major IOU territories in Massachusetts. A project interconnecting through Fitchburg Gas & Electric, or a municipal light plant, for example, might have a different revenue forecast. These types of projects would require case-by-case analysis, which falls outside the scope of this task. Furthermore, we used standard residential and small commercial rate codes to calculate net metering credit values; other retail rate classes may apply in certain cases, but were not considered in this analysis. Finally, while it is possible that certain conditions would yield avoided kW-based demand charges, these conditions would vary widely by installation and month. For this reason, we assumed that demand charges were not to be avoided.

#### 4.2 Costs

The Consulting Team developed PV system cost trends for each year of the analysis period. We based projections on current market conditions and published national cost trajectories, which we developed for each of the system type categories.

#### 4.2.1 Current Average System Costs

The Team developed current market prices for each size category based on installer-reported costs from the DOER SREC database.<sup>7</sup> We developed an average system cost for the first quarter of 2013 for the residential system size class. Review of this dataset suggested several irregularities that significantly increased the mean estimated system cost for this classification. Self-reported system costs for two of the largest residential installers in the dataset were significantly above the costs reported by other firms. Additionally, these installers reported the same \$/kW installed costs for all systems included in the data set. As a result, the Consulting Team deemed self-reported data from these installers as questionable and removed them from the dataset. We then used the revised dataset to estimate current market installed costs in Massachusetts. Figure 17 and Figure 18 shows the frequency distributions of residential system costs for both the raw and adjusted datasets.

<sup>&</sup>lt;sup>7</sup> <u>http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-</u>carve-out-program.html

#### Figure 17: Q1 2013 Residential System Installed Cost Frequency Distribution (unadjusted data; \$/kW)





The Team calculated a new average system cost for residential systems based on this adjusted data. Table 3 outlines the descriptive statistics for residential systems for both the adjusted and unadjusted datasets. The mean value was the basis for this analysis. Alongside this assumption, it is important to consider the potential impact of federal incentives on the way solar installed costs have been reported over the past several years. Since the ITC and cash payment in lieu thereof are cost-based, there might have been a tendency for developers to overstate (or at least aggressively interpret) the total costs eligible for federal incentives. If this is the case, the costs reported in the databases we used in this analysis would overstate the actual installed cost of solar during this time period. There is little in the way of public data, however, to confirm or quantify this possible effect.

	Unadjusted Data	Adjusted Data
Number of Systems	588	341
Ave Size (kW)	5.79	6.04
Mean Price (\$/kW, nominal)	\$5.43	\$4.66
Standard Deviation (\$/kW, nominal)	\$1.24	\$0.88

#### Table 3: Q1 2013 Residential System Market Statistics

The Team also developed an average system cost for the 15-500 kW, non-residential system size class. Because of the limited number of installations in the DOER dataset for quarter 1 of 2013, we used data from both quarter 4 of 2012 and quarter 1 of 2013 to develop an average representing current market conditions.<sup>8</sup> As the frequency distribution of system costs in Figure 19 shows, no major anomalies were present in the 15-500 kW data that would warrant removing data.

<sup>&</sup>lt;sup>8</sup> The Consulting Team performed a T-test to determine whether the quarter 4 2012 and quarter 1 2013 dataset were statistically distinct. This test did not show any statistical difference between the mean price of systems installed in quarter 4 of 2012 and in quarter 1 of 2013, suggesting that combining these two quarters was a valid approach.

#### Figure 19: Q4 2012/Q1 2013 15-500 kW System Installed Cost Frequency Distribution (\$/kW)



Table 4 provides descriptive statistics for the 15-500 kW size classification for quarter 4 of 2012 and quarter 1 of 2013. We used the mean value as the basis for this analysis.

Number of Systems	62
Average System Size (kW)	183
Mean Installed Cost (\$/kW, nominal)	\$4.22
Installed Cost Standard Deviation (\$/kW, nominal)	\$1.23

#### Table 4: Q4 2012/Q1 2013 15-500 kW Market Statistics

Finally, the Team applied a similar approach to develop average system costs in the Massachusetts market for the 500-6,000 kW system size classification. As with the 15-500 kW dataset, only a limited number of systems were installed in the Commonwealth during quarter 1 of 2013, so we combined data from both quarter 4 of 2012 and quarter 1 of 2013 to develop a market average cost for the analysis. This dataset did not have any obvious outliers; however, we eliminated two installations using tracking technology, as they were not representative of the systems we modeled for this analysis. Figure 20 shows a frequency distribution of installed prices from quarter 4 of 2012 and quarter 1 of 2013.



Table 5 provides descriptive statistics for the over 500 kW data used in this analysis. The Team used mean system costs for this analysis.

Number of Systems	19
Average System Size (kW)	1,593
Mean Installed Cost (\$/kW, nominal)	\$ 3.44
Installed Cost Standard Dev (\$/kW, nominal)	\$ 0.61

#### Table 5: Q4 2012/Q1 2013 500+ kW Market Statistics

#### 4.2.2 Trends

The Consulting Team examined two methods to trend current market cost data: the mean installed cost trending method and the standard deviation trending method. We combined the results from these two methods to produce a range of potential future PV system installed costs that account for a wide potential variance in future market installed costs. These methods are described below.

#### Mean Installed Cost Trending Method

For the first trend analysis, we trended mean system costs for each size from 2013 to 2020 based on two installed cost trajectories developed by the U.S. Department of Energy (DOE) for the 2012 DOE SunShot Vision Study.<sup>9</sup> The lower-cost trajectory corresponded to the cost decline needed to meet the federal SunShot installed cost goals, and as such is an aspirational projection. This low-cost future trend assumed a roughly 11% annual installed cost decline. The higher-cost trajectory was based a reference case trajectory from the SunShot vision study. Mirroring the DOE study, we calculated separate trajectories for residential rooftop, commercial rooftop, and utility-scale systems.<sup>10</sup> Table 6 shows the high and low cost solar trajectories used in this analysis.

<sup>&</sup>lt;sup>9</sup> This report is available online: <u>http://www1.eere.energy.gov/solar/pdfs/47927.pdf</u>.

<sup>&</sup>lt;sup>10</sup> The Consulting Team converted the trajectories to nominal dollars using the US GDP deflator.

	Uti	lity Scale	Resident	ial Rooftop	Commercial Rooftop		
	SunShot	Reference	SunShot	Reference	SunShot	Reference	
	Goal	Case	Goal	Case	Goal	Case	
Nominal Annual Cost Decline	-11.4%	-2.9%	-11.4%	-2.9%	-11.4%	-2.2%	

#### Table 6: High and Low Solar PV Installed Cost Trajectories (non-interconnection cost portion).

For each of these trajectories, we trended the portion of the installed costs representing the assumed interconnection cost proportion of total installed costs at a different rate than the remainder of the installed cost. Anecdotal evidence from installers suggests that certain areas of the Massachusetts electrical grid are already experiencing interconnection issues (corresponding to expectations of higher interconnection costs) due to high concentrations of distributed generation facilities. Given the increase in solar installations anticipated during the next phase of the Commonwealth's solar incentive programs, distributed generation (DG) system interconnection costs could rise over the analysis period as more distribution system upgrades are required.

For each system size classification, the Consulting Team assumed that 4% of the installed costs represents the portion attributable to current interconnection costs. We assumed residential systems to have had interconnection cost that remained constant over the analysis period, while the larger system sizes would have a 5% annual increase in interconnection costs. For both the high and low costs scenarios, we added the trended interconnection costs and the trended non-interconnection costs to develop annual installed cost projections for each system classification. Table 7 and Table 8 illustrate this calculation for the residential, high-cost projection and the ground mounted 500-6,000 kW low-cost projection.

System Component	Annual Cost Decline	2013	2014	2015	2016	2017	2018	2019	2020	
Non-Interconnection	-3%	\$4.43	\$4.30	\$4.18	\$4.06	\$3.94	\$3.83	\$3.72	\$3.61	
Interconnection	0%	\$0.18	\$0.18	\$0.18	\$0.18	\$0.18	\$0.18	\$0.18	\$0.18	
<b>Total Projected System</b>	n Cost	\$4.61	\$4.48	\$4.36	\$4.24	\$4.12	\$4.01	\$3.90	\$3.79	

Table 7: Residential High-Cost Future Installed Cost Projections Calculation (\$/kW, nominal)

#### Table 8: Ground Mounted 500-6,000 kW Low-Cost Future Installed Cost Projections Calculation (\$/kW, nominal)

System Component	Annual Cost Decline	2013	2014	2015	2016	2017	2018	2019	2020
Non-interconnection	-11%	\$3.19	\$2.82	\$2.50	\$2.21	\$1.96	\$1.74	\$1.54	\$1.36
Interconnection	5%	\$0.13	\$0.14	\$0.15	\$0.15	\$0.16	\$0.17	\$0.18	\$0.19
Total Projected System Cost		\$3.32	\$2.96	\$2.65	\$2.36	\$2.12	\$1.91	\$1.72	\$1.55

We developed a third mid-cost trend to represent the average of the high- and low-cost trajectories. Figure 21 shows this method as applied to the residential system size classification.



Figure 21: Mean Installed Cost Trending Method Applied to Residential System Costs (\$/kW, nominal)

#### Standard Deviation Trending Method

The second trending method applied the annual percentage cost decline rate of the mid-cost trend as part of the mean installed cost trending exercise to (i) the mean system cost for each project size and to (ii) the mean plus and minus one standard deviation. This annual percentage cost decline rate was -6.5%, -5.5% and -5.9% for the <15 kW, 15-500 kW and 500-6,000 kW system size classes, respectively. Figure 22 illustrates this technique as applied to the residential system size classification.



Figure 22: Residential System Cost Trend from Standard Deviation Trending Method (\$/kW, nominal)

#### Hybrid Cost Trend

The Team developed hybrid trajectories by combining the outer bounds of the two cost trajectory methods described above. For each system size category, we used the maximum value in any year of the two high-cost trend values of the two calculated trajectories for the final high cost trend, and used the minimum value in any year of the two low-cost

trend values as the low-cost trajectory. The mid-cost trajectory was identical for both analysis techniques. Figure 23, Figure 24, and Figure 25 show the final hybrid cost trends we used for each system size classification, as well as the trajectories for both of the individual trending analyses. The bold lines show the final hybrid trajectories used in the analysis. The dashed lines are trends from the mean installed cost trending method and the standard deviation trending method.







Figure 24: 15-500 kW PV System Costs, 2010-2020 (\$/kW, nominal)





Table 9 provides the final projected annual installed costs for each system type and cost trajectory.

Size (kW)	Cost Trend	2013	2014	2015	2016	2017	2018	2019	2020
<15	High	\$5.43	\$5.09	\$4.78	\$4.48	\$4.21	\$4.01	\$3.90	\$3.80
	Base	\$4.54	\$4.26	\$3.97	\$3.71	\$3.48	\$3.26	\$3.07	\$2.89
	Low	\$3.66	\$3.43	\$3.22	\$3.02	\$2.82	\$2.52	\$2.25	\$2.01
	High	\$5.35	\$5.06	\$4.78	\$4.52	\$4.27	\$4.04	\$3.82	\$3.67
15-500	Base	\$4.13	\$3.87	\$3.63	\$3.42	\$3.24	\$3.07	\$2.92	\$2.78
	Low	\$2.90	\$2.74	\$2.59	\$2.45	\$2.31	\$2.19	\$2.07	\$1.89
500 6 000	High	\$3.97	\$3.74	\$3.52	\$3.31	\$3.12	\$2.99	\$2.92	\$2.85
500-6,000	Base	\$3.36	\$3.14	\$2.94	\$2.76	\$2.60	\$2.45	\$2.32	\$2.20
(greenneid)	Low	\$2.75	\$2.59	\$2.44	\$2.30	\$2.12	\$1.90	\$1.71	\$1.55

#### Table 9: Projected PV System Costs (S/kW, nominal)

The Team developed an additional cost projection for ground-mounted systems sited on landfills. We spoke with installers who indicated that landfill projects could reasonably be assumed to cost 115% of a traditional ground-mounted system. The installers noted that engineering and permitting costs increased landfill development costs. Additionally, the ballasted racking systems required on landfills are more expensive than other racking applications. Table 10 provides the landfill system costs trends we used in this analysis.

	Cost Trend	2013	2014	2015	2016	2017	2018	2019	2020	
500-6,000	High	\$4.57	\$4.30	\$4.04	\$3.81	\$3.58	\$3.44	\$3.36	\$3.28	
	Base	\$3.87	\$3.61	\$3.38	\$3.17	\$2.98	\$2.82	\$2.67	\$2.53	
(Lanann)	Low	\$3.17	\$2.98	\$2.80	\$2.64	\$2.44	\$2.19	\$1.97	\$1.78	

#### Table 10: Projected Landfill Sited System Cost (\$/kW, nominal)

#### 4.2.3 Federal Incentives ITC

The Consulting Team modeled applicable federal incentives currently in effect. For residential systems, we assumed that an ITC equal to 30% of qualifying costs is available for projects entering construction on or before December 31, 2016. We assumed that no ITC would be available for residential systems thereafter. For commercial systems, we assumed an available ITC at 30% through December 31, 2016, and at 10% thereafter.

The Team assumed that 96% of installed costs (other than those related to transmission and interconnection) were depreciated on the federal five-year Modified Accelerated Cost Recovery System (MACRS) schedule, 2% of installed costs were depreciated on the 15-year MACRS schedule, and 2% on the 20-year straight-line basis. We depreciated the transmission and interconnection costs using the 15-year MACRS schedule. We assumed that a 50% bonus depreciation is only available to 2013 installations. The Team assumed that residential systems owned by private third-parties and operated under Power Purchase Agreements (PPA) or leased with the homeowner qualify for the federal incentives available to commercial systems. Finally, we assumed investors' efficient use of federal tax incentives (which is often not the case).

#### 4.2.4 Ownership and Financing

The Team evaluated the need for and magnitude of potential incentives using three different ownership models: private third-party, private host, and public ownership. These models are consistent with the risk profile of a SREC incentive policy described in Section 3.3.

We assumed third-party owners to be private-sector entities with access to traditional financing mechanism with commercial terms reflecting current market conditions. Host owners are also private-sector entities, and we assumed they finance solar projects in a manner similar to their other corporate capital expenditures and compare potential solar installation returns to their internal corporate hurdle rate. Both third-party and host-owned projects are eligible for federal incentives. We assumed that public ownership is through a municipality or other governmental entity with bonding authority, and as publicly owned projects do not have available federal incentives

We based ownership and financing assumptions, in large part, on a series of interviews with developers, financiers, installers, and other solar industry market participants. The script associated with these interviews is included as Appendix B. Table 11 shows the range of financing assumptions we used for analyzing ownership options.

	Pri	ivate Third- Ownershi	·Party ip	ŀ	lost Owner	ship	Public Ownership		
	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground	Roof	Roof or Ground	Ground
	<15	15 - 500	500+	<15	15 - 500	500+	<15	15 - 500	500+
Debt									
% Debt	30%	30%	30%	40%	40%	40%	N/A	100%	100%
Debt Term	5	5	5	15	15	15	N/A	20	20
Interest Rate	6%	6%	6%	4%	6%	6%	N/A	4%	4%
Equity									
With ITC	15%	15%	15%	4%	12%	12%	N/A	N/A	N/A
Post-ITC*	12%	12%	12%						

#### **Table 11: Ownership and Financing Assumptions**

\* This assumes that a sunset of the ITC eventually results in access to a larger pool of less expensive investment capital.

The cost of equity is differentiated in the private third-party ownership case. While the ITC is available through 2016, deal structures dependent on effective monetization of tax benefits are expected to persist. These transactions often require attracting additional tax-motivated parties to the project financing, and at considerable expense for transaction and capital. After the ITC declines from 30% to 10% beginning in 2017,<sup>11</sup> we expect the pool of available investment capital to increase as a more traditional project finance structure emerges to replace the tax credit-driven market. We expect the increase in the amount of capital competing for project investments, coupled with a simplification of transaction structures, to reduce the cost of equity capital available to solar projects coming online beginning in 2017. Increased participation by real estate investment trusts (REITs) and master limited partnerships (MLPs) may also advance the potential for lower financing costs.

#### 4.2.5 Levelized Cost of Energy Modeling Inputs

The Consulting Team generated CREST model inputs by analyzing available databases, recent proceedings and reports from neighboring states, and interviews with market participants.<sup>12</sup> Our cost and financing assumptions were varied based on the project size, installation type, and ownership structure. For the analysis, we used Massachusetts' corporate income tax rate. The detailed inputs are included in Appendix A.

The type and amount of property tax applicable to solar installations has been the subject of much discussion throughout the Commonwealth. Legislation has been introduced on more than one occasion to establish a *percentage of revenue*-based property tax, but such proposals have failed to gain sufficient support. Cost and market value approaches have also been widely discussed, as well as whether solar facilities are more appropriately taxed as real or personal property. Payments in lieu of taxes (PILOTs) have also been widely adopted by project developers and host communities as a means of achieving mutual objectives in the absence of clear guidance from the state. Of course, certain projects—particularly those with production always consumed behind the meter—may qualify for property tax exemptions. For the purpose of this analysis, we used a combination of market research and analysis using the *Solar Valuation Worksheet* produced by the Massachusetts Department of Revenue (dated April 8, 2013) to arrive at an assumed property tax rate of \$25/kW, where applicable. We assumed this rate would remain constant throughout the project's operating life. For the purpose of this analysis, we assumed that both of the roof-mounted classifications (projects < 15 kW and projects 15-500 kW) are exempt from property taxes. We assessed the property taxes for projects of 500-6,000 kW (standard ground-mounted projects and those installed on capped landfills) at a fixed rate of \$25/kW in each year of project operation.

#### 4.3 Performance

#### 4.3.1 Technology Assumption

An analysis of the current fleet of PV installations in Massachusetts confirmed that the vast majority of installations were fixed systems, with a very small number of tracking systems (four double axis and 31 single axis). This suggests that in Massachusetts, the added revenue from increased production is rarely justified by the added cost required for the tracking. For purposes of estimating the incentive levels, we assumed that all projects were fixed rather than tracking systems. If the increased costs and increased revenues associated with installing tracking were equal (breakeven), the calculated incentive level would be roughly sufficient to support a tracking system as well.

<sup>&</sup>lt;sup>11</sup> This analysis assumes the ITC is not extended at its current 30% level.

<sup>&</sup>lt;sup>12</sup> The interview script is provided in Appendix B.

#### 4.3.2 Capacity Factor and Production Degradation

The assumed capacity factors for each market segment are shown in Table 12, and are expressed as a percentage of DC kW. For projects <15 kW, we derived the capacity factor through a review of recent production data from the *MassCEC Production Tracking System*. For other project categories, we based the capacity factor on values used in Rhode Island's 2012 Distributed Generation Standard Offer proceeding<sup>13</sup>. The capacity factor for each project size was held constant over time.

#### **Table 12: Capacity Factor Assumptions**

Installation Type/ Land Classification	Roof-Mounted <15 kW	Roof-Mounted 15-500 kW	Ground-Mounted 500-6,000 kW
Capacity Factor	13.00%	14.39%	14.65%

For each project, production is expected to degrade at a rate of 0.5% per year.

#### 4.3.3 Production Profile

For the purposes of estimating available wholesale revenue for PV installations realizing revenue in the wholesale market, the Consulting Team assumed a typical production profile. We assumed a typical PV watts profile for Boston, MA and a capacity factor of 14% DC for estimating a production-weighted energy market value for electricity sales at wholesale.

#### 4.4 Revenue

#### 4.4.1 Wholesale Sales, Forward Capacity Markets, Class 1 REC Revenue, and Net Metering Credits

As stated in Section 3.2, a forecast of revenues from the sale of energy is required to estimate the incentive requirement for a given project category. This section details the methodology for forecasting market revenues. The market value of production is estimated for the project's 25-year useful life. Depending on the scenario, this value is comprised of varying combinations of net metering credits, wholesale sales, and Class 1 RECs.

#### 4.4.1.1 Utility Rates

There are many utility service territories in Massachusetts, including the different subsidiaries of the major IOUs, smaller IOUs, and municipal light plants. Each has substantially different rate structures reflecting the unique nature of each system (different densities and line-miles per ratepayer, different historic costs and transition charges, etc.). To simplify the analysis, we used an illustrative selection of rates spanning the major utilities in different load zones to reflect a representative range of net metering credit. The net metering credit values vary widely across different service territories. This sampling is sufficient to highlight the importance of differences between utilities to the required incentive, and explains (in part) the different solar PV penetration rates in different parts of the state.

For this analysis, the avoided retail rate (attributable to behind the meter consumption) and net metering credit value of production from a solar array were assumed to be similar enough that we used a forecast of net metering credits as a proxy to value both behind the meter and virtual net metered production. We ignored the potential avoidance of kW-based demand charges, as well as the avoidance of the monthly energy efficiency and renewable energy charges for production consumer behind the meter.

<sup>&</sup>lt;sup>13</sup> Rhode Island Public Utilities Commission Docket Number 4288. <u>http://www.ripuc.org/eventsactions/docket/4288page.html</u>

For each of the four major IOUs in Massachusetts, we calculated the prevailing residential (R-1) and commercial (G-1) rates from utility tariffs (see Table 13 and Table 14). These rate classes are assigned to the majority of residential and commercial net metering facilities, respectively. Many of these rate classes have variable charges that fluctuate either based on the volume purchased or the time of year. For residential rates with volume-adjusted pricing, we applied a 90%/10% weighting to the head/tail block rate, respectively. This reflects the relationship of an installation well-matched to its on-site load. For commercial rates with volume-adjusted pricing, we applied to the head/tail block rate of virtual net metering in most applications. For any block with seasonally variable pricing, we applied a 55%/45% weighting to winter/summer rates.<sup>14</sup> Applicable blocks are noted in the tables below.

	Rate Net				Basic Total 201	
	Code	Distribution	Transition	Transmission	Service	NMC Value
Mass Electric	R-1	\$0.0346	\$0.0016	\$0.0213	\$0.0725	\$0,1300
(National Grid)*	=	<i>+</i> 010010	<i><b>↓</b>0.0010</i>	+010-10	<i>\</i>	<i>+</i> 01 <u></u> 0000
WMECO*	R-1	\$0.0519	\$0.0068	\$0.0162	\$0.0732	\$0.1480
Boston Edison	P_1	\$0.0487	\$0 0088	\$0.0176	\$0.0703	\$0 1 <i>454</i>
(NStar)	1/-1	Ş0.0487	ŞU.0088	Ş0.0170	ŞU.0703	Ş0.14 <u>9</u> 4
Commonwealth	P_1	\$0.0522	\$0.0202	\$0.0186	\$0.0703	\$0.1716
Electric (NStar)*	1/-1		JU.UZ93	20.0100	JU.U/US	Ş0.1710

#### Table 13: Breakdown of Residential Net Metering Credit Components (\$/kWh)

\*Volume-tiered pricing uses 90%/10% weighting for head/tail blocks

\*\*Seasonal pricing uses 55%/45% weighting for winter/summer rates

	Rate Code	Net Distribution	Transition	Transmission	Basic Service	Total 2013 NMC Value
Mass Electric	C 1	¢0,0200	¢0.0016	¢0.0177	¢0.0690	¢0 1262
(National Grid)*	G-1	\$0.0390	\$0.0010	\$0.0177	ŞU.0680	\$0.1263
WMECO	G-0	\$0.0120	\$0.0068	Fixed Fee	\$0.0757	\$0.0945
Boston Edison	C 1	¢0.0596	¢0,0000	¢0.0227	60.070F	¢0.1606
(NStar)**	6-1	ŞU.US80	ŞU.UU88	\$0.0227	\$0.0705	\$0.1000
Commonwealth	C 1	¢0.0406	¢0.0202	¢0.0100	60.070F	ĆO 1504
Electric (NStar)	G-1	ŞU.U4U6	\$0.0293	\$0.0190	\$0.0705	ŞU.1594

#### Table 14: Breakdown of Commercial Net Metering Credit Components (\$/kWh)

\* Volume tiered pricing uses 10%/90% weighting for head/tail blocks.

\*\* Seasonal pricing uses 55%/45% weighting for winter/summer rates.

We considered each rate component individually with respect to the net metering credit forecast. First, we assumed transmission and distribution charges to escalate at the rate of inflation, which is represented in this case by the Energy Information Administration's *Annual Energy Outlook 2013* forecast of Consumer Price Index (CPI). Second, given the uncertainty associated with the transition charge, we assumed that it phases out linearly over five years, reaching 0% of its 2013 value in 2018. Finally, we derived the basic service charge (the generation component) through a solar production-weighting of the most current 12 months of basic services rates available from each utility. We then

<sup>&</sup>lt;sup>14</sup> Winter rates apply to October through May. Summer rates apply to June through September. When solar production weighting is taken into account, the seasonal weighting is 55%/45% winter summer rather than the unweighted 66%/34%.

escalated this rate at the same rate as the wholesale energy price forecast, which is detailed in Section 4.4.1.2. Figure 16 depicts the resulting composition of Massachusetts Electric's G-1 net metering credit rate. The figure demonstrates that the majority of escalation over time can be attributed to the market's expectations for long-term natural gas and associated wholesale electricity price increases, which include embedded assumptions about the cost of potential future carbon regulations, among others, for which there is substantial uncertainty.





Figure 27 and Figure 28 show the combined forecasted values for each net metering credit category, across all utilities assess in this analysis.



Figure 27: Residential Net Metering Credit Forecast (\$/kWh, nominal)





#### 4.4.1.2 Wholesale Electricity Rates

Under certain futures, detailed in Section 4.4.2, some or all production from certain projects may not be eligible to receive Net Metering Credits. Instead, such production would receive only the wholesale value of electricity. Wholesale energy prices were forecast from 2014-2039 by LaCapra Associates using the Aurora production cost simulated model.

The model generated a solar production-weighted average Locational Marginal Price (LMP) forecast across all zones in Massachusetts. This represents the realized revenue for all solar installations in the Commonwealth. As a result, this same forecast is used across all utilities, and is illustrated in Figure 3 below. See Appendix C for key assumptions underlying the forecast of wholesale electric energy prices.



Figure 29: Massachusetts Solar Production Weighted LMP Forecast (\$/MWh, nominal)

Due to the fact that wholesale energy revenues are unpredictable and, more importantly, unhedgeable over the 25-year expected life of a solar installation, this analysis discounts the forecasted wholesale revenues assumed to be available to non-residential projects after the current net metering regime is no longer available. This discounting is meant to reflect the view of potential project financiers evaluating an investment opportunity, and thus is applied only to the incentive calculation and not to the benefits projection under Task 3. Wholesale revenues are discounted by 5% in 2013 and 40% in 2039, with linear interpolation in between.

#### 4.4.2 Forward Capacity Market Revenues

Since renewable energy facilities have not been granted an exemption from the Forward Capacity Auction's minimum offer price rule (MOPR), this analysis assumes that the solar facilities modeled do not have access to Forward Capacity Market revenues.

If solar facilities are eventually able to participate in the FCM, they would receive 30% of nameplate rating during the summer and 0% during the winter months. As with wholesale electricity revenues, however, this revenue is not able to be hedged and any revenue forecast should be discounted accordingly. More value may be available to projects interconnected behind the meter or participating as load reducers.

#### 4.4.3 Class 1 Renewable Energy Credit Revenue

In addition to applicable electricity revenues, solar installations participating in the SREC program are eligible to sell Class 1 RECs and collect associated revenues after their SREC eligibility expires. In the long-term, the Class 1 market is expected to demonstrate REC prices consistent with the cost of entry for the marginal generating unit. As with wholesale sales, however, investors evaluating a solar transaction today cannot hedge Class 1 REC price risk. As such, long-term Class 1 REC revenues are assumed at \$25/MWh. This revenue is applied to all kWh produced for project years 11 through 25.

#### 4.4.4 Net Metering

In Massachusetts, current regulations allow projects and hosts to net meter production, a system in which electricity production and usage are balanced on a monthly, rather than real-time basis, and in which dollar credits (calculated based on net excess generation) can be rolled forward to apply against future utility charges. The components of retail rates that are offset by net-metered production vary based on the size of the project, and are divided into three classes in Massachusetts, detailed in Table 15.

Class I	≤ 60 kW			
Class II	> 60 kW – 1,000 kW			
Class III	> 1,000 kW – 2, 000* kW			
* The Class III maximum capacity is <i>per facility</i> for				
private projects and per unit for public projects.				

#### **Table 15: Massachusetts Net Metering Size Classifications**

Class I, II and III (if power is contracted to a government entity) receive credit for the kilowatt-hour basic service, distribution, transmission, and transition charges associated with their production. Class III projects, when hosted/contracted by a non-governmental entity, receive all of the above with the exception of kilowatt-hour distribution charges. This analysis assumes that any Class III project would be hosted by or contracted with a government entity to capture the full value of the net metering credits.

At the end of each billing cycle, excess net metering credits (in dollars, not kWh) can be carried forward for use in the next billing period. This carry over can be continued indefinitely, and can be used to match a generator's production to one (or more) party's annual demand. This can also be done with multiple end-users of the power through a process known as virtual net-metering.

The ability to match annual production and electricity demand is of significant value to both net metering credit buyer and seller, and allows for larger projects (sizing to average load, rather than minimum). Net metering also creates a cost to ratepayers, and as a result the policy is currently capped at 6% of each utility's peak demand<sup>15</sup>. This total is split evenly between projects serving private (3%) and public (3%) entities. It is possible that the state will increase this cap over time, so the analysis considers a future with (NM-NoCap) and without (NM-Cap) the availability of net metering credit value.

In the NM-NoCap future, the market value of production from all modeled projects is assumed to be based 100% on net metering credits. When the cap is reached in the NM-Cap future, it is nonetheless assumed that the roof-mounted < 15 kW segment will always be sized relative to load such that its production will always capture a value that approximates avoided retail charges (represented in this analysis by the net metering credit value). By comparison, when the cap is reached in the NM-Cap case, 50% of the production from a 15-500 kW project is assumed valued at avoided retail rates (represented by the net metering credit value) and 50% of the production is assumed valued at wholesale rates. For projects 500-6,000 kW, 100% of the production is assumed valued at wholesale rates.

<sup>&</sup>lt;sup>15</sup> Small renewable distributed generation systems are exempt from the cap. Small is defined as < 10 kW on a single-phase circuit and < 25 kW on a three-phase circuit. For the purposes of this study, this exemption is assumed to apply to all installations within the <15 k residential market segment.

#### 4.4.5 PPAs

In the host-ownership cases, the owner is assumed to benefit from the <u>full</u> net metering credit (when it applies) plus any incentive payments. By contrast, the third-party ownership cases assume that securing a Power Purchase Agreement (PPA) will require the owner to take payment at a discount to the full net metering credit value, consistent with current market practices (i.e. the host requires some degree of expected savings; conveying the full value of the net metering credits would not be a compelling break-even transaction). The assumed discounts to the net metering credit (which represents savings to the host customer with which the PPA is signed) are summarized in Table 16. Under these assumptions, a 1 MW, ground mounted, third-party owned project would receive 85% of the net metering credit value. In cases where the project is only receiving wholesale value for electricity, there is no PPA discount but the project receives assumed discounted wholesale revenue as defined in 4.4.1.2.

	<i>i n</i>
Project Category	PPA Discount (savings to host)
Roof < 15 kW	5%
Roof/Ground 15 -500 kW	15%
Ground 500-6000 kW	15%
Landfill 500-6000 kW	15%

#### Table 16: Project Categories by Size and Installation Type

#### 4.4.6 Interpreting Key Assumptions in the Context of Policy Objectives

The modeling assumptions and results in this analysis are intended to help support informed decision making, and are not intended to prescribe incentive rates directly. Policy makers will need to interpret these results in the context in which the data are made available as well as the context of their policy objectives – because policy objectives influence incentive design.

If policymakers seek to encourage a diversity of project locations, sizes, configurations and ownership structures then an aggressive price point may be appropriate. If policy objectives target only the most cost effective projects, then a more conservative price may be preferred, even if it only supports a much narrower set of project sizes and types.

Understanding these objectives will help policy makers determine which cost cases and trajectories, and which sensitivities best align with the incentives and price signals the Commonwealth wishes to send to the market.

Several key assumptions are influenced by complex data and/or uncertainties which create a wide range of potential incentive outcomes. For example, the mean solar installed cost value that was used as the basis for this analysis was heavily influenced by the manner in which Federal incentives affected the way solar installed costs have been reported over the past several years. Since the ITC and cash payment in lieu thereof are cost-based, there might have been a tendency for developers to overstate – or at least aggressively interpret – the total costs eligible for Federal incentives. If true, the costs reported to the databases used in this analysis would tend to overstate the actual installed cost of solar during this time period, which would drive up the necessary incentive calculated in this analysis. There is little in the way of public data, however, to confirm or quantify this possible effect. In addition, the use of mean values from the DOER installed cost range reflected in the database, for example, may have only been viable in situations where lower financing costs or higher utility rates were available; in such instances, use of a value lower than the mean may be more appropriate for projecting needed incentives. Nonetheless, it may still be meaningful to consider these issues in the context of active programs in the Commonwealth. Solarize Mass, for example, appears to be spurring new

projects at costs on the low end of the range considered in this report. While anecdotal, this evidence may suggest that policy makers should consider the results based on lower installed costs and less costly financing and lower customer acquisition costs when setting new solar incentives.

The impact on incentives of several other assumptions should also be carefully considered. Due to the inability to hedge against downside risk in long-term electricity markets, forecasted wholesale revenues are discounted at 5% in 2013 and 40% in 2039. All else equal, if this discounting is either higher or lower than a project investor would use, then the needed incentive may differ. Similarly, this analysis assumes that forward capacity market revenues are not available to solar projects currently under development – due to the lack of exemption to the minimum offer price rule, among other factors. Also, this analysis determined that avoiding kW-based demand charges was site-specific and could not be predicted with accuracy in aggregate. All else equal, these assumptions could tend to overstate the required incentives if projects are able to realize capacity revenue or avoid demand charges.

Property taxes is one area that could either increase or decrease incentives. While this analysis estimates potential property tax levies (or negotiations) based on the best available information, it is possible that legislative action on this issue will create exemptions or obligations which vary significantly from the inputs assumed in this report.

Solar economics are also impacted by Federal incentives. In addition to the ITC, Federal accelerated depreciation is a cornerstone incentive for renewable energy development. For the last several years, the IRS has offered significant bonus depreciation in the project's first operating year. In 2011 the bonus depreciation was 100%. In 2012 and 2013, the bonus depreciation is 50%. The expiration of bonus depreciation beginning January 1, 2014 places upward pressure on the incentives required to encourage solar development.

Finally, it is important to note that these assumptions – and others included in this incentive analysis – are constantly shifting. Many projects may have been initiated based on one set of cost assumptions, and now face contracting and financing negotiations in the context of much higher interconnection and property tax expenses. Investors in such projects may be forced to consider sub-market returns (or returns lower than originally envisioned) rather than lose their invested capital. Assuming a lower realized return on equity would exert significant downward pressure on required incentives.

# Appendix A.

# **Detailed CREST Model Inputs**

		Roof- Mounted	Roof or Ground	Ground- Mounted	Landfill
		<15	15 - 500	500+	500+
Project Size and Performance	Units		10 000		
Generator Nameplate Capacity	kW	5	250	1500	1500
Net Capacity Factor, Yr 1	%	13.00%	14.39%	14.65%	14.65%
Annual Production Degradation	%		0.5	0%	
Project Useful Life	years		25 y	25 years	
Capital Costs	Units	-			
Generation Equipment	\$/kw		Per Cost Forecast		
Interconnection	\$/kw	Per Cost Forecast			
<b>Operations &amp; Maintenance</b>	Units				
Fixed O&M Expense, Yr 1	\$/kW-yr	20.00	20.00	15.00	15.00
Variable O&M Expense, Yr 1	¢/kWh	0	0	0	0
Insurance, Yr 1 (% of Total Cost)	%	0.30%	0.30%	0.30%	0.30%
Project Management Yr 1	\$/yr	\$0	\$3,500	\$10,000	\$10,000
Property Tax or PILOT, Yr 1	\$/yr	\$0	\$0	\$37,500	\$37,500
Annual Property Tax Adjustment					
Factor	%	0%	0%	0%	0%
Land Lease	\$/yr	\$0	\$10,000	\$35,000	\$35,000
		4			
Initial Funding of Reserve					
Accounts	Units				
Debt Service Reserve					
# of months of Debt Service	months	nths included in total project cost estimate			ate
O&M Reserve/Working Capital		-			
# of months of O&M Expense	months	included in total project cost estimate			
# Appendix B. Survey Questions

- 1. What role does your company play in the solar industry? (i.e. developer, investor, etc.)
- 2. What has been the nature of your participation (level of experience) in the <u>Massachusetts</u> SREC carveout market to date?
- 3. What market segment(s) do you focus on?
  - a. Residential (please specify 3<sup>rd</sup>-party ownership, direct ownership, or both)
  - b. Medium C&I/roof
  - c. utility/ground mounted scale
  - d. other
- 4. Please summarize your company's experience financing solar projects.
- 5. How do you expect that most of your solar projects in Massachusetts will be financed?
  - a. Project financed?
  - b. Balance sheet financing?
  - c. Other? (describe)
- 6. If you are involved in other state solar markets (like NJ, or NY), was there a difference in cost of capital or capital structure between those markets and Massachusetts?
- 7. Let's discuss project capital structure, and the cost of debt and equity. We would like to understand how these assumptions might change based on policy design:

	SREC/no	SREC/Floor	Standard	Competitive
	floor		Offer	Procurement
Perm. Financing,				
Debt:				
%,				
Term,				
Interest rate,				
Target avg. DSCR,				
Source				
Perm. Financing,				
Tax Equity:				
%,				
AT Target IRR, & Source				
Perm. Financing,				
Sponsor/Cash Equity:				
%,				
AT Target IRR, &				
Source				
WACC: As a fall-back, ask about				
differences in WACC, by policy?				
Construction Finance:				
%, Int. Rate & Source, AT Target IRR, &				
Source would there be any distinction				
expected among policies?				
How would transaction costs differ				
<b>between policies?</b> What types of (soft)				
costs - customer acquisition costs,				
administrative overhead, financing,				
anything else suggested by interviewee -				
are incurred, increased, minimized or				
avoided?				
Which policy option do you favor and				
why?				

#### 8. (only ask if interviewee plays in residential sector)

- a. Consider a residential PV project:
  - i. owned by the homeowner and financed through a local community bank, *versus*
  - ii. the same project owned, installed and maintained by a 3<sup>rd</sup>-party with nationally-based investors and with a lease or power purchase agreement with the homeowner.

How would you expect the target return on equity, cost of debt, d/e ratio, and/or transaction & overhead costs to differ between the two?

b. DOER is considering a variation on the SREC market model for the residential sector which would involve forward-minting of SRECs. Would you be willing to respond to a brief online survey which further explains the policy, and solicits your reaction to program parameters and opinion on impact on financing or other cost drivers?

#### 9. (only ask if interviewee plays in C&I sector)

- a. Consider a medium scale (e.g. 500 kW) fully net metered PV project owned by:
  - i. a group of small, local investors through a "community solar garden" financial model, *versus*
  - ii. the same project owned, installed and maintained by a 3<sup>rd</sup>-party with nationally based investors.

How would you expect the target return on equity, cost of debt, d/e ratio, and/or transaction & overhead costs to differ between the two?

b. What do you think the impact of applicable SEC regulation would have on the community solar garden model? Are you aware of community financing schemes that have managed to satisfy SEC issues in a commercially-viable manner?

#### 10. (only ask if developer plays in the +500 ground mount sector)

- a. Does siting projects on landfill sites impact overall system installed costs and if so, by how much on a percentage basis?
- 11. Do you have suggestions regarding others to interview?

## Appendix C. Wholesale Market Price Forecast Key Assumptions

Market energy price projections are derived from the La Capra Associates Northeast Market Model ("NMM"). The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model on the AURORAxmp<sup>®</sup> software platform ("AURORA"). The model provides a zonal representation of the electrical system of New England and the neighboring regions. For New England, the zones and corresponding transfer capabilities represented in the model conform to the information provided in ISO New England's Regional System Plan.

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

The NMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand, and transmission configurations. EPIS, the developer of AURORA, provides a default database, which La Capra Associates supplements with updates to key inputs for the New England market.

The NMM is used to develop a forecast that is representative of a 50/50 price outlook over the longterm. The reference case assumptions for the 50/50 market price forecast are described in more detail below.

- Retirement assumptions: The retirement assumptions are developed as part of the thermal expansion development process. The schedule of retirements is based on both publicly announced retirements and the de-list bids from the ISO-NE Forward Capacity Auctions ("FCA"). While submitting a de-list bid in advance and being approved is not a guarantee that the unit will retire, using the FCA results provides for a retirement schedule that is based on publicly-available market information that is not specific to any particular study. For years in which no FCA had yet cleared, professional judgment was used to determine an expected life for the oil-fired and coal-fired units remaining online in New England. No nuclear units in New England are projected to retire in the study period.
- Natural Gas:
  - Henry Hub: Prices are a blend of EIA's May 2013 Short-Term Energy Outlook (2013-2015) and EIA's 2013 Annual Energy Outlook ("AEO") (2015 and after).
  - New England Basis Differential: Basis differential is a blend of Algonquin City Gate Basis
    Swap Futures for the short-term (2013-2015) and the implied basis differential from EIA's
    2013 AEO in the long-term (blended until 2020 and fully from the 2013 AEO thereafter).
- **Carbon Policy/Price:** All New England states participate in RGGI, a cap-and-trade program aimed at reducing CO<sub>2</sub> emissions from the power sector. On February 7, 2013 the RGGI states announced their commitment to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will

rise from about \$4 (2010\$) per ton in 2014 to over \$10 (2010\$) per ton by 2020.<sup>16</sup> The NMM incorporates this updated outlook on RGGI allowance prices. After 2020, the reference case assumes that a national  $CO_2$  pricing program is implemented and that prices will reflect the "Low" case of Synapse Energy Economics, Inc.'s 2012 Carbon Dioxide Price Forecast.<sup>17</sup>

- New Renewable Generation: PTC, RPS Imports etc. [See Task 3 Report for details].
- Inflation: The NMM uses the GDP Chain-type Price Index from the Macroeconomic Indicators table of the 2013 AEO.
- Load and DSM: The 2013 CELT report was used to estimate gross peak and energy load and peak and energy load net of energy efficiency (EE) for the first ten years of the study period. For later years, gross load is assumed to grow at the 2016-2021 compound annual growth rate. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2021 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.
- **Transmission:** The NMM assumes the following upgrades to the existing New England transmission system:
  - The Maine Power Reliability Project (Completed by 2013);
  - Northern Pass (Completed by 2019); and
  - New England East-West Solution (Greater Springfield Reliability Project completed by 2014; Interstate Reliability Project completed by 2016).

<sup>16</sup> RGGI, Inc. 2/7/2013 Press Release. http://www.rggi.org/docs/PressReleases/PR130207\_ModelRule.pdf
 <sup>17</sup> Synapse, http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-

Forecast.A0035.pdf

## Appendix D. 10-Year Levelized Incentive Requirements, All Scenarios and Sensitivities

### Part 1: 3<sup>rd</sup>-Party Private Ownership



Figure 30 Incentive Requirement: Roof Mounted < 15 Residential kW (Low Cost Case) NM-NoCap

Figure 31 Incentive Requirement: Roof Mounted < 15 kW Residential (Base Cost Case) NM-NoCap





Figure 32 Incentive Requirement: Roof Mounted < 15 kW Residential (High Cost Case) NM-NoCap







Figure 34 Incentive Requirement: Roof Mounted 15-500 kW (Low Cost Case) NM-Cap







Figure 36 Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case) NM-Cap

Figure 37 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-NoCap





Figure 38 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-Cap







Figure 40 Incentive Requirement: Ground Mounted 500+ kW (Low Cost Case) NM-Cap







Figure 42 Incentive Requirement: Ground Mounted 500+ kW (Base Cost Case) NM-Cap







Figure 44 Incentive Requirement: Ground Mounted 500+ kW (High Cost Case) NM-Cap







Figure 46 Incentive Requirement: Landfill Mounted 500+ kW (Low Cost Case) NM-Cap







Figure 48 Incentive Requirement: Landfill Mounted 500+ kW (Base Cost Case) NM-Cap







Figure 50 Incentive Requirement: Landfill Mounted 500+ kW (High Cost Case) NM-Cap





Figure 51 Incentive Requirement: Roof Mounted < 15 kW Residential (Low Cost Case) NM-NoCap

Figure 52 Roof Mounted < 15 kW Residential (Low Cost Case) NM-NoCap, Host Ownership, with Res. Tax Credit





Figure 53 Incentive Requirement: Roof Mounted < 15 kW Residential (Base Cost Case) NM-NoCap

Figure 54 Roof Mounted < 15 kW Residential (Base Cost Case) NM-NoCap, Host Ownership, with Res. Tax Credit





Figure 55 Incentive Requirement: Roof Mounted < 15 kW Residential (High Cost Case) NM-NoCap

Figure 56 Roof Mounted < 15 kW Residential (High Cost Case) NM-NoCap, Host Ownership, with Res. Tax Credit





Figure 57 Incentive Requirement: Roof Mounted 15-500 kW (Low Cost Case) NM-NoCap

Figure 58 Incentive Requirement: Roof Mounted 15-500 kW (Low Cost Case) NM-Cap





Figure 59 Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case) NM-NoCap

Figure 60 Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case) NM-Cap





Figure 61 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-NoCap

Figure 62 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-Cap





Figure 63 Incentive Requirement: Ground Mounted 500+ kW (Low Cost Case) NM-NoCap

Figure 64 Incentive Requirement: Ground Mounted 500+ kW (Low Cost Case) NM-Cap





Figure 65 Incentive Requirement: Ground Mounted 500+ kW (Base Cost Case) NM-NoCap

Figure 66 Incentive Requirement: Ground Mounted 500+ kW (Base Cost Case) NM-Cap





Figure 67 Incentive Requirement: Ground Mounted 500+ kW (High Cost Case) NM-NoCap

Figure 68 Incentive Requirement: Ground Mounted 500+ kW (High Cost Case) NM-Cap





Figure 69 Incentive Requirement: Landfill Mounted 500+ kW (Low Cost Case) NM-NoCap

Figure 70 Incentive Requirement: Landfill Mounted 500+ kW (Low Cost Case) NM-Cap





Figure 71 Incentive Requirement: Landfill Mounted 500+ kW (Base Cost Case) NM-NoCap

Figure 72 Incentive Requirement: Landfill Mounted 500+ kW (Base Cost Case) NM-Cap





Figure 73 Incentive Requirement: Landfill Mounted 500+ kW (High Cost Case) NM-NoCap

Figure 74 Incentive Requirement: Landfill Mounted 500+ kW (High Cost Case) NM-Cap







Figure 75 Incentive Requirement: Roof Mounted 15-500 kW (Low Cost Case) NM-NoCap

Figure 76 Incentive Requirement: Roof Mounted 15-500 kW (Low Cost Case) NM-Cap





Figure 77 Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case) NM-NoCap

Figure 78 Incentive Requirement: Roof Mounted 15-500 kW (Base Cost Case) NM-Cap





Figure 79 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-NoCap

Figure 80 Incentive Requirement: Roof Mounted 15-500 kW (High Cost Case) NM-Cap





Figure 81 Incentive Requirement: Ground Mounted 500+ kW (Low Cost Case) NM-NoCap







Figure 83 Incentive Requirement: Ground Mounted 500+ kW (Base Cost Case) NM-NoCap

Figure 84 Incentive Requirement: Ground Mounted 500+ kW (Base Cost Case) NM-Cap





Figure 85 Incentive Requirement: Ground Mounted 500+ kW (High Cost Case) NM-NoCap

Figure 86 Incentive Requirement: Ground Mounted 500+ kW (High Cost Case) NM-Cap





Figure 87 Incentive Requirement: Landfill Mounted 500+ kW (Low Cost Case) NM-NoCap

Figure 88 Incentive Requirement: Landfill Mounted 500+ kW (Low Cost Case) NM-Cap




Figure 89 Incentive Requirement: Landfill Mounted 500+ kW (Base Cost Case) NM-NoCap

Figure 90 Incentive Requirement: Landfill Mounted 500+ kW (Base Cost Case) NM-Cap





Figure 91 Incentive Requirement: Landfill Mounted 500+ kW (High Cost Case) NM-NoCap

Figure 92 Incentive Requirement: Landfill Mounted 500+ kW (High Cost Case) NM-Cap

