



SOLAR MARKET DEVELOPMENT VOLATILITY IN NEW JERSEY

Prepared for the Rutgers University Center for Energy,
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ABOUT THIS REPORT

This research report was produced by Meister Consultants Group, Inc. (MCG) and Sustainable Energy Advantage, LLC (SEA) for the Rutgers University Center for Energy, Economic and Environmental Policy (CEEPP) in support of its work for the New Jersey Board of Public Utilities (BPU) on solar market development volatility.

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LIST OF ACRONYMS

ACE - Atlantic City Electric
ACP - Alternative Compliance Payment
BGS - Basic Generation Service
BPU - Board of Public Utilities
CEFIA - Clean Energy Finance Investment Authority
C-PACE - Commercial Property-Assessed Clean Energy
CSI - California Solar Initiative
EY - Energy Year
GIS - Generation Information System
ITC - Investment Tax Credit
IOU - Investor Owned Utility
JCP&L - Jersey Central Power & Light
LSE - Load Serving Entity
Mass DOER - Massachusetts Department of Energy Resources
MSEIA - Mid-Atlantic Solar Energy Industries Association
NYSERDA - New York State Energy Research and Development Authority
OCE - New Jersey Office of Clean Energy
PACE - Property-Assessed Clean Energy
PV - Photovoltaic
RECO - Rockland Electric Company
REC - Renewable Energy Credit
RFP - Request for Proposal
RPS - Renewable Portfolio Standard
SACP - Solar Alternative Compliance Payment
SEIA - Solar Energy Industries Association
SREC - Solar Renewable Energy Credit

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EXECUTIVE SUMMARY

Over the past several years, New Jersey has consistently had one of the largest state solar markets in the United States and is currently ranked third nationally in total installed solar capacity. In New Jersey, solar installations are supported by a number of federal and state incentives, including an obligation on electricity Load Serving Entities (LSEs) to provide an increasing portion of the state's total electricity consumption from in-state solar installations. This solar requirement within New Jersey's Renewable Portfolio Standard (RPS) has been critical to industry growth.

The solar market has seen significant variation in installation rates over the last several years. In response to enhanced federal incentives, rapid decreases in solar installation costs and high prices in the New Jersey SREC market, the state saw a rapid increase in capacity additions during late 2011 and early 2012. These increases caused the market to substantially exceed the capacity needed to meet the legislatively established RPS schedule and led to SREC oversupply conditions. This supply-demand imbalance caused the price of the state's SREC incentive to decline to levels that resulted in a slowdown in solar installations.

In response to these developments, the New Jersey legislature passed the Solar Act of 2012, a comprehensive law intended to stabilize the solar market by increasing near-term RPS solar requirements and reducing the potential future impact of large PV systems on the market. In addition to these and other provisions, the Solar Act required the New Jersey Board of Public Utilities (BPU) to "investigate approaches to mitigate solar development volatility." This report has been commissioned by the BPU as part of that effort. The goals of this paper are to:

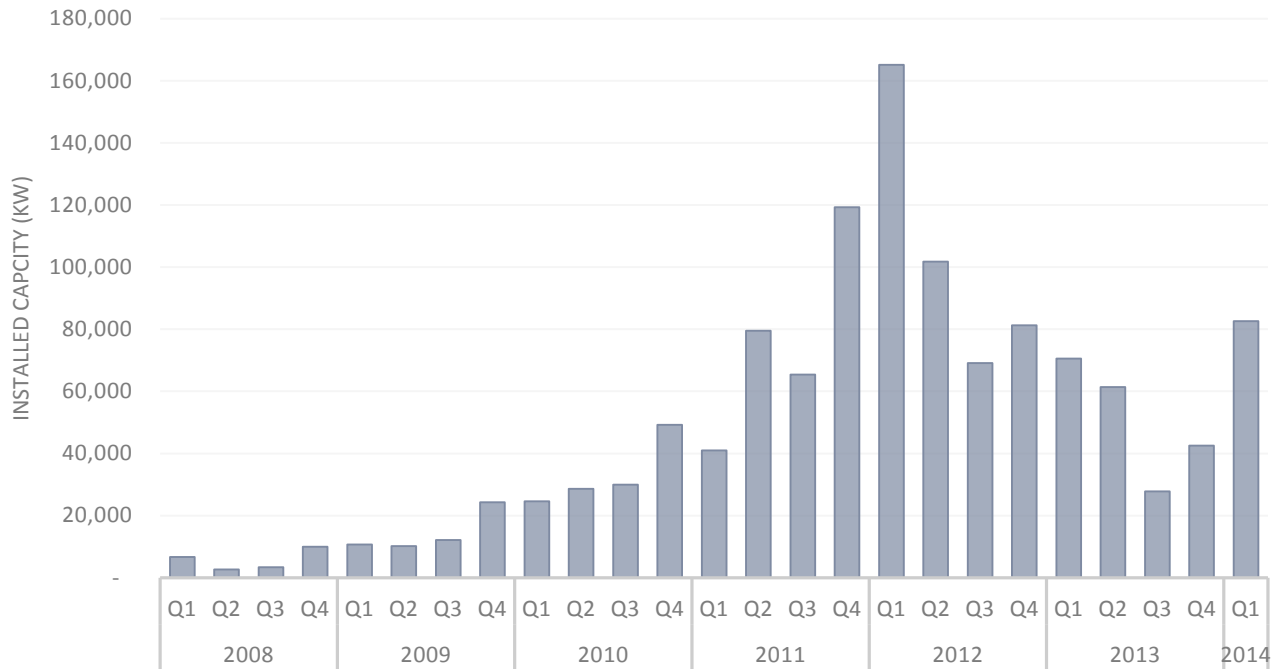
- Analyze previous performance of the New Jersey solar market with a specific focus on market development volatility,
- Identify potential future drivers and mitigants of solar development volatility, and
- Suggest potential policy options to encourage stable market growth based on models used in other states and internationally.

As part of this process, the BPU solicited feedback from New Jersey solar stakeholders regarding how to define solar market development volatility and potential options for reducing potential future volatility. This stakeholder engagement included several rounds of public comment along with a public forum held in April 2014 at the Rutgers University Bloustein School of Planning and Public Policy. There was little consensus amongst stakeholders as to the definition of solar market development volatility. Given this, the authors of this paper have chosen to define solar market development volatility as significant and rapid changes in market capacity additions over time both in aggregate capacity and within sectors.

New Jersey Solar Market Performance

As mentioned above, the New Jersey solar market has seen significant changes in capacity additions over the past several years. Figure 1 below shows quarterly market capacity additions between 2008 and Q1 2014 based on administration data compiled as part of the SREC registration program.

Figure 1. Quarterly New Jersey Solar Capacity Additions in kW (2008-Q1 2014)



As Figure 1 shows, the New Jersey market had a period of sustained growth between 2008 and 2010. The market had rapid growth during 2011 and the early part of 2012. This was followed by a period of decline in quarterly capacity additions over the remainder of 2012 and into 2013. As previously mentioned, these market dynamics have been influenced by changes to federal incentives, substantial declines in solar module costs and SREC price fluctuations reflecting supply and demand dynamics over this period. A more detailed analysis of these dynamics, as well as a review of solar market capacity additions over time by installation type is contained in this report.

Solar Market Development Volatility Drivers and Mitigants

Stakeholders participating in the BPU public process, as well as those engaged directly in the development of this report, provided a number of perspectives about the potential for future solar market volatility in New Jersey. Some stakeholders felt that the regulatory changes created by the Solar Act had reduced the likelihood of future solar market volatility, while others advocated for policymakers to make further changes to the market structure to mitigate future volatility risks.

Stakeholders expressing concerns about potential future volatility tended to list the following volatility drivers as areas of concern:

- Price volatility in the state’s SREC market,
- Challenges related to long-term planning and SREC contracting,
- Issues related to market transparency, and
- Concerns regarding regulatory stability and the enabling policy environment.

In addition to these stakeholder-identified potential future volatility drivers, the authors have, based on literature review and their own experiences, identified several other market features that could drive future volatility. These include:

- ⦿ A period of decreasing or flat annual incremental targeted capacity additions in the legislated SREC demand schedule that could result in future persistent oversupply conditions,
- ⦿ Potential volatility caused in the later years of the current RPS schedule when projects built in the 2010-2013 period begin to lose their 15-year eligibility to generate SRECs,
- ⦿ Expiration of the current 30 percent Federal Investment Tax Credit (ITC) in 2016 which has the potential to create rapid market capacity additions as developers accelerate development to meet the incentive deadline, and
- ⦿ General issues related to policies with demand curves that are not responsive to market supply.

The New Jersey solar market also has a number of key features that will likely mitigate future market development volatility. Many of these were implemented as part of the Solar Act in response to the events of the 2011-2012 period and could be expected to prevent the extreme market conditions that were evident during that time. These market volatility mitigants include:

- ⦿ Financing and procurement programs supported through the state's Electric Distribution Companies (EDC) that can help lessen potential market volatility through regular planned capacity procurements, and
- ⦿ Future limits on large grid-supply solar projects that have the potential to rapidly alter market supply and demand dynamics.

Solar market development volatility drivers and mitigants are discussed further in Section 2 of this report.

Example Incentive Models and Policy Options

Solar market policy tools and approaches to mitigate volatility are evaluated in Section 3 of this report. These were derived from both stakeholder comments to the BPU and research on both national and international incentive models. Policy models are presented and evaluated using the BPU's evaluation criteria governing the use of ratepayer funds in the solar market. These are:

- ⦿ Creation of a sustained orderly market,
- ⦿ Minimization of ratepayer costs,
- ⦿ Creation of a diverse market place, open to participation from an array of ratepayer classes,
- ⦿ Market transformation that lead to long-term reductions in required incentives, and
- ⦿ Consistency with current legislative policies and structures.

The evaluated options range from approaches complementary to the current structure to ideas which would require significant market redesign. Policies evaluated include:

- ⦿ Expanding the current EDC contracting programs,
- ⦿ Developing a green bank financing initiative,
- ⦿ Implementing a supply-responsive demand formula,

- Shifting to a competitive procurement incentive model (i.e. auctions),
- Shifting to a standard offer contracts incentive model, and/or
- Establishing an SREC market price floor.

Four potential policy options are reviewed in Section 3 and the benefits and challenges of each are discussed. These options are intended to give policymakers a range of potential pathways for reducing future solar market volatility in New Jersey. The options range from a 'hands off' approach that requires no further action to a significant transition away from the state's current incentive model. These are listed and discussed below:

Option 1: No Substantive Policy Changes

Under this option, policymakers would make no changes to the current market other than those legislated in the Solar Act. This option has the highest likelihood of leading to future market development volatility; however provisions in the Solar Act have already reduced the likelihood of future volatility as well as the potential costs to ratepayers from volatility. The Solar Act's expansion of SREC bankability from three to five years, together with the reduction in the SACP schedule, limits the range of SREC prices between long and short market conditions and should contribute to reduced future market volatility. This policy option was favored by a number of stakeholders both in their formal comments and in interviews conducted during the development of this report.

Option 2. Implementation of Complementary Initiatives

This policy option includes a range of market interventions that do not change the structure of the existing New Jersey incentive program. The initiatives discussed in this report include expansion (both in size and scope) of the existing EDC long-term contracting programs as well as the creation of solar financing programs under a green bank model. Both these initiatives are likely to reduce future potential solar market development volatility and could also support efforts to transition the New Jersey solar market away from SREC incentives. The EDC financing programs are well established and have been popular with market participants. Development of green bank financing programs may require new legislation, but could be modeled after the state's current efforts to develop an energy resilience bank.

Option 3: Supply-Responsive Demand Formula with an SREC Price Floor

Under the current renewable portfolio standard, annual demand for SRECs is fixed through a legislative schedule and is not responsive to changes in solar market conditions. Implementing a policy that adjusts SREC demand based on current market conditions could lower development volatility and make the New Jersey market more resilient to external changes that affect growth. This policy option could be coupled with an SREC price floor that would support SREC prices during period of over-supply in order to prevent significant declines in installation activity. Implementing a supply-responsive demand policy would be a major transition and would likely require new authorizing legislation.

Option 4: Implement a Capped-Quantity Incentive

Implementing a capped-quantity incentive program in which a limited number of systems are provided incentives over a given period of time would significantly limit the potential for future solar market development volatility. Similar policies have been implemented in a number of states including New York, Connecticut, Delaware, Rhode Island and California. This policy option could be implemented through an auction-based approach or by offering standard long-term incentive contracts on a first-come-first-served basis. Whereas this option would provide the greatest benefit related to reducing solar market development volatility, transitioning the New Jersey market to a capped-quantity incentive would require a significant market restructuring.

SECTION 1 INTRODUCTION

New Jersey has had one of the most robust solar markets in the United States. Spurred by federal incentives, a supportive state-level renewable portfolio standard (RPS) solar requirement and significant declines in the installed cost of solar systems, New Jersey has established itself as a national leader in solar market development. Solar installation activity in the New Jersey has been uneven over the course of the last several years, with periods of rapid capacity additions followed by periods of declining market activity. In addition to this volatility in market capacity additions over time, the price of solar renewable energy credits (SRECs) has also fluctuated significantly. This report evaluates the causes of solar market development volatility in New Jersey and provides a range of potential solutions to mitigate it in the future. The report is divided into three sections. This section provides background information about the New Jersey solar market. Section 2 defines solar market development volatility and reviews some of the drivers of this phenomenon both generally and specifically within the current New Jersey market. Section 3 includes a discussion of market and incentive program design strategies and provides several options for policies that could be implemented to alleviate potential future solar market volatility.

1.1 STUDY BACKGROUND AND SCOPE

In July of 2012, the General Assembly passed and Governor Christie signed S-1925 (Izzo, 2012). Known as the Solar Act of 2012, this comprehensive legislation made a number of changes to existing New Jersey solar market rules. Some of the most significant included:

- Substantially accelerating the near-term, annual SREC requirement on Load Serving Entities (LSEs),
- Providing the BPU with the discretion to approve solar projects on farmland (Subsection s),
- Developing a program to support the development of PV on brownfields (Subsection t),
- Creating a requirement that during the EY 2014-2016 period the BPU approve 80 MW of grid-supply capacity per year (Subsection q), and
- Defining an aggregated net metering option for public entities (New Jersey BPU, 2014).

In addition to these changes to the solar market regulatory structure, the legislation also required that:

“The board shall complete a proceeding to investigate approaches to mitigate solar development volatility and prepare and submit, pursuant to section 2 of P.L.1991, c.164 (C.52:14-19.1), a report to the Legislature, detailing its findings and recommendations. As part of the proceeding, the board shall evaluate other techniques used nationally and internationally.”

This report has been commissioned by the BPU Office of Clean Energy (OCE) in partial fulfillment of this requirement. The analysis and options detailed in this report are being provided to OCE for their consideration. Recommendations will be provided to the legislature by the BPU that will be informed by the analysis in this report.

The BPU plays multiple roles in New Jersey, with responsibilities for encouraging the development of clean energy technologies while also protecting ratepayers from undue price increases. The BPU OCE has previously enumerated a number of goals with respect to the use of ratepayer funds related to solar market development, including:

- ⦿ Sustained, orderly solar market development,
- ⦿ Ensuring goals are met at the least cost to ratepayers,
- ⦿ Creating a solar market that allows broad ratepayer participation,
- ⦿ Encouraging market transformation that transitions solar away from state incentives, and
- ⦿ Ensuring regulations are consistent with legislative frameworks and intents (Summit Blue Consulting & Rocky Mountain Institute, 2007).

These goals were used as the primary criteria to guide the development of this report.

This report examines previous solar market development volatility in New Jersey and provides a range of example policies and potential options for policymakers to consider to mitigate future volatility. Whereas the report does discuss policy evaluation criteria beyond market development volatility, it is not intended to provide a comprehensive or quantitative analysis of each policy evaluation criteria. A more in depth, quantitative evaluation of the potential policy options is beyond the limited scope of this report and should be conducted as part of any future efforts to design specific solar incentive programs.

1.2 THE NEW JERSEY SOLAR MARKET

New Jersey has one of the most active solar markets in the United States. According a recent report published by the Solar Energy Industry Association (SEIA), New Jersey had the fifth largest state market by capacity installed in the United States in 2013 and currently ranks third in cumulative installed capacity nationwide (SEIA, 2014a).¹ New Jersey's nationally significant solar market is supported by a number of state-level policies. These policies are reviewed below.

1.2.1 NEW JERSEY SOLAR MARKET STRUCTURE

The primary state incentive supporting the development of the New Jersey solar market is the solar set-aside in the state's renewable portfolio standard. Under this policy, load serving entities² are required to meet a portion of their total annual load from qualified in-state solar PV systems. The proportion increases annually based on a legislatively-established compliance schedule. Obligated entities comply with this requirement by purchasing and retiring solar renewable energy credits. The first iteration of this incentive policy was implemented in 2004 in an effort to promote a market-based incentive mechanism. In 2006 the BPU worked with stakeholders to further expand the program with the goal of implementing a

¹ The same report found New Jersey ranked first in distributed, non-utility solar installations.

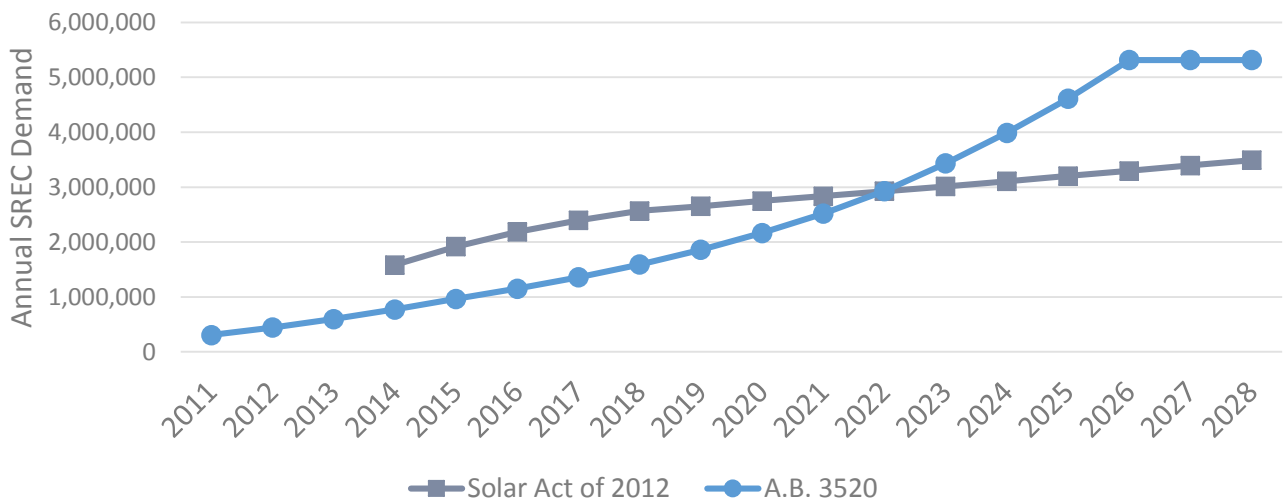
² Load serving entities are either third-party suppliers or basic generation service providers. Electric distribution companies do not have RPS obligations in New Jersey.

comprehensive incentive framework to transition the state away from solar rebates (New Jersey’s Clean Energy Program, 2006). This multi-year process ended with the closing of the last rebate programs in 2010 and the last new rebate commitments being made in January 2011.

1.2.1.1 Demand Schedule

Rapid price decreases in the global solar module market coupled with temporary enhancements to federal solar incentives³ and elevated SREC prices led to an unprecedented boom in solar development in New Jersey during the 2011-2012 compliance periods. This market growth resulted in an oversupply in the state’s SREC market which subsequently led to a decline in market development activity. In response to the fear of market stagnation resulting from this capacity overbuild, the legislature passed the Solar Act of 2012. This legislation made a number of adjustments to market rules and the RPS compliance schedule. It accelerated the RPS demand schedule in an effort to absorb surplus SREC supply, effectively doubling 2014 SREC demand. The goal of this legislation was to stabilize prices in the SREC market and prevent a substantial collapse in the state’s nascent solar industry. Under the new legislation, LSEs will be required to procure 4.1 percent of their total load from PV systems installed in New Jersey by 2028, a significant decline from the previous requirement of 5,316 GWh by energy year 2026 (equivalent to 6.3 percent of projected 2026 load).⁴ Figure 2 below shows the expected future SREC demand under the Solar Act of 2012 based on PJM’s most recent projected load growth (PJM Resource Adequacy Planning Department, 2014) along with the SREC demand schedule under the previous legislation. As the figure shows, the legislation also flattened the market demand schedule during the later years of the program.

Figure 2. Projected SREC Demand Under the Solar Act of 2012 and A.B. 3520



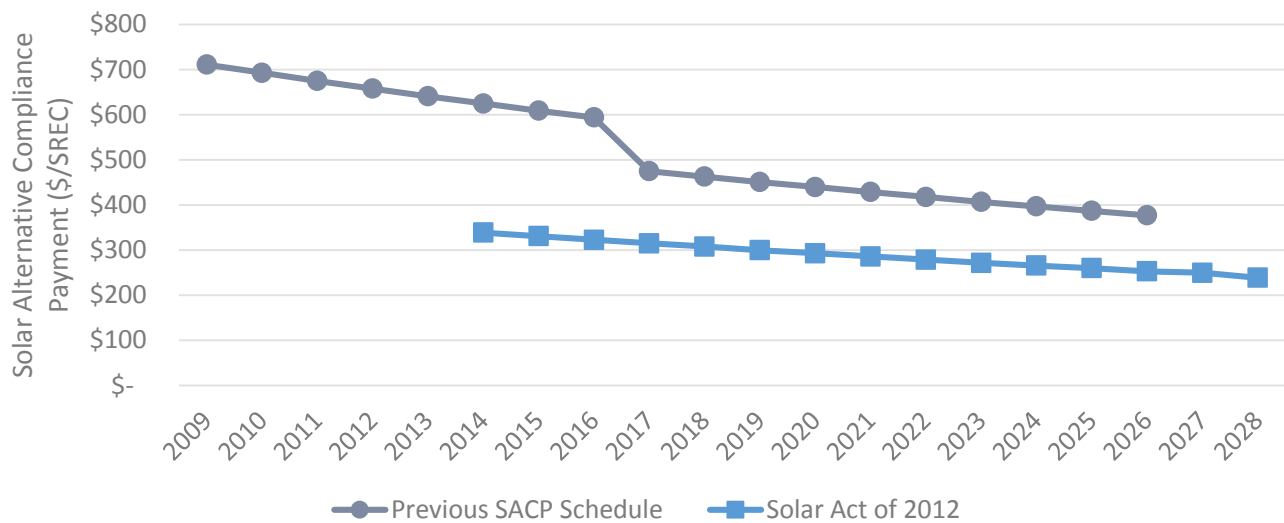
³ This includes the Section 1603 cash grant program and bonus depreciation.

⁴ The Solar Act changed the SREC requirement from a fixed volume target to a percentage of load target.

1.2.1.2 Solar Alternative Compliance Schedule

The solar alternative compliance payment (SACP) mechanism allows LSEs to make payments in lieu of retiring SRECs in order to meet their annual RPS compliance obligations. The SACP caps potential ratepayer costs and sets a maximum price for SRECs in the market. The Solar Act of 2012 reduced the SACP schedule to better reflect reduced solar installed costs and to protect ratepayers from excessive compliance costs. The revised SACP schedule is present below in Figure 3 along with the previous schedule.⁵ Commenters have noted that the relatively high SACP values in place before the Solar Act contributed to the rapid increase in installed capacity during the 2011-2012 period.

Figure 3. New Jersey Solar RPS Solar Alternative Compliance Payment Schedule



1.2.1.3 SREC Banking

The Solar Act also extended the banking life of SRECs, allowing them to be retired in the year they were produced and in the subsequent four years. This five-year shelf life is a two-year extension from the previous three-year shelf life. Importantly, unlike in some other markets,⁶ all market participants, from system owners to LSEs and brokers have the ability to bank SRECs in the New Jersey market.

1.2.1.4 Electric Distribution Company Solar Financing and Procurement Programs

In addition to the basic regulatory structure of the SREC market described above, New Jersey's four EDCs operate solar procurement and loan programs that provide long-term SREC price certainty for participating system owners. These programs operate within the overall SREC market structure, providing long-term

⁵ The previous SACP schedule was established through a 2007 BPU order as part of the solar market transition process. (N.J. BPU, 2007)

⁶ For example, in the NEPOOL Generation Information System (GIS), market participants cannot bank RECs beyond a current calendar year, and New England states only allow LSEs to bank surplus compliance. These restrictions were adopted as means to limit the potential for suppliers to exercise market power, as well as to utilize the GIS for purposes of RPS compliance and source disclosure.

incentive price certainty for a subset of PV system owners. These include the PSE&G Solar Loan program⁷ as well as the solicitation-based procurement programs supported by Atlantic City Electric (ACE), Jersey Central Power & Light (JCP&L) and Rockland Electric Company (RECO).⁸ In addition to these long-term contracting initiatives, PSE&G operates a direct ownership program known as Solar4All. Each of these initiatives has recently received regulatory authorization to continue through 2016, supporting the development of up to 225 MW (DC)⁹ of additional solar capacity during the 2014-2016 period. Table 1 below shows the potential capacity that these programs could support over this timeframe. These initiatives cover roughly one third of the projected annual incremental required capacity needed during this period based on the legislated SREC demand schedule. Each of these extended EDC programs have elements designed to mitigate their near term impact on the SREC market, such as the staged introduction of new capacity in the Solar4All Extension program, and the embargo until EY16 on the EDC's auctioning SRECs generated from newly awarded Purchase and Sale Agreements (PSAs) from the EDC long term contracting program into the LSE market.

Table 1. Annual Potential Contribution from EDC Solar Initiatives in MW
(State of New Jersey Board of Public Utilities, 2013)

	PSE&G Solar Loan	PSE&G Solar4All	EDC Auctions	Total
2014	32.5	0	27.5	60
2015	32.5	20	27.5	80
2016	32.5	25	27.5	85

⁷ This solar financing initiative is currently in its third iteration, known as Solar Loan III.

⁸ A formal evaluation of these programs was completed by the Rutgers Center for Energy, Economic and Environmental Policy in 2012 and provides a comprehensive background of the programs (Center for Energy, Economic and Environmental Policy, 2012).

⁹ Throughout this report PV capacity is reported in DC nameplate capacity.

SECTION 2 SOLAR MARKET DEVELOPMENT VOLATILITY

The section provides an overview of solar market development volatility, its definition, causes and mitigants in New Jersey. Past market performance is evaluated from both an aggregate and a sector-level perspective. Future potential volatility drivers are also reviewed.

2.1 SOLAR MARKET DEVELOPMENT VOLATILITY DEFINITION

While the Solar Act of 2012 called for the BPU to investigate solar market development volatility, no formal definition of this term was provided in the legislation. As part of the proceedings related to this inquiry, BPU staff collected stakeholder comments in early 2013 in order to develop a definition of solar market development volatility. Stakeholders engaged included the ratepayer advocate, solar developers, industry associations and SREC brokers. Individuals approached the question with differing perspectives, which resulted in both differing definitions of market development volatility as well as differing perceptions of previous market performance. Some of these diverse definitions of market development volatility included:

- Frequent and unexpected changes in market conditions that impact investment decisions and market entry,
- Variation in both overall installed capacity and market segment installed capacity over time, and
- Changes in installed capacity over time as well as changes in the ownership profile of installed systems over time.¹⁰

Given the lack of consensus on this topic, the authors have chosen to define solar market development volatility based on the plain language meaning of the term. For the purposes of this report, solar market development volatility is defined as significant and rapid changes in the rate of market capacity additions over time. Stakeholders are likely to differ on both the appropriate timeframe over which to evaluate volatility, and the magnitude of changes that could be described as volatile, based on their roles and perspectives in the market. For instance, installers may consider an average 39 percent quarter-over-quarter change in market activity as indicative of significant volatility given the business planning challenges such changes present.¹¹ Regulators may view the same data and note that multi-month moving averages

¹⁰ Stakeholders indicated that third-party finance for residential PV systems has grown rapidly over the last several years in New Jersey. This is consistent with national trends which have seen third-party finance become the dominant residential ownership model in many leading solar states. (Greentech Media, 2013)

¹¹ The *average* quarter-over-quarter change (either positive or negative) in market capacity additions in New Jersey between Q2 2009 and Q1 2014 was 39 percent. The quarter-over-quarter change in market capacity additions ranged between 100 percent and 1.4 percent over that period. For reference, California saw an average quarter-over-quarter

have remained above 10 MW per month over the course of the past several years, indicating limited market volatility. Both these interpretations are valid given the perspective of the market actor.

For the purposes of this report, the authors present analyses based on quarterly installation data. This timeframe is consistent with both common business reporting metrics and typical economic data reporting periods. If an overarching goal of the New Jersey solar incentive program is to create a robust and self-sufficient market that transitions from state-supported policies, then evaluating market activity using the same timeframes used to measure business and economic activity in other sectors will allow stakeholders to best evaluate market health compared to similar industries.¹²

A critical component of market development volatility includes changes within distinct market segments, in addition to overall market capacity additions. Additionally, SREC prices are a significant primary driver of market development activity. The following sections provides a review of data related to these market metrics.

2.2 NEW JERSEY SOLAR MARKET PERFORMANCE

The following sections review the development of the New Jersey market over time, examining changes to overall capacity build rate. This section also includes an analysis of changes in market composition and installation type. Data presented in this section is derived from the March 2014 New Jersey Solar Installation Summary Report.¹³ Information presented in this section is based on timing of administrative registration of PV systems and does not reflect commercial operations in-service dates. Stakeholders have noted that administrative factors may influence the timing of this reporting. Additionally, PV systems can take several months to several years to go from planning to full commercial operations. Given this, the data presented here represent the end point of a potentially lengthy process, and this time lag can make it difficult to draw definitive conclusions between market events and market capacity additions.

2.2.1 INSTALLATIONS OVER TIME

Figure 4 below shows the quarterly capacity additions in the New Jersey market between 2008 and the first quarter of 2014. As the figure shows, between 2009 and 2011 the New Jersey solar market saw sustained and robust growth supported by a combination of rebate programs and the RPS solar carve out. The

market capacity addition change of 26 percent over the same time period under the California Solar Initiative while Massachusetts had an average 66 percent change over the life of the SREC I program (Q2 2010 to Q4 2013).

¹² Future analysis could compare the solar market to a range of other industry types, from construction to the power sector or even consumer appliances. Given the diversity of the solar sector, no single industry is likely to be an ideal analogue, however comparing market performance against established industries could give stakeholders better context for evaluating solar industry performance.

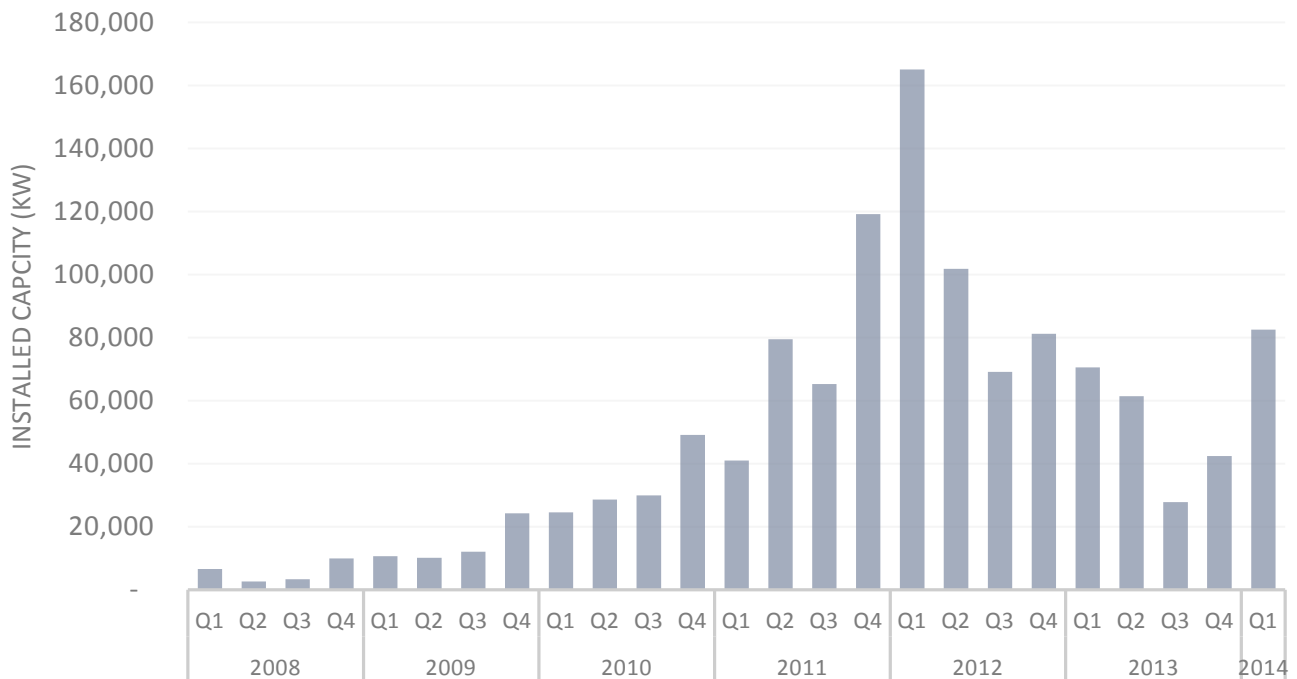
¹³ In this report, solar installation activity is deemed “complete” on the date the project is assigned an SREC Registration number by program administrative staff. This milestone can occur from 30 to 90 days after an individual installation commences commercial operations and becomes eligible to generate SRECs. As a result, reliance on SRP completions on a quarterly basis may overstate the extent of solar market volatility.

market saw a dramatic surge in development towards the end of 2011 and through the beginning months of 2012. Much of this increase was driven by the Federal 1603 cash grant program which provided solar system owners with cash in place of the traditional Federal Investment Tax Credit, high SACP values, and a decline in installed costs precipitated by changes to global module prices.

In early 2011, the global solar module market began to be significantly oversupplied as a result of major global capacity additions in both silicon production and module manufacturing. This oversupply led to dramatic declines in module costs. Module costs typically encompass between 35 and 40 percent of total solar project costs (Solar Buzz, 2012). Between Q4 2011 and Q4 2012 average prices for blended polysilicon modules declined by 41 percent (SEIA, 2013). Module prices have stabilized more recently, and in 2013 the U.S. solar market experienced the first year-to-year increase in module prices since 2008. However, these module costs increases were offset by cost reductions in other hardware components (SEIA, 2014b).

Following a steady decrease in quarterly installations in 2012, 2013 saw varying capacity additions on a quarter-to-quarter basis. During the third quarter of 2013, there were 27.8 MW of PV registered for the New Jersey SREC program, the lowest quarterly total since the first quarter of 2010. The market rebounded significantly in the first quarter of 2014 with more than 80 MW installed. Importantly, quarterly capacity additions show seasonal affects that should be considered when interpreting these trends, with the third quarter of the year tending to have reduced capacity additions compared to the preceding and following quarters. Similarly, the first and last quarters of several years in the data set were affected by expiration of federal incentives, which tends to boost capacity additions as developers attempt to meet incentive deadlines.

Figure 4. Quarterly New Jersey Solar Capacity Additions in kW (2008-Q1 2014)

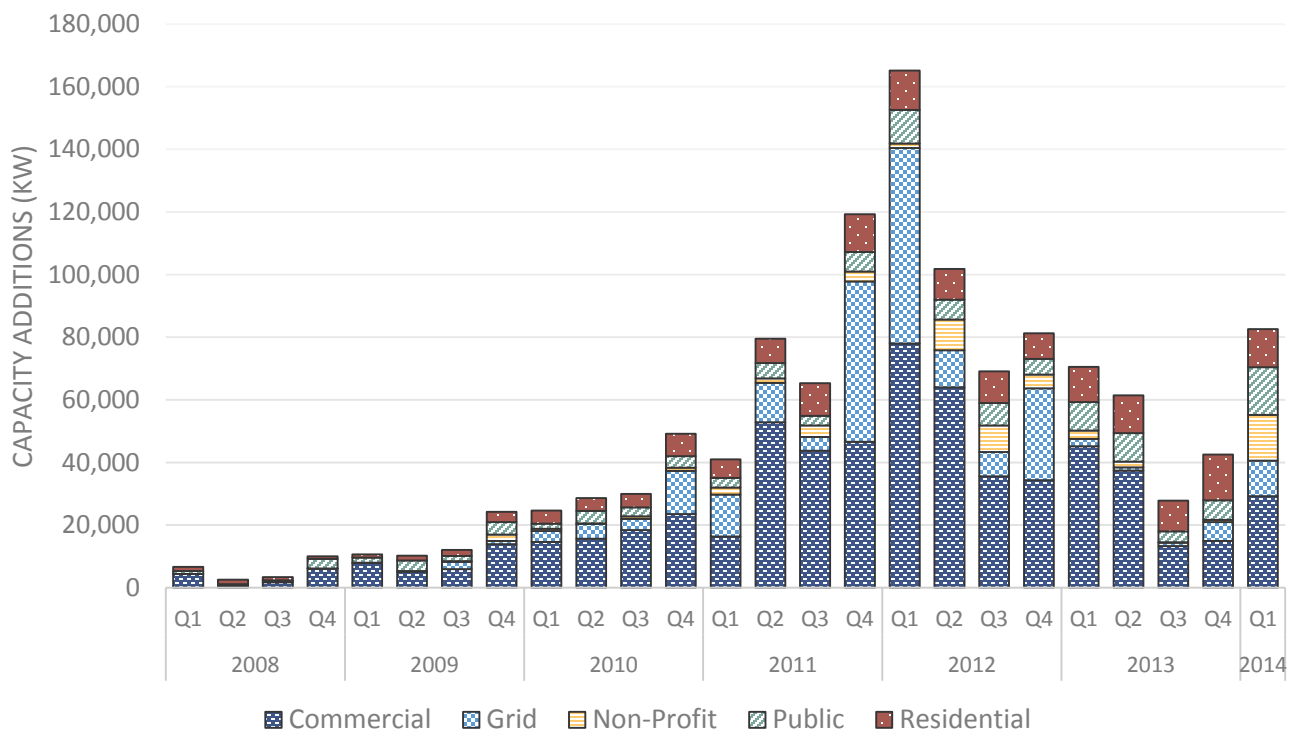


2.2.2 MARKET DIVERSITY

New Jersey has a broad solar market that supports a range of project types and sizes, from large ground-mounted, grid-supply¹⁴ systems to small, residential systems (both third-party owned and resident-owned). PV installation sizes range from a few kW to large multi-MW systems. In this section, development volatility of market sub-sectors is evaluated, and the evolution of sector-specific volatility is reviewed over time. Although an in-depth analysis of causality is beyond the scope of this report, looking at the data in this more granular manner shows some of the underlying drivers, or causes, of development volatility.

Figure 5 shows the quarterly capacity additions by market segment between 2008 and Q1 2014. Figure 6 shows the percentage of capacity additions for each installation type and Figure 7 shows quarterly capacity additions by system type relative to Q4 2013. The composition of the New Jersey market has changed considerably over time. Grid-supply projects have provided substantial capacity to the market on an inconsistent basis, particularly during Q4 2011 and Q1 2012, during the quarters with the largest state capacity additions.

Figure 5. Quarterly Capacity Additions in kW by Customer Type (2008-Q1 2014)



¹⁴ Grid-supply systems are PV systems that provide power directly to the grid instead of through a net metering arrangement.

Figure 6. Percentage of Total Quarterly Capacity Additions, by Customer Type (2008-Q1 2014)

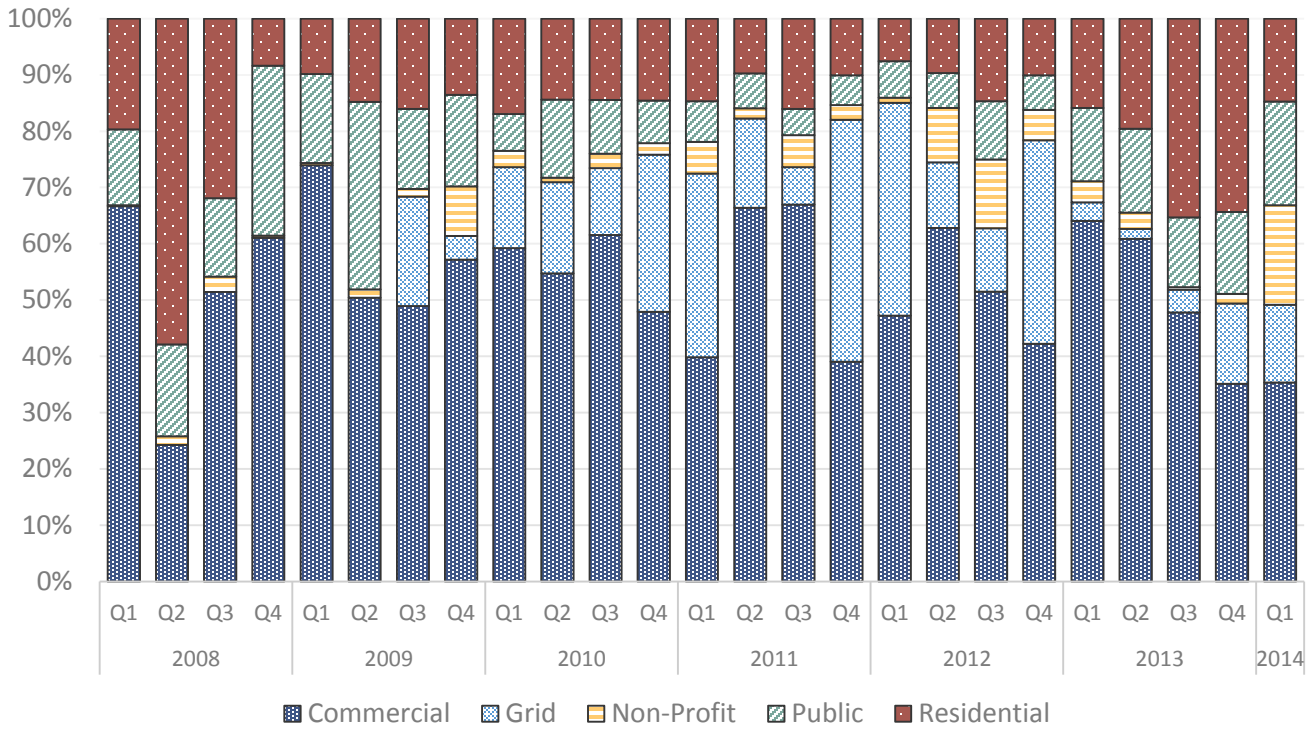


Figure 7. Quarterly Capacity Additions indexed to Q4 2013

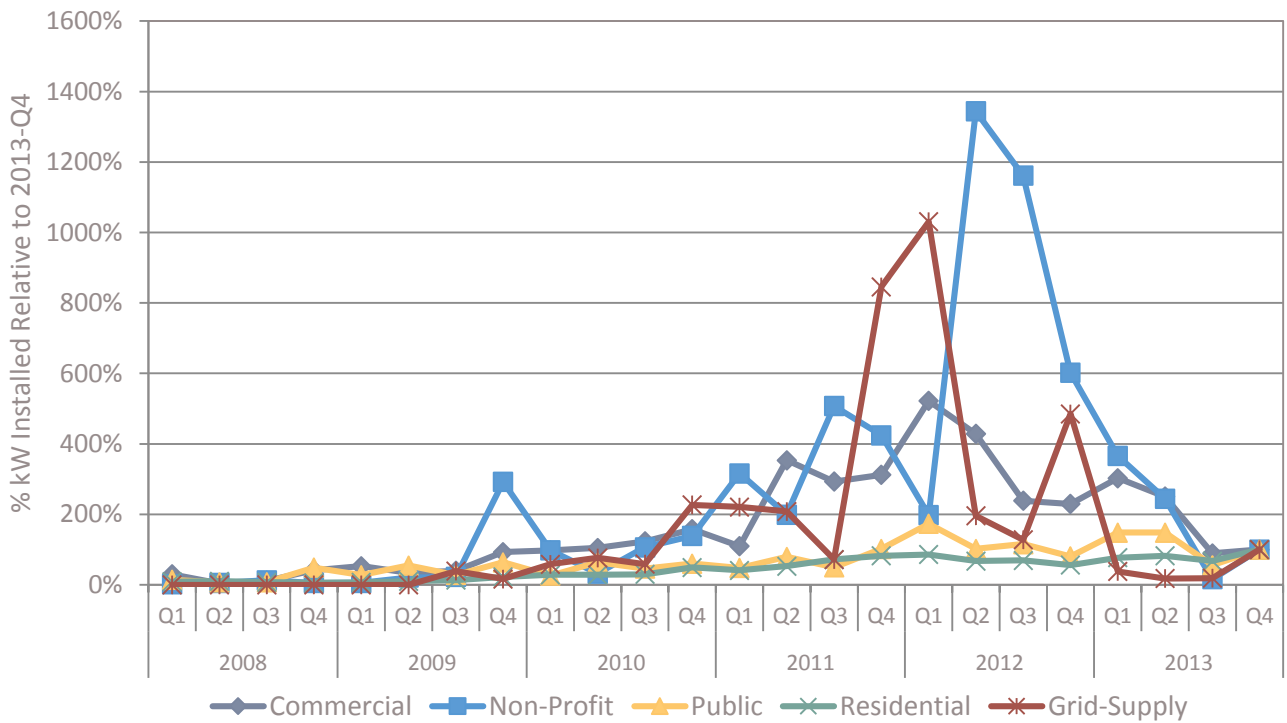


Table 2 below provides an analysis of market segment volatility. The table shows the average quarterly market additions for each market segment between 2008 and 2013. The standard deviation of these averages as well as the coefficient of variation is also shown.¹⁵ As the table indicates, the grid-supply and non-profit market segments have shown the most volatility over the analysis period with a coefficient of variation of 1.36, while the residential and public-sector market segments have been the most stable. Given the relatively small quarterly average market size of the non-profit segment, it is unlikely that this system type is a major driver of overall market volatility.

Table 2. Customer Type Quarterly Installation Volatility (2008-Q1 2014)

	Commercial	Grid	Non-Profit	Public	Residential
Average Quarterly Installations (kW)	25,176	12,836	2,402	4,691	6,768
Standard Deviation	21,178	17,545	2,573	2,795	4,455
Coefficient of Variation	0.84	1.37	1.07	0.60	0.66

A similar analysis was performed on the total number of systems installed within each market segment. Figure 8 and Figure 9 below show the absolute number of systems installed and the relative percentage of total systems by market segment over the course of the 2008 to Q1 2014 analysis period. Figure 10 shows the number of systems installed indexed to Q4 2013. As the data shows, residential systems have made up the majority of systems installed in New Jersey over the analysis period with a noticeable increase in the number of commercial systems during the period of highest market capacity additions in late 2011 and early 2012.

¹⁵ The coefficient of variation is the ratio of the standard deviation to the average. Higher coefficients of variation indicate greater variability in a data set.

Figure 8. Number of Installations by Customer Type (2008-Q1 2014)

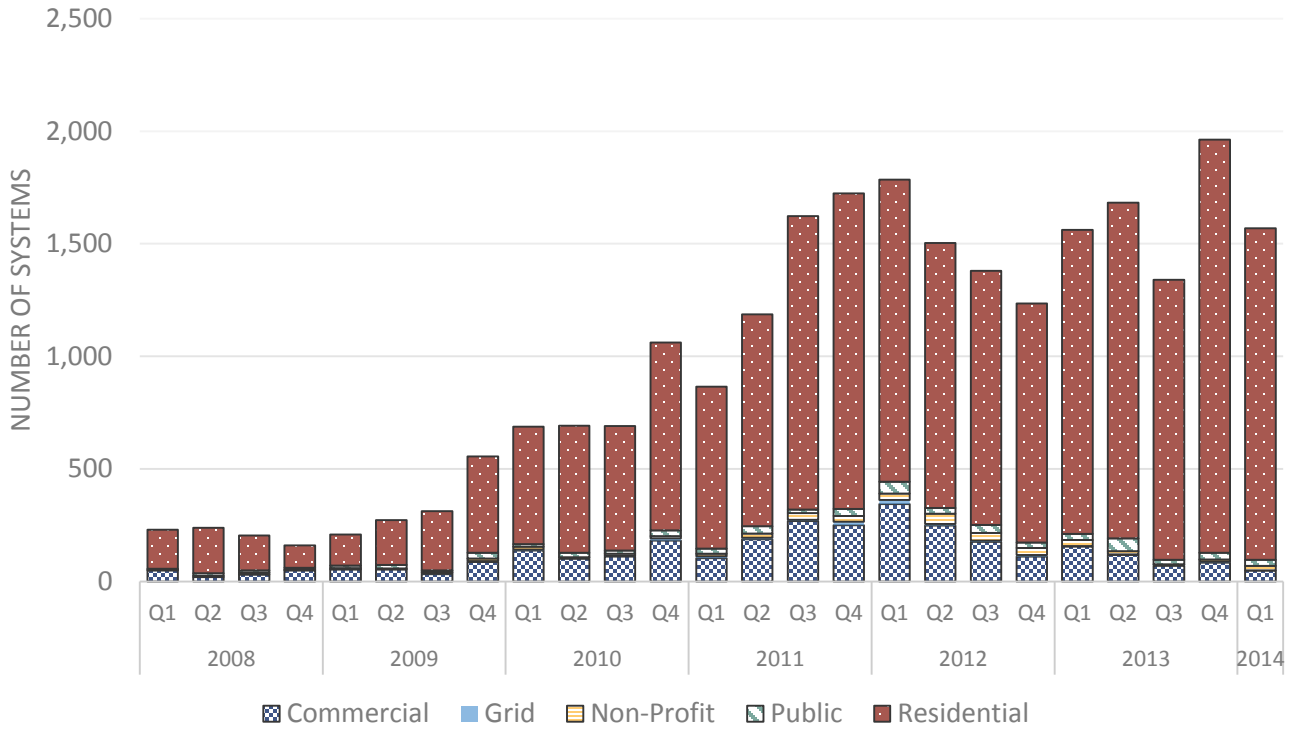


Figure 9. Percentage of Total Quarterly Installations by Customer Type (2008-Q1 2014)

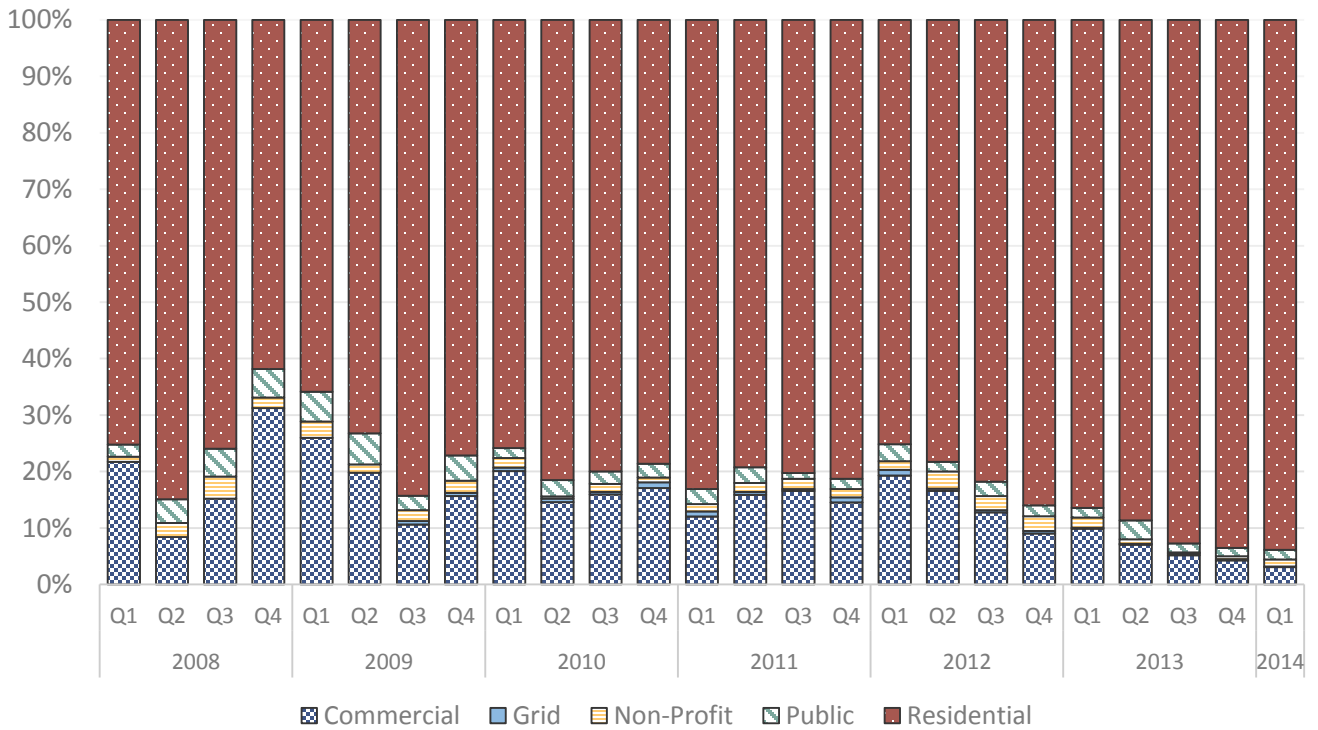
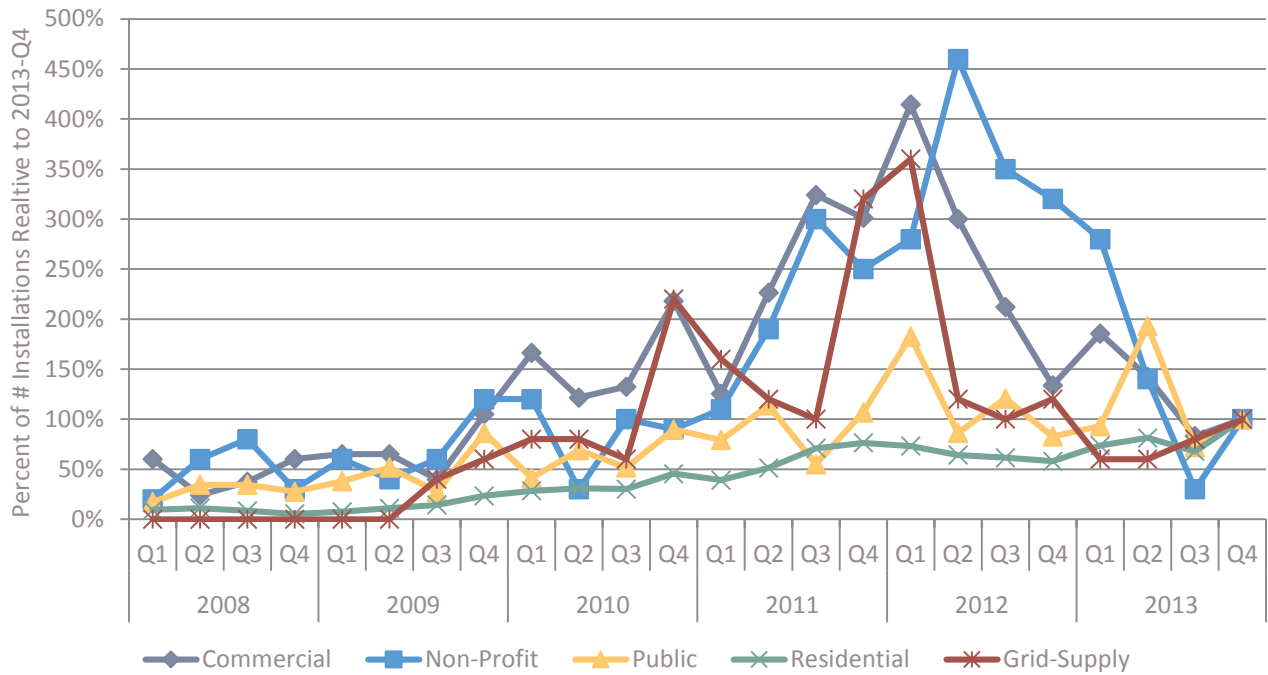


Figure 10. Number of Systems Installed Indexed to Q4 2013



Sector volatility can also be evaluated by examining system size rather than host type. In order to evaluate quarterly market volatility by system size, installations were grouped into eight size bins. Figure 11 and Figure 12 below show the quarterly capacity additions and relative percentage of quarterly capacity for these size bins between 2008 and 2013. Figure 13 shows capacity additions by system size indexed to Q4 2013. As would be expected from the preceding analyses, the largest project size bin encompassing systems greater than 2 MW show significant increases in quarterly additions during the period of highest overall market capacity additions (Q4 2011 through Q2 2012).

Figure 11. Quarterly Capacity Additions in kW by System Size (2008-Q1 2014)

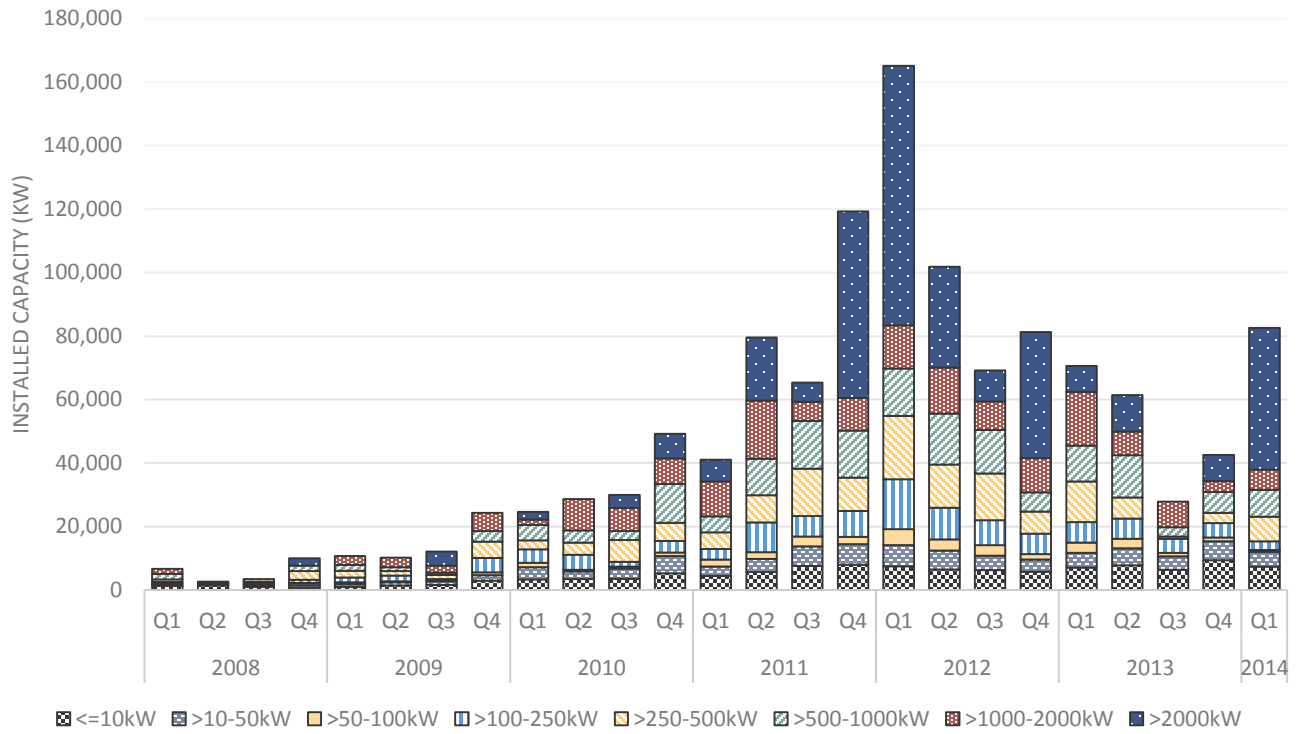


Figure 12. Percentage of Total Quarterly Capacity by System Size (2008-Q1 2014)

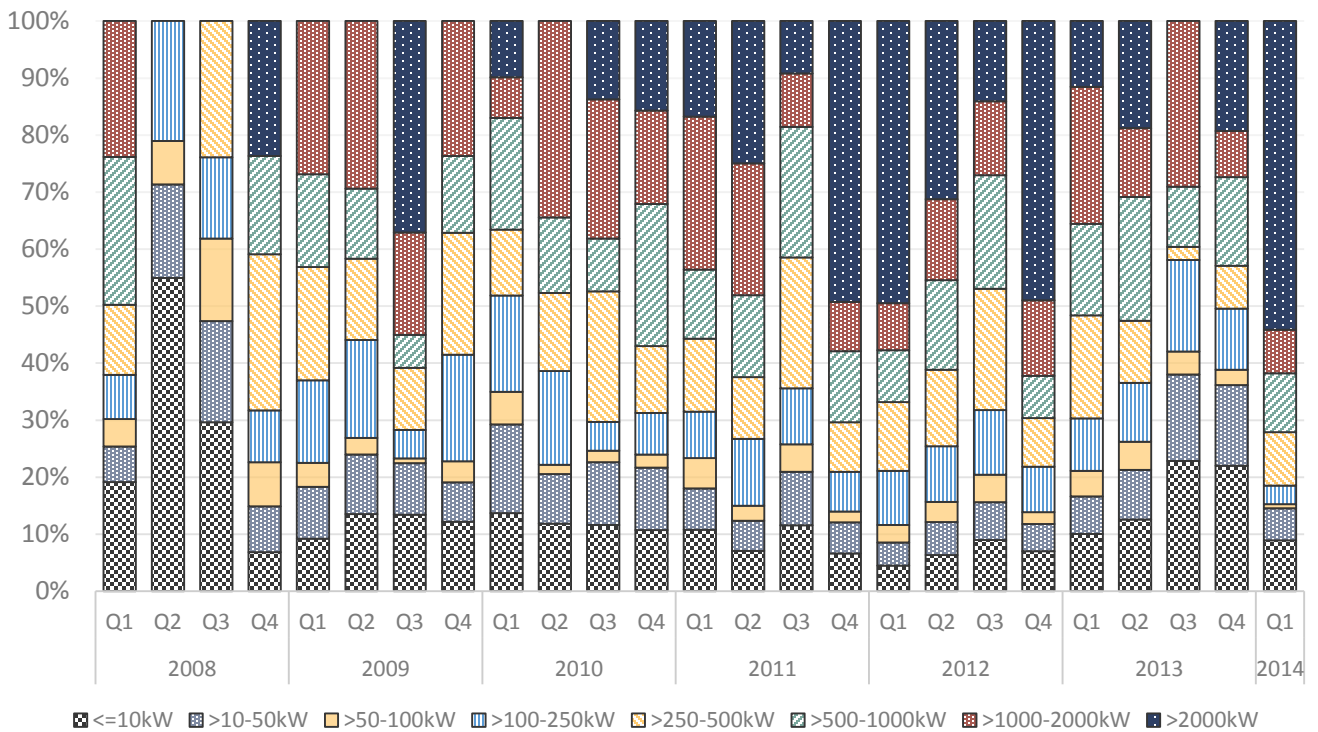
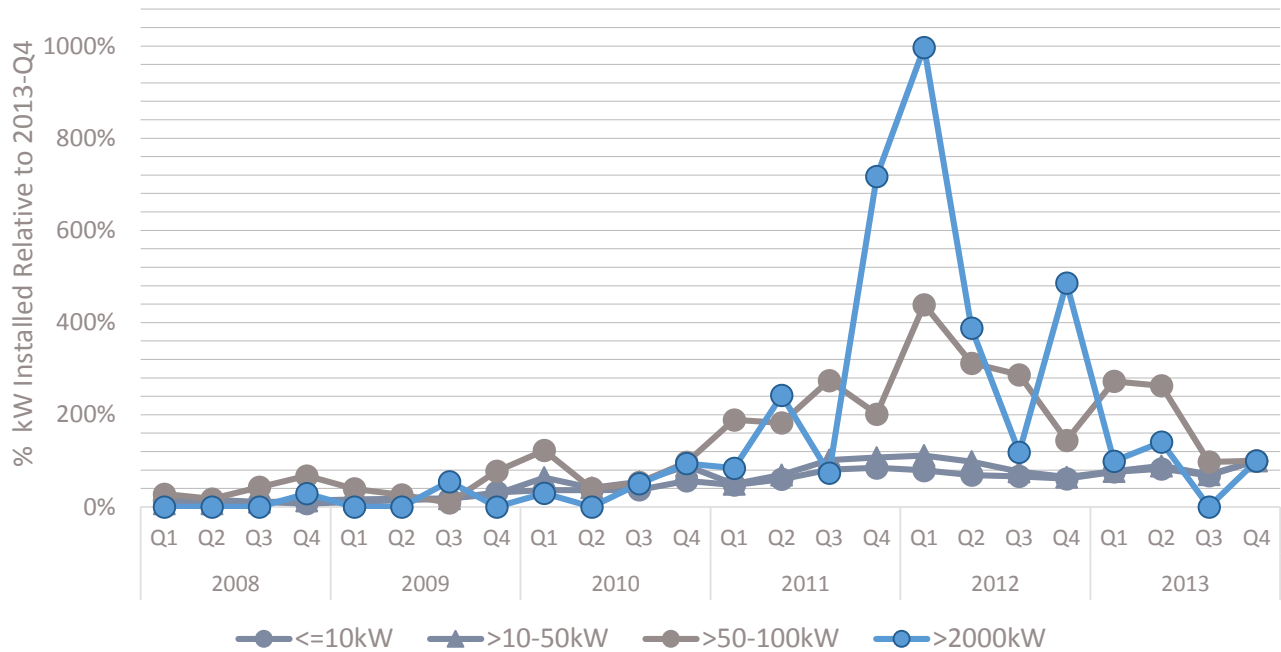


Figure 13. Total Capacity Additions by System Size Indexed to Q4 2013



A statistical analysis was performed to determine the volatility of quarterly capacity additions for each size bin over the course of 2008 to 2013. The results of this analysis are shown in Table 3 below. As the table shows, the largest size bin has both the largest average quarterly capacity installation during the analysis while also having the highest volatility as measured its coefficient of variation. The smallest system size bins (<=10kW and >10-50kW) and the >1,000-2,000kW size bins had the lowest volatility over the period. Although this analysis was not performed over subsets of the policy timeline, the mid-2011 through early 2013 period was the most volatile, with the period before and after this interval less volatile.

Table 3. System Size Quarterly Installation Volatility (2008-Q1 2014)

	<=10kW	>10-50kW	>50-100kW	>100-250kW	>250-500kW	>500-1,000kW	>1,000-2,000kW	>2,000kW
Average Quarterly Installations (kW)	4,645	3,513	1,581	4,671	6,639	7,553	8,105	20,482
Standard Deviation	2,691	2,149	1,335	3,731	5,432	5,520	4,919	22,968
Coefficient of Variation	0.58	0.61	0.84	0.80	0.82	0.73	0.61	1.12

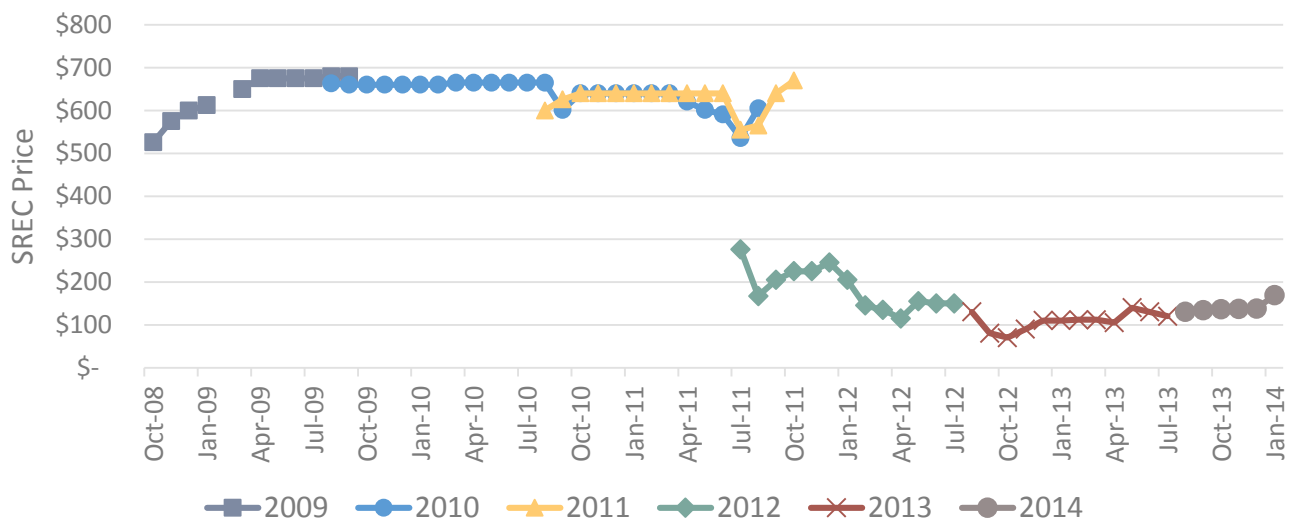
Segments within the New Jersey solar market have been highly volatile over time and this segment-level volatility has been significant driver of overall market development volatility. The period of aggressive capacity expansion in late 2011 and early 2012 saw both the commercial and grid-supply market rapidly expand. Similarly, larger systems were a major component of the overall market growth during this period. As the New Jersey market declined after this period, these two market segments saw a disproportionate

level of quarterly capacity contraction. Volatility in other major market sectors (residential and public) has been less of a driver of aggregate volatility over time. Additionally, the data suggests that market development volatility has decreased more recently. Implementation of Solar Act provisions that limit the development of large grid-supply projects may be a contributing factor to this recent market stability and are likely to reduce potential volatility potential going forward.

2.2.3 SREC PRICES

SREC purchases are private transactions, and limited information is available about the spot or term SREC transaction prices that LSEs and other market players pay for SRECs. The BPU publishes SREC transaction prices on its website, however this data provides a limited view of the market as it represents pricing drawn from self-reported transactions of various transaction durations and vintages as recorded in PJM-EIS GATS. Several brokerage firms provide platforms for New Jersey SREC transactions. One of these firms, SRECTrade, publishes clearing prices for its monthly New Jersey SREC auctions, providing a limited indicator of current SREC market conditions. This data does not take into account prices for long-term contracts, which may be lower than spot market prices, and does not include information about transaction volume relative to total market size. Figure 14 below shows the monthly clearing prices for New Jersey SREC vintages from 2009 to 2014.

Figure 14. Spot Market SREC Prices from SRECTrade Monthly Auctions (SRECTrade, 2014a)¹⁶



As the figure shows, SREC spot market prices remained above \$600 per MWh for most monthly auctions for 2009, 2010 and 2011 vintages. Prices for 2012, 2013 and 2014 SRECs have been significantly lower due to market over-supply conditions, reaching a low of around \$80 per SREC. SREC prices have increased

¹⁶ Note: This graph presents a limited view of SREC prices within the New Jersey market over time as it does not take into account contracted SREC transactions which may be lower than the prices listed as multi-year contracts tend to be priced at a discount to spot market prices.

since the third quarter of 2012 and are now being traded on the SRECTrade platform for around \$170 per MWh.

2.3 MARKET DEVELOPMENT VOLATILITY DRIVERS

Investor decisions to develop PV projects in the New Jersey solar market are based largely on expected solar project investment returns. If anticipated future returns are high given current and expected future market conditions, there will be many installations and market entrants. If expected returns are low, installations are more likely to slow. These changes in projected system investment returns are the primary factor driving solar market development volatility. Changes in expected system investment returns are influenced by a number of key factors including:

- Expected SREC price,
- Expected electricity value,
- System installed cost,
- Federal incentives,
- Previous market experience and perceptions of regulatory risk, and
- Opportunity costs for investments relative to alternative return opportunities.

The remainder of this section reviews elements of the current New Jersey solar market that influence expected investment returns thereby influencing solar market development volatility. During the course of the development of this report, discussions were conducted with a number of market participants and the comments provided to BPU as part of the solar market volatility proceedings were reviewed. Topics highlighted by stakeholders as major drivers of solar market development volatility are discussed in Section 2.3.1. Other potential market development volatility drivers are discussed in Section 2.3.2.

2.3.1 STAKEHOLDER IDENTIFIED SOLAR MARKET DEVELOPMENT VOLATILITY DRIVERS

The BPU OCE public stakeholder process collected comments from current solar market actors between January 7 and February 7, 2013. Additionally, several stakeholders were contacted as part of the development of this report. In order to preserve anonymity, stakeholder comments derived from individual interviews have been aggregated in this section.

Some stakeholders indicated that the Solar Act had alleviated many of the market's major structural challenges by increasing the legislative SREC demand schedule and expanding BPU discretion over the volume and pace of entry of grid-supply projects. Additionally, some stakeholders noted that installation rates for systems had remained above acceptable minimums over time and suggested that market volatility was not a significant concern going forward.

In contrast, other stakeholders expressed that there was still significant potential for market development volatility in the New Jersey market. Comments from these stakeholders tended to focus on four major potential drivers of future market development volatility:

- ⦿ SREC price volatility,
- ⦿ Long-term planning and contracting,
- ⦿ Market transparency, and/or
- ⦿ Regulatory stability and enabling environment.

A detailed discussion of each of these is provided below.

2.3.1.1 SREC Price Volatility

Some stakeholders identified variability in SREC prices as a major driver of potential market development volatility whereas others noted that SREC price fluctuations provide critical market signals that help prevent installation rates from significantly deviating from the RPS schedule. Several stakeholders indicated that if SREC prices remain within an “acceptable band”, this can serve to alleviate developer uncertainty and encourage orderly market development.¹⁷ During periods of SREC undersupply prior to the Solar Act, prices fluctuated substantially outside of this band, creating the potential for a development boom-bust cycle. The commenters’ consensus was that prices in the market appear to be stabilizing since the passage of the Solar Act, which increased near-term targets to partially absorb banked surplus SRECs, lowered the upper price-bound of the market through SACP schedule adjustments, and lengthened the banking life of SRECs. Some stakeholders noted that the current, relatively stable SREC market conditions could deteriorate after the banked supply had been exhausted, leading to an increase in SREC prices, substantial market development and a subsequent market slowdown.

2.3.1.2 Long-term SREC Contracts

Load serving entities have limited incentive to sign long-term contracts with SREC generators given future uncertainty related to their compliance obligations. In a diverse competitive retail electricity market, customer migration means LSE’s future load can be difficult to project beyond the currently contracted load, limiting the incentive to sign long-term SRECs contracts. Likewise, wholesale power marketers active in the basic generation service (BGS) market may have large and well-defined requirements over a 1- to 3-year period, with no certainty of securing a similar volume of BGS supply thereafter. Such market characteristics limit incentives to contract forward for a longer duration than current commitments. The reported unwillingness of LSEs to sign long-term contracts directly conflicts with typical project finance models, where developers are able to obtain long-term, low-cost bank debt based on production off-take contracts.¹⁸ Without long-term contracted revenues for SRECs, project developers have to rely on more

¹⁷ In public comments provided in early 2013, Alpha Inception suggested that an SREC price of \$180 per MWh was sufficient to create sustained orderly development.

¹⁸ While this general phenomenon is likely a factor for many LSEs, it is notable that several major LSEs and wholesalers in the market with sufficient capitalization have made direct solar project investments in order to meet future RPS obligations. Without significant research into the SREC procurement behavior of LSEs, much of this analysis must remain theoretical.

expensive forms and sources of capital, lower amounts of leverage, and/or higher debt-service coverage ratios, requiring higher overall SREC prices to meet investor target returns.¹⁹ Not having a substantial long-term forward SREC contract market in which to hedge SREC price risk leads to increased overall SREC price volatility in both the spot and short-term forward contract market, exacerbating project owner's expected return uncertainty.

If LSEs were contracting for a more significant portion of the future expected SREC requirements over the course of more than just several years, market development may more closely follow the legislated SREC compliance schedule, decreasing the opportunity for the market to be grossly over- or under-supplied, and reducing the potential for volatile boom-bust cycles. The creation of the EDC programs has helped provide long-term contracts in the market for some market segments, however the extent to which these programs crowd out other investments is unknown. Several stakeholders indicated that further expansion of the size of these programs, which have proven to be popular with market players, could further reduce SREC price uncertainty and therefore reduce development volatility.

2.3.1.3 Market Transparency

In general, market transparency is critical to the effective functioning of competitive markets. Potential developers make investment decisions based on their expected future returns which, in the New Jersey solar market, are driven by future SREC market dynamics. Therefore, accurate information about potential future supply and demand dynamics is critical to all market participants. Uncertainty or inaccurate information about future market conditions can drive both over- and under-investment relative to the RPS compliance schedule. The Solar Act increased market transparency by codifying reporting requirements for grid-supply systems, and creating limits on future annual grid-scale build rates. Stakeholders noted that improved information about the pipeline of potential projects has greatly increased the transparency of the grid-supply market, but currently available data sources provide less insight into behind-the-meter projects. This challenge is illustrated by capacity additions data from February 2014 in which several large behind-the-meter projects were installed resulting in a 44.1 MW monthly capacity addition. This capacity addition level is more than 2.8 times the average monthly capacity addition for the preceding three months. Unexpected large monthly capacity additions of this scale could significantly alter market dynamics, particularly during the latter part of this decade, when the legislated annual increase in SREC demand is relatively small. (See Section 2.3.2.2 below).

Stakeholders also indicated that there are still improvements that can be made to the available data. The disclosed pipeline data includes early-stage projects, many of which may drop-out of the development process. One stakeholder also suggested that BPU could make efforts to provide more timely and transparent data about SREC pricing.²⁰ There was consensus that improved price data and pipeline information could help further stabilize the market. In keeping with these comments, BPU has worked with

¹⁹ This observation is consistent with analysis conducted by some of this report's authors (Gifford et al., 2013).

²⁰ Providing price data beyond what is currently made available may be challenging as BPU has limited access to SREC transaction pricing.

the market manager to continually refine how data is made publicly available and has recently modified the format of its monthly data presentations.

2.3.1.4 Regulatory Stability

The Solar Act did alleviate SREC oversupply by advancing the demand schedule several years, it also indicated to stakeholders that the legislature was willing to intervene in the market by changing previously legislated demand schedules. Such interventions may help many market participants, but they also impact the value of existing investments, sometimes creating winners and losers. Given this experience, stakeholders may have reduced confidence in the long-term stability of the current market rules. Illustrating this, several stakeholders indicated expectations that the long-term demand schedule established by the legislature is likely to be revised in the future and that analysis of potential market dynamics in the latter part of the RPS schedule is not relevant given this expectation. If market actors are making decisions that significantly discount future policy stability, then they may be more inclined to make investment decisions that result in market capacity additions that do not track the legislated SREC demand schedule.²¹

Similarly, stakeholders noted that the potential for legislative changes to market demand may have been a factor in the rapid increase in capacity additions in late 2011 and early 2012. One market participant expressed concern that during this period some developers installed systems with increasing confidence that legislators would step in and adopt a new demand schedule in the event of a significant market oversupply. This further exacerbated oversupply conditions and created an increasing justification for new legislation. This dynamic highlights the challenges created when incentive policies are not perceived by market participants as fixed and stable.

2.3.2 OTHER VOLATILITY DRIVERS IN THE NEW JERSEY MARKET

The current New Jersey solar market has a number of other features that could drive future market development volatility. Some of these features relate to specific aspects of the New Jersey market while others are a more general function of the policy incentive mechanism New Jersey uses to incentivize solar development. Each of these issues is discussed in detail below.

2.3.2.1 Vertical Demand Curve

In a traditional market, demand curves slope downwards, meaning that the quantity demanded is a function of the price of a commodity. At higher prices, consumers are less inclined to purchase a product while at lower prices, consumption is increased. Under the New Jersey SREC market model, SREC demand is fixed based on the legislatively-established schedule and is not responsive to changes in market supply. Additionally, current SREC market supply is based on investment decisions that were made by individuals

²¹ Another consideration related to the issue of developers significantly discounting expected SREC revenues during the latter years of a system's 15-year SREC life is whether it is reasonable for ratepayers to continue to provide incentive payments to these systems if their owners made investment decisions assuming little or no SREC revenues during the final years of the system's SREC life. Bergek and Jacobsson have published an analysis of the potential for tradable certificate markets to generate economic rents for system owners that further explores this topic in the context of the Swedish tradable green certificate market (Bergek & Jacobsson, 2010).

months and sometimes years prior to the present, meaning that the overall level of current market supply is not a function of, or in direct response to, current SREC market prices. In a market without SREC banking, this vertical demand curve combined with non-price responsive supply can result in prices that are typically either very close to the ACP during periods of SREC shortage or near zero during period of SREC over-supply. Consequently, SREC market prices can be highly volatile, essentially functioning as an on-off switch for market development (Felder & Loxley, 2011). SREC banking can mitigate this volatility effect on SREC prices, however it does not fully mitigate the effect of fixed, annual vertical demand curves on market boom-bust cycles.

The use of a pre-determined annual vertical demand curve can lead to inherent market volatility. If during one year, project developers substantially over build the legislated target capacity additions, it may take several years of little or no additional capacity additions in order for demand to again match supply. As has happened in a number of SREC markets, periods of SREC over-supply can lead to legislative and regulatory intervention.²² In these instances, legislative or regulatory action effectively substitutes for a downward sloping demand curve, increasing market demand in response to lower SREC prices.

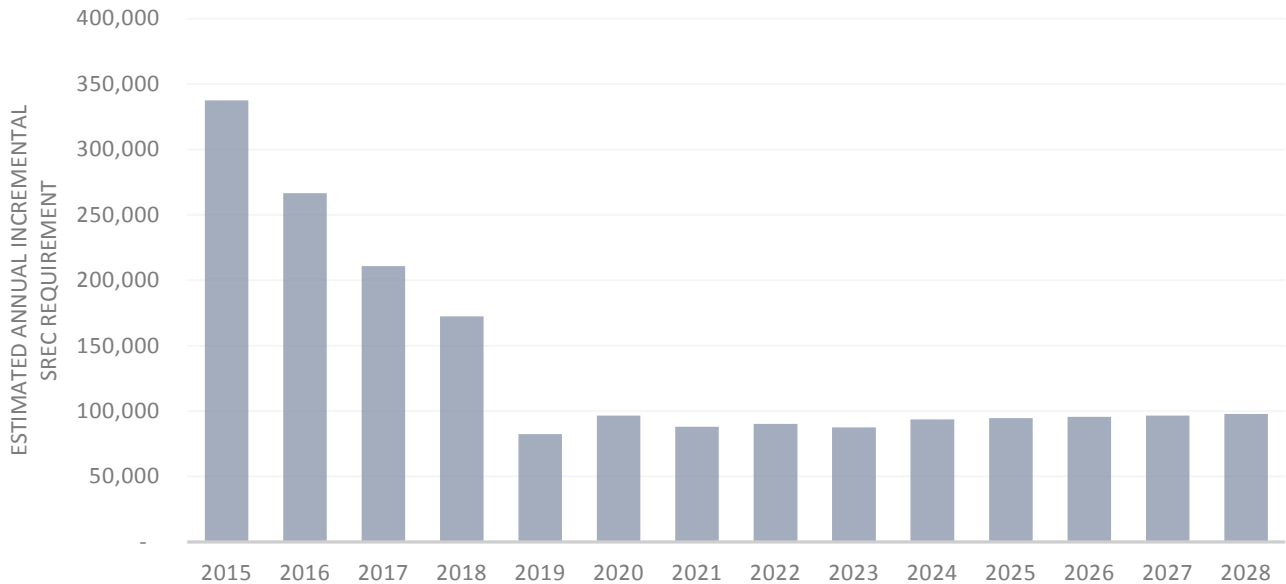
2.3.2.2 SREC Requirement Schedule

Legislatively established SREC requirement schedules can be a source of volatility for a number of reasons. The SREC compliance targets established under the Solar Act include several features that may contribute to future solar market development volatility. These factors are analyzed and discussed below.

New Jersey SREC requirements are calculated based on a percentage of state-wide load and the following analysis assumes that state load growth is consistent with projections from the PJM 2014 load forecast report (PJM Resource Adequacy Planning Department, 2014). Figure 15 below shows the expected annual incremental SRECs demand additions between 2015 and 2028. As the figure shows, the annual additional incremental SREC demand declines each year between 2015 and 2019, suggesting a legislatively-mandated contraction of annual market capacity additions. Stakeholders reported that the legislature established this declining schedule in part to reduce the total number of un-retired SRECs held in the market as a result of the significant growth in EY 2011 and EY 2012. Analysts at SREC brokerages have noted that SRECs banked over this period could be fully retired by 2016 (SRETrade, 2014a). Between EY 2019 and EY 2028, the legislated schedule defines annual incremental market additions that remain relatively flat, suggesting a solar market that is neither growing nor shrinking during this period.

²² Both Maryland and Massachusetts have seen recent changes to their solar program targets as a result of significant oversupply. Conversely, Pennsylvania has seen several years of low market SREC prices leading to limited market activity, which has not resulted in changes to the RPS requirements.

Figure 15. EY 2015-2028 Annual Estimated Incremental SREC Requirement

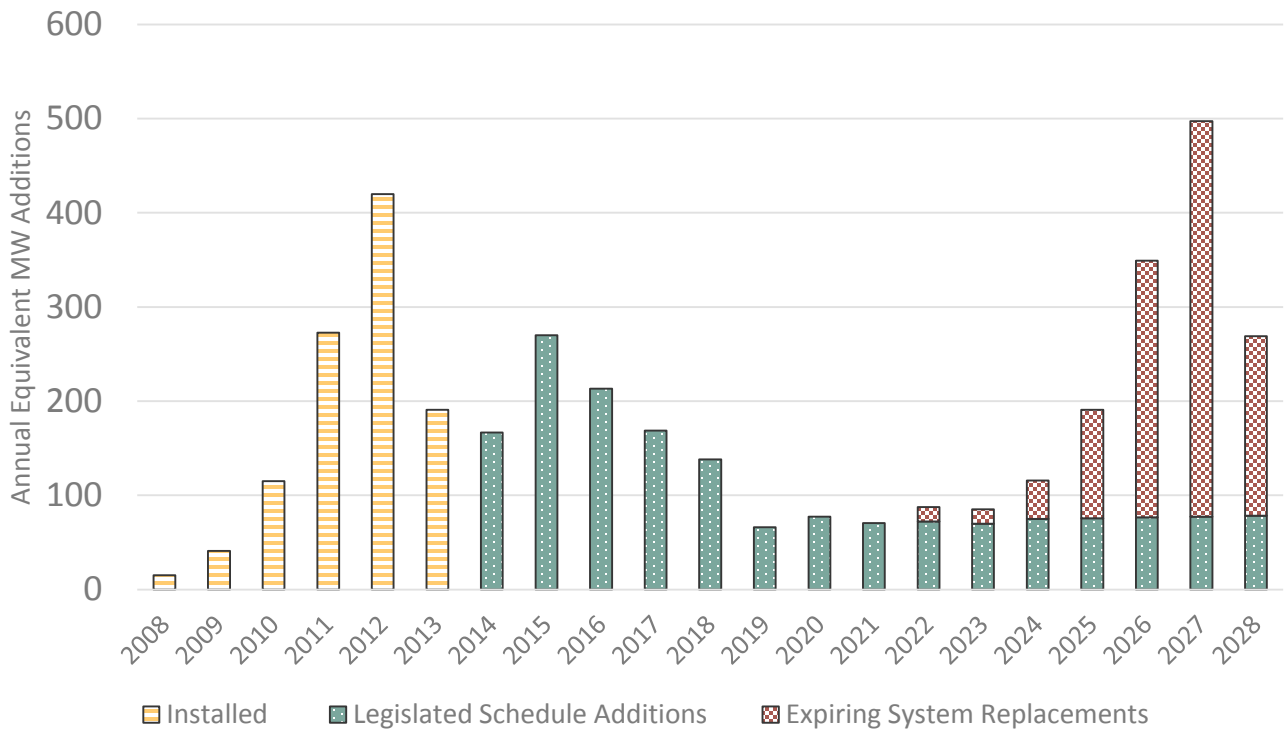


One important caveat to this observation is that the New Jersey RPS legislation puts a 15-year limit on a PV system’s SREC generation ability. This means that the SREC RPS obligation requires load serving entities to meet a portion of their load from PV systems in New Jersey that have been in operations for less than 15 years. This distinction is not a critical consideration for the early years of the SREC schedule in the Solar Act. However, this issue may affect the market during the later years of the current schedule. As systems lose their SREC eligibility after 15 years this capacity will need to be replaced by new installations.²³ Figure 13 below provides the authors’ estimate of the annual equivalent PV capacity additions required to meet both the incremental increases in the RPS requirement in the legislated compliance schedule and the incremental additions required to replace PV systems for which their 15-year SREC eligibility has expired.²⁴ As the figure shows, a majority of the projected incremental system additions after 2024 are driven by replacement of PV capacity that has lost its SREC eligibility rather than from incremental increases from the compliance schedule. These additions mirror the market additions from the EY 2008-2013 period, meaning that the erratic annual capacity additions from that time period could contribute to future market development volatility.

²³ Systems that have lost their SREC eligibility after 15 years are then eligible to participate in the main-tier RPS market)

²⁴ Annual equivalent capacity editions are the total capacity that would need to be installed on the first day of the compliance year in order to meet the legislated demand increase. Because capacity additions are made over the course of the year, the total capacity installed in order to meet the demand requirement will be either higher or lower than this value depending factors such as previously installed capacity, the monthly rate of capacity additions within the year, seasonal differences in production and the capacity factor of the installed systems.

Figure 16. Estimated Annual Equivalent Capacity Additions (MW) from Incremental Increases in SREC Demand²⁵



Several caveats should be noted about this figure. First, these calculations are based on installed PV systems that have a 13.7 percent capacity factor (1,200 kWh/kW). It is likely that capacity factors for PV systems installed in New Jersey will increase over time as technology improves, suggesting that the total MW needed to meet the incremental demand additions will be less than those forecasted in this figure. In addition, New Jersey law allows SRECs to be banked for a period of five years, meaning that developers may be able to anticipate the large incremental required capacity additions in the later years by building systems and banking SRECs for sale in future years, effectively smoothing out the buildout required to meet this erratic demand profile. Finally, banked SRECs will likely be used to satisfy a significant portion of the incremental increase in SREC demand in the 2014-2015 period (SRECTrade, 2014b).

Given the uncertainty surrounding expected gains in system efficiencies, and the banking strategies of future developers, it is difficult to develop a precise estimate of future solar market development over the course of the next 15 years. Nonetheless, the current market schedule does not establish targets that suggest sustained, orderly market growth. As seen in Figure 16, the market would be expected to see several years of decreasing year-over-year capacity additions, followed by a period of no sustained annual

²⁵ Note: the legislated schedule additions value for 2014 is the value of additional required capacity above the total capacity installed prior to EY 2014, not the additional capacity over the 2013 legislated demand.

market growth (EY 2019-2021), followed by a period of potentially erratic development largely driven by replacement of systems that are no longer eligible to generate SRECs.

In addition to the observation that the legislated incremental demand growth is either negative or stable during several of the compliance years, it is notable that equivalent capacity additions required to meet expected SREC demand for each year in the EY 2016-2025 period (maximum of 222MW) are below the actual capacity additions seen in EY 2011 (273MW). Given potential future advances in PV technology and further declines in installed costs, the currently legislated demand schedule may be a significant constraint on market growth if projects continue to rely on SREC incentives in the future. Alternatively, the market could progress to a point where SREC incentives are no longer necessary for developing PV systems in New Jersey. Under this scenario, market growth would be decoupled from the SREC demand schedule.

Finally, the small incremental annual increases in demand in the 2019-2023 period creates the potential for significant market development volatility as it would only take several large unexpected MW-scale projects to lead to multi-year oversupply conditions. Given the already low required annual build rates needed to meet the small incremental annual demand increases during this period, aggressive market build-out in one year may necessitate a significant decrease in future development for several years in order for demand to catch up with existing capacity. Under these conditions, legislators may again be faced with either allowing the solar market in New Jersey to collapse for several years, or further accelerating the demand schedule. Given the potential for the current SREC demand schedule to increase future solar market development volatility, legislators may wish to consider whether this schedule is consistent with the New Jersey's long-term solar market development goals.

The analysis in this section assumes that SREC revenues will continue to be a prerequisite for building solar systems in New Jersey over the life of the analysis. If system costs decline to a point where system owners are indifferent to SREC revenues, market development will be decoupled from the SREC demand schedule and development volatility would be de-linked from state incentive policies. It is possible this point could occur during the period analyzed in this section, however a quantitative scenario analysis of when PV systems installed in New Jersey could reach this point is beyond the scope of this report.

2.3.2.3 Federal ITC Expiration

Both the Federal Business Energy Investment Tax Credit (ITC) and the Residential Renewable Energy Tax Credit provide substantial support for PV systems installed in New Jersey (DSIRE, 2014). As currently legislated, the business ITC will decline from a 30 percent tax credit to a 10 percent tax credit after 2016. Similarly, the residential tax credit, which currently provides a 30 percent tax credit, will be eliminated after 2016 (U.S. IRC, 2007). Experience from New Jersey and other renewable energy markets has shown that the expiration of significant incentives can lead to rapid periods of market capacity additions in advance of the incentive deadline.²⁶ This dynamic could have significant effects on market development volatility in the

²⁶ This dynamic contributed to New Jersey market growth in 2011 and has also been seen in PV markets in Germany, Massachusetts and elsewhere. Additionally, this dynamic has been evident in the U.S. wind market where expiration of the federal production tax credit on several occasions has led to significant increases in market activity in advance of the deadline (Union of Concerned Scientists, 2014).

New Jersey solar market. Under this scenario, project developers facing a substantial decline in available federal incentives may be less concerned about future SREC market supply and demand dynamics leading to market capacity additions that deviate significantly from those required to meet the legislated demand schedule. This effect could lead to a market capacity over-build and an increase in banked credits in the market that might require several years of reduced market capacity additions in order to rebalance supply and demand. Under this scenario, policymakers may be faced with the choice of either accepting a collapse in the New Jersey solar installation market or accelerating the demand schedule once again.

2.4 VOLATILITY MITIGANTS IN THE NEW JERSEY SOLAR MARKET

The New Jersey solar market structure also has a number of features that help mitigate solar market development volatility. Several of these features are discussed below.

2.4.1 FUTURE CONSTRAINTS ON GRID-SUPPLY PROJECTS

A substantial portion of previous market volatility was driven by large, grid-supply projects coming on-line in order to benefit from high SREC prices and enhanced federal incentives (see Section 2.2). Due to their large relative size compared to the overall market demand, a limited number of large grid-supply projects can rapidly affect market supply and demand dynamics. Efforts undertaken by the BPU to limit future grid-supply projects as a result of the Solar Act will decrease the potential for these projects to drive market development volatility. As previously noted, large, behind-the-meter projects can have a similar effect on SREC market supply-demand dynamics, and (although more limited in their overall potential MW) these projects are not currently subject to the same restrictions as grid-supply projects.

2.4.2 HIGH RETAIL ELECTRICITY PRICES

Solar installations benefit from a number of potential revenue streams and incentives in addition to SREC sales. To the extent that these non-SREC revenues can support a substantial portion of a system's overall revenue requirement, the future expected value of SRECs become less critical to financing. At the moment, SREC sales are the most important revenue source for solar developers in New Jersey on a percentage basis, meaning that expected SREC revenues are the primary driver of solar installations in the state. New Jersey has some of the highest retail electricity prices in the United States, providing a significant source of revenue for behind-the-meter PV projects.²⁷ In the future, if the cost of PV installations continues to decline and retail electricity prices rise, it is conceivable that expected SREC revenues will be of reduced importance to developers looking to build solar projects. Should installed PV costs decline sufficiently and/or electricity

²⁷ Net metering provides a benefit to PV system owners, the cost of which is borne by other ratepayers. Recently, regulators, solar advocates and utilities have been increasingly focused on the revenue impacts net metering policies have across customer classes as solar PV penetration increases throughout the United States.

prices rise enough, this could lead to a market where part or even all of the solar project development is undertaken without material reliance on SREC revenue. Currently in California, residential PV systems are being installed without direct state incentives, benefiting only from federal tax benefits and the net metering value of generation (Munsell, 2013).

2.4.3 BASIC GENERATION SERVICE AUCTION

The Basic Generation Service (BGS) auction is the process by which the New Jersey EDCs procure energy for customers that have not chosen to switch to a competitive retail electric supplier. The BGS auction includes a requirement that tranche winners provide all-requirements retail service to default customers including solar RPS responsibilities. The BGS fixed-price auction is for three year tranches of supply on a rolling basis (with one third of the requirement bid out each year) while the BGS-CIEP market price is a one-year auction for the entire requirement (for larger customers). These auctions provide solar market participants with an opportunity to sell to winning BGS bidders who secure one-to-three year SREC contracts to match their BGS obligations. Data from January 2014 show that 83 percent of residential customer load is taking BGS service, while 34 percent of the commercial and industrial customer load is taking BGS service. Together, this represents roughly half of the state's total electricity load. The substantial state-wide supply under BGS contracts creates opportunities for multi-year SREC contracts that would not otherwise be available. This likely has a stabilizing effect on SREC market prices, further reducing potential market development volatility.

2.4.4 EDC FINANCING, PROCUREMENT AND DIRECT OWNERSHIP PROGRAMS

The New Jersey EDCs implement financing and long-term contracting programs that provide developers with future SREC price certainty. As previously described, these programs use competitive bidding processes to award long-term SREC contracts. The third round of the PSE&G solar loan program launched in late 2013 and the RECO, JCP&L and ACE programs were recently re-authorized by the BPU. Collectively, these programs represent a substantial fraction (roughly one third) of the overall expected future capacity additions in the state (See Section 1.2.1). By running regular procurements, these programs help to reduce market development volatility, stabilizing market capacity additions during periods of limited market activity.

In addition to the EDC contracting programs, the PSE&G direct ownership program also reduces potential slowdowns in market activity. By implementing a long-term program build-out, this initiative may be able to support the New Jersey solar market during periods of low market activity through planned, regular capacity additions. However, if not implemented in a coordinated manner, this program could also increase market oversupply. Because of this concern, the settlement that re-authorized this program in 2013, PSE&G agreed to delay implementation of this program to help alleviate SREC oversupply in the market. Similarly, the other EDC SREC finance programs have been designed to hold SRECs generated until EY 2016 should the market remain oversupplied.

SECTION 3 EXAMPLE INCENTIVE MODELS AND NEW JERSEY POLICY OPTIONS

This section provides an overview of policy options related to solar market development volatility. The first section defines a policy-type framework. The second section reviews and evaluates a series of policy examples drawn from stakeholder comments and research from national and international best practices. The final section provides a review of four policy options New Jersey policymakers and legislators could implement related to solar market development volatility.

3.1 INCENTIVE DESIGN MODELS AND SOLAR MARKET DEVELOPMENT VOLATILITY

Policymakers in different jurisdictions have developed a range of incentive program types. Some of these program types effectively reduce unintended solar market development volatility while others create open-ended incentives that can lead to extensive boom-bust market development. This section provides a brief review of incentive policy types and classifies them along a continuum of potential market development volatility. Policies discussed in this section are classified as either being capped-quantity policies, target-quantity policies or open-ended policies. These terms are defined and examples of each are given below.

Policy types described in this section are categorized using the following definitions.

- Capped-Quantity Policies: These policy types define a quantity of expected PV installations over time. Under these policies, market access is limited to systems that have received approval to take part in an incentive program.
- Target-Quantity Policies: Under these policy types, policymakers define a target quantity of PV development, but, unlike capped quantity policies, targets are not enforced and developers are free to enter the market without approval.
- Open-Ended Policies: Open ended policies are solar incentive programs that are offered without regard to particular market quantity limits.

Renewable energy incentive policies are diverse and some policy regimes may have elements of several of the policy categories listed above. For this reason, the categorizations listed below should be viewed as part of a continuum of potential policy types instead of as a strict typology of incentive programs.

3.1.1 CAPPED-QUANTITY POLICIES

Under capped-quantity incentive policies, project developers are awarded incentives through administrative applications or procurements. Developers who do not receive incentives are effectively unable to develop projects in the market. These policy types are characterized by substantially less solar market development volatility by restricting market access to available incentives. Several example policy types are described below.

3.1.1.1 Standard Offer and Upfront Payment Programs with Quantity or Incentive Caps

Under these program types, project developers typically access incentives on a first-come, first-served basis or via a lottery. Policymakers have the ability to control market development by establishing fixed schedules for incentive availability. These program types can be designed to give policymakers differing levels of control over solar market development rates. These options include:

- Program quantity or incentive limits without interim schedules. Under these programs, a program-wide incentive or capacity limit is established and developers can take advantage of the program on a first-come, first-served basis (or potentially based on a lottery mechanism). The program ends once the capacity limit is reached. This incentive design provides policymakers with some control over market development volatility (or maximum program size) by establishing an overall program goal, but induces limited control over system installation rates within the program. This design can be subject to unexpected, rapid system build-outs if incentive prices are not appropriately calibrated to PV system installed costs. Alternatively, if incentives are set too low the market development rate may be below policymakers intended market development rates.
- Program capacity or incentive limits with interim schedules. A variation on the incentive type discussed above involves time-based interim limits on incentive awards at regular intervals to prevent rapid and unexpected market development. An example of this program type is the Massachusetts Clean Energy Center's Commonwealth Solar II rebate program which currently offers limited incentive quantities in three-month blocks. Under this current structure, \$1.5 million is offered over a three-month period on a first-come, first-served basis (MassCEC, 2014). If funds are expended before the end of the three month period, applicants must wait for the opening of the next incentive block to apply for funds. If funds remain at the end to the three month period, those funds are rolled over into the next program block. Changes to rebate levels are made by regulators based on market conditions and program activity. Similar program designs have been used for standard offer contracts and California is currently implementing a price responsive version of this program model (See Section 3.2.2.3)
- Price-responsive capacity blocks without interim schedules. Incentive programs can be structured to adjust incentive levels based on program uptake rates, creating some regulatory control over market development volatility without establishing a prescribed market development schedule. The California Solar Initiative (CSI) is one such program. Under the CSI, each California investor owned utility has a capacity quantity limit for the program. A step-based, capacity-triggered, declining block schedule was developed at the start of the program. As rebates for each block were exhausted, the program stepped down to the next lower incentive tier. In parts of California, this declining block

structure has led to the development of a robust residential market which no longer relies on state-based incentives. While this program design provides some control over market development rates, the program was initially designed to last until 2016, but it has reached its capacity limit early due to unexpectedly strong demand, illustrating the market development uncertainty related to this approach (California Public Utilities Commission, 2014). This approach was similarly applied for a standard offer contract incentive in the CSI program.

3.1.1.2 Auctions and Other Procurements with Quantity or Incentive Caps

Auctions and other procurements for long-term contracts²⁸ are another policy type that provides regulators with substantial control over market development volatility. Under a typical procurement-based incentive regime, an awarding authority offers a fixed block of either capacity or total incentive funding through a competitive process. Procurement winners are awarded the right to develop their project and receive regular incentive payments. By conducting regular incentive procurements, awarding authorities can effectively define the rate of market development. This program type is currently being used in a number of jurisdictions including Connecticut, Delaware, and New York as well as through the current New Jersey EDC solicitation programs.

Capped-quantity incentive policies provide a number of benefits that help reduce solar market development volatility. These policy types can be highly diverse, and can involve a range of incentive types, from upfront payments and competitively procured long-term contracts to standard offer programs. Within these policy types, regulators and legislators can make policy choices that effectively eliminate market development volatility or have program mechanisms that simply limit potential volatility.

3.1.2 TARGET-QUANTITY POLICIES

Target quantity policies provide developers with open access to solar markets without firm policy-related quantity constraints on project development. The most notable target quantity policy type is the open market renewable portfolio standard that features a legislatively defined annual LSE procurement requirement. New Jersey's current solar incentive market structure, along with Ohio, Pennsylvania and Maryland, are typical examples of this policy type.

Under these policy types, an annual SREC quantity schedule is developed, typically through legislative action. Project developers enter the market with the expectation of selling SRECs into the market and evaluate future expected SREC market supply and demand dynamics and future prices as part of their investment decision making. Developers may be able to obtain multi-year contracts for some of their expected future SREC generation. However, SREC contracts that extend beyond several years are atypical given the high uncertainty of market dynamics and the small relative size of individual markets.

Because hundreds and potentially thousands of system developers are simultaneously and independently making investment decisions about installing systems without coordination, these program types can lead to significant periods of over- or under- supply. As previously described, the New Jersey market saw

²⁸ Auctions have also been implemented for upfront payments and other incentive types.

significant growth during EY 2011 and 2012 which caused the market to substantially overshoot the legislated demand schedule by several years. This over-supply led to a collapse in SREC prices and a subsequent decline in PV construction in New Jersey.

These policies create the opportunity for significantly more market development volatility than capped-quantity policies. Recognizing the challenges to creating a stable market environment that promotes sustained orderly growth, Massachusetts policymakers have implemented a solar RPS requirement that attempts to limit market development volatility by adjusting SREC demand based on current SREC supply conditions (a supply-responsive demand formula). The unique elements of this policy strategy are discussed further in Section 3.2.2.1 below.

3.1.3 OPEN-ENDED POLICIES

Open-ended policies are another option for program implementation. Under this policy type, incentives are available to project developers without programmatic limits or targets. Examples of this policy type include the Federal Investment Tax Credit (ITC), which currently provides a 30 percent tax credit for PV systems without an overall program cap.²⁹ Similarly, the German feed-in tariff (FIT) for solar PV installations provided long-term contracts to system owners without an overall program cap.³⁰ The effect of these policies on market volatility is highly dependent on how the incentive level is determined. For instance, an open ended incentive that does not adjust incentive levels based on market conditions can drive rapid increases in market capacity additions when system costs fall but incentive levels remain the same. Alternatively, programs that adjust incentive levels based on market prices (such as the ITC which provides its incentive based on a percentage of total investment) may contribute little to market development volatility assuming the policy remains stable.

Open-ended policies that result in increased costs to ratepayers or taxpayers are unlikely to be feasible for state-level incentive programs given current PV costs. However, in the future, it is conceivable that cost-neutral open-ended policies could be used to promote solar development. For instance, Minnesota is currently developing a 'value of solar tariff' (Minnesota Dept. of Commerce, 2014). This standard offer tariff is designed to provide a cost-neutral tariff rate to PV system owner and is calculated by netting all costs and benefits of PV system generation. In theory, an open-ended value of solar tariff could be implemented in which ratepayers and policy makers would be indifferent to the quantity of PV installed under the tariff. It remains to be seen whether the Minnesota value of solar tariff will result in significant PV market growth.

²⁹ While the ITC does not have an explicit quantity cap, the program is set to change considerably at the end of 2016, providing a time-based limit on the incentive.

³⁰ The most recent version of the German FIT law in 2012 specified that the FIT would transition to another form of policy support once the market reaches 52 GW of cumulative PV capacity. The structure of this new policy, however, has not yet been developed.

3.2 EXAMPLE POLICIES

This section reviews and evaluates illustrative short- and long-term policies. These policies represent alternative or complementary methods that might be applied to mitigate aspects of solar market development volatility. The listed examples were compiled from case studies, stakeholder comments, and the work of the project team. The following examples are evaluated using the OCE's existing policy evaluation criteria which guide its current regulatory involvement in New Jersey. These include:

- ⦿ Market stability,
- ⦿ Minimizing ratepayer costs,
- ⦿ Creating a diverse marketplace, open to participation from an array of ratepayer classes,
- ⦿ Long-term reductions in incentives leading to solar PV market transformation, and
- ⦿ Consistency with current legislative policies and structures.

The project team developed an evaluation matrix based on these five principles. Descriptions of proposed approaches are introduced below and accompanied by relevant examples from other jurisdictions where available. Each policy is evaluated based on its ability to support the criteria defined below. Additional categories were added to supplement the BPU criteria. The evaluation criteria are defined as:

- ⦿ **Market Development Stability:** This is defined a steady or stable quarterly market capacity growth rate. Target-quantity policies would be expected to have less stability while capped-quantity policies would have greater stability.
- ⦿ **Ratepayer Cost:** Defined as the relative cost imposed on ratepayers for a similar quantity of installed solar capacity.
- ⦿ **Ratepayer Cost Volatility:** This criteria evaluates whether the policy creates substantial variability in ratepayer costs over time.
- ⦿ **Implementation Feasibility:** This criteria evaluates how difficult implementation of the policy would be from a legislative or regulatory perspective and whether it is consistent with the current market framework. It also considers the relative likelihood of such changes being broadly acceptable to stakeholders.
- ⦿ **Market Diversity:** This evaluation criteria explores whether the policy supports a variety of supplier and host-project types, allowing both large and small firms and hosts to participate in the market.
- ⦿ **Long-term Incentive Reduction:** This criteria evaluates whether the recommendation encourages the market to move-away from incentives, or complements approaches to decrease reliance on incentives.

Policy criteria in this section are ranked on a one-to-ten scale, with one meaning the policy is least effective at achieving the objective and ten being the most effective. The analysis in this section provides a qualitative review of these evaluation criteria. A formal quantitative evaluation of specific policy options is beyond the scope of this report and should be conducted as part of any planning process that involves implementation of any of the policy options discussed below.

The table below summarizes how each example policy alternatives aligns with the evaluation criteria.

Table 4. Summary Evaluation of Example Policies

Policy Model	Minimize Market Development Volatility	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Maximize Market Diversity	Compatibility with Long-Term Incentive Reduction
Expand EDC Programs	5	1 to 4*	Unclear	10	3 to 7*	6
Green Bank Financing	2	5 to 7*	3	4	4 to 8*	5
SREC Price Floor	2 to 5*	3 to 6*	5	2	2 to 5*	3
Supply-Responsive Demand Formula	2 to 7 **	2 to 6*	4	2	2	3
Standard Offer Contracts	6 to 8*	4 to 6*	9	1	6 to 9*	8
Competitive Procurement	9*	5 to 9*	9	1	2 to 9***	9

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

** High end of range represents presence of gating mechanism on overall development volume as in Mass. SREC-II

***Low end of range has no differentiation; high end of range has highly differentiated auctions

3.2.1 SHORT-TERM POLICIES

Short-term policies are those that would likely require modest changes to the current New Jersey policy frameworks. These are each reviewed based on the policy evaluation framework listed above.

3.2.1.1 Expand the EDC Programs

New Jersey EDCs have developed several programs to facilitate the expansion of the solar market in order to support state-wide goals. These programs function to improve solar market accessibility by providing long-term financing and adding security to the development pipeline to achieve RPS and policy goals. Over the next three-to-five years, PSE&G will implement its expanded Solar4All and Solar Loan programs which are expected to support 142.5 MW of new capacity. New Jersey's other EDCs have three years to procure 82.5 MW for three market segments: landfill solar projects, 50 kW to 2 MW projects, and projects below 50 kW. A summary of each program type follows:

- Solar4All: Extended in May 2013, the Solar4All program allows PSE&G to directly own solar facilities on landfills and brownfields (42 MW) or at pilot sites (3 MW). During testimony to the BPU to extend the program, PSE&G argued that adding larger grid-scale projects added security to the development pipeline (State of New Jersey Board of Public Utilities, 2013). As part of the final BPU ruling, PSE&G will not begin construction under this program until 2015 in order to alleviate market over-supply conditions.
- Solar Loan III: Customers in the PSE&G territory building behind-the-meter solar projects are eligible for the Solar Loan III program. The program provides 10-year loans across four market segments: large non-residential (less than or equal to 250 MW), small non-residential (less than 150 kW), landfill and brownfield sites (less than 5 MW), or aggregated and disaggregated residential projects. Loans can be repaid through SRECs generated by the solar projects at a price determined through a competitive process. For each loan program solicitation, an SREC floor price is established for the duration of the loan (Weissman, 2013). Loans will be solicited every two months for the next three years until 97.5 MW of solar projects are funded.
- EDC Solicitation Programs: JCP&L, RECO and AE operate solicitation-based procurement programs that provide long-term SREC purchase contracts to winning bidder for a number of system size classifications. These programs were recently re-authorized by the BPU.

Stakeholders have expressed an interest in further expanding the size of the existing EDC programs as a method to strengthen the solar market. Further EDC project development could also create increased visibility into the solar development pipeline.

These programs can come at significant costs to ratepayers, who bear the administrative costs of these initiatives. Assessing the effects of further expansion of EDC programs is complex, and it is unclear how expanding these programs beyond their currently authorized size would benefit or harm the solar market. While these procurements could stimulate and stabilize development, they could alternatively come at the expense of further market development in other sectors, or lead to SREC oversupply if there is significant private development in the pipeline.

Policy Evaluation

Market Development Stability: If implemented in a manner that is sensitive to SREC market supply-demand dynamics--meaning both that solicitations are timed to account for expected market demand and SREC sales are timed to mitigate SREC price volatility--expansion of EDC solicitation and loan programs could assist in stabilizing solar market development by facilitating steady increases in installed capacity over time. Increasing the percentage of the market participating in the EDC programs would lead to a decrease in required installations from the non-EDC supported market. Ensuring that information about the development status of projects supported through the EDC programs is public and transparent would further support market stability. The size and roll-out schedule of an EDC program expansion would need to be carefully tailored to prevent exacerbating SREC oversupply, and resale of SRECs into the LSE market would need to be coordinated to prevent creating significant SREC market supply-demand imbalances.

Ratepayer Cost: EDC program expansion may come at a higher cost to ratepayers than further market development by other actors. The Solar Loan program and Solar4All programs have administrative cost-pass-through mechanisms which are assessed on the bills of all PSE&G customers. In an alternative scenario, such as private-development, this administrative cost pass-through would not occur. Similarly, the interest rates charged as part of the PSE&G loan program may be higher than would be available to some market participants on the open market, leading to higher loan repayment SREC bid prices. Finally, PSE&G receives a regulated rate of return, funded by ratepayers, on its Solar4All program.³¹

Additionally, EDC long-term contracts lock in SREC prices over multiple years, transferring market risk from system owners and to ratepayers. This risk transfer can lead to lower overall required SREC incentives for system owners due to lower financing costs achievable with greater revenue certainty, and therefore could result in lower overall ratepayer costs. The EDC program may also have the effect of lowering ratepayer cost by incentivizing capacity additions in the market during periods of over-supply, further suppressing SREC market prices. However, long-term contracts create risks that further technology cost declines may leave ratepayers overpaying for SRECs in the future.

Ratepayer Cost Volatility: It is unclear if ratepayer cost volatility would be impacted by expansion of the EDC programs compared to current policies.

Implementation Feasibility: The EDC programs could be expanded within the current policy and would be consistent with the existing incentive structure. The EDCs could petition the BPU for further program expansions as has been completed in the past for the Solar Loan I and II programs and other EDC financing

³¹ Several stakeholders have noted that SREC contract prices under the EDC financing programs have been above current market SREC prices and have concluded that these have resulted in overall ratepayer losses. Given available data, it is difficult to make a conclusion on the total costs to ratepayers related to these long-term contracts in part because the EDC programs have generated solar market activity that contributed to depressing SREC market prices, benefitting ratepayers. Any calculation of ratepayer impacts of the EDC programs would need to evaluate what market SREC prices would have been without the capacity editions from the EDC programs in order to draw definitive conclusions.

initiatives. That said, the EDCs have recently gained authorization from the BPU to continue the programs over the next several years, so further expansion of these programs may not be feasible in the near term.

Market Diversity: Further solar development through the EDC programs could crowd out development that does not fit within the categories defined through the EDC procurements. Alternatively, the EDC programs may be able to directly support market segments that are underserved in the open market.

Long-term incentive reduction: As an incentive program that provides support to lowest cost developers through a competitive process, the EDC financing initiatives should support reductions in state incentives over time.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Expand EDC Programs	5	1 to 4*	Unclear	10	3 to 7*	6

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.1.2 Green Bank Financing

Green banks use public-sector capital to encourage private-sector investment in clean energy projects. Smaller renewable energy projects, as well as those without long-term revenue certainty, have historically been underserved by private-sector debt finance. Currently, private-sector investors have been hesitant to offer low-interest or long-term financing options in the New Jersey solar market due to uncertainty related to project revenue, technology risk and high transaction costs. Inability to access financing increases overall project weighted-average capital costs and creates a barrier for market-entry.

State-level green banks can address these market barriers by implementing programs using public capital to encourage private-sector investment in solar markets. The goal of a green bank is to leverage private-sector capital in order to decrease project financing costs and lower incentive requirements over time. Green banks can be most effective by taking on or sharing risks that policymakers are more comfortable with than traditionally conservative lenders, ideally demonstrating through experience that risks are lower than perceived by those traditional lenders. Tools which have been utilized by green banks include: competitive loans, credit enhancement mechanisms, subordinated loans that occupy first-loss positions, and other low-interest financing options.

Implementation of green bank financing could help reduce solar costs in New Jersey by attracting long-term, low-cost debt to New Jersey solar projects. Green bank programs would have the effect of lowering overall required incentives leading to lower SREC market prices. It is conceivable that, if solar installation prices were to decline sufficiently and wholesale and retail electricity prices were to increase, green bank financing could provide substantial-enough support to some solar installations to eliminate their need for

SRECs entirely. Under this scenario, market development could be de-coupled from the SREC market, leading to lower solar market development volatility. Implementing a green bank would require initial capitalization of significant magnitude, and staff with significant financial and technology expertise in order to be effective.

Policy Examples: Connecticut and New York have both established green banks to support their clean energy sectors and Massachusetts is in the process of establishing a more limited solar financing initiative. Both Connecticut and New York created their green banks by using a legislative mandate to establish investment funds. Connecticut's green bank is a stand-alone entity, while New York's is housed within a division of NYSERDA.

Connecticut's Clean Energy Finance Investment Authority (CEFIA) has been able to leverage private dollars at an approximately 10-to-1 ratio for every public dollar spent (Metz, 2014). Existing programs include the Smart E-Loan program, the Solar Lease II program, and commercial property-assessed clean energy (PACE) financing. The Smart E-Loan program uses funds from the American Recovery and Reinvestment Act to create a loan-loss reserve fund to attract private-sector investment and extend low-interest, long-term financing to commercial and residential customers whose credit history would typically disqualify them from accessing debt. CEFIA's Smart E-Loan program provides access to a network of private-institutions across the state to compete to offer loan products. As of Q3 2013, twelve financial institutions were either in negotiations or confirmed to compete in the program (Garcia, 2013). CEFIA provides a similar service through its PACE program, where it provides technical underwriting and project evaluation expertise and contributes to program management, while approved private-sector providers compete to offer financing products for renewable energy and energy efficiency projects to customers (Clean Energy Finance and Investment Authority, 2013). Since the program's inception in 2012, approximately half of the projects funded have been for solar or combination solar and energy efficiency projects on commercial properties (Bailey, 2013). CEFIA's Solar Lease II program has also successfully leveraged over \$50 million in private capital using less than \$10 million in public funds ("CT creates \$60M solar lease program," 2013).

New York's green bank launched and capitalized an investment fund in December 2013. The bank has issued an RFP for finance institutions to propose partnership programs, which may include credit enhancement or warehousing loans for securitization (NYSERDA, 2014). The New York Green Bank has also proposed a solar loan program as part of its business plan which would allow the bank to take the first-loss position as a risk mitigant for other private sector investors (Booz & Co., 2013).

Additionally, the Massachusetts Department of Energy Resources (DOER) announced in its final SREC-II design that it intends to establish a programs aimed at supporting residential direct ownership. DOER plans to allocate \$30 million in ACP funds for the program, and hopes to leverage support from the banking sector in order to sustain the initiative as ACP collections diminish.

The aforementioned strategies and other financial mechanisms can address development volatility by decreasing financing risks. While these programs can supplement the market, they will likely be unable to bridge the gap that will open with the expiration of the investment tax credits for 2016 (Metz, 2014). Further market transformation efforts would be necessary to supplement the work of green banks in such a scenario.

Policy Evaluation

Market Development Stability: Increasing financing options through green bank support would provide or enable increased access to long-term, low-cost debt to solar project developers. The resulting improved project economics would increase the likelihood of development in the long-run. This policy option would also reduce the need for other state incentives, accelerating the transition away from SREC incentives and towards a market with a growth rate that is not defined by supply and demand dynamics of the SREC market. Reduced reliance on volatile SREC markets would be expected to smooth development volatility in the long run.

Ratepayer Cost: Successful state green banks should be able to leverage significant private capital from limited public-sector investments. If a state green bank was able to establish strong private-sector partnerships, it is likely that ratepayer costs would be reduced in the long-run. If programs had limited adoption, then ratepayer costs would remain minimally affected. However, the exact dynamics of this relationship would be determined by the origin and magnitude of the green bank's initial capitalization funding. If utilities were involved in the initial funding of green bank programs, some costs could be passed to ratepayers. Alternatively, if funding were through legislative appropriations, ratepayers would not bear any additional costs.

Ratepayer Cost Volatility: Reductions in SREC market prices due to lower SREC revenue requirements by solar developers would likely decrease ratepayer costs volatility, however the magnitude of this effect may be small relative to other policies discussed in this report.

Implementation Feasibility: New Jersey has experience creating special purpose investment funds. The New Jersey Environmental Infrastructure Trust has successfully provided low cost finance for public sector water quality infrastructure improvements since 1986. Community-development block grant funding was recently proposed to establish a resilience bank. Funding for solar energy is outside of the scope of this entity, but the policy framework used to create the resilience bank could be leveraged to create a green bank. Establishing a green bank may require new legislation and significant implementation lead-time, however it is consistent with the current market incentive model and would serve to complement current policies.

Market Diversity: Expansion of financing programs could increase market diversity by increasing the affordability of solar for a wider range of entities and, if part of the green bank's mission, by targeting sectors that are less effective at attracting capital. Green bank programs could also be developed in order to encourage direct ownership of systems over third-party ownership models, further diversifying the market. Conversely, if the green bank financing programs only served a narrow range of project types, this could lead to crowding out of other project types in the New Jersey market and decreased market diversity.

Long-term incentive reduction: If green banks are able to successfully encourage private-sector investment in the solar market, the incremental importance of other incentives would decline. Other market transformations would be necessary to completely reduce the reliance on incentives.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Green Bank Financing	2	5 to 7*	3	4	4 to 8*	5

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2 LONG-TERM POLICY EXAMPLES

Long-term policies are those that would require significant policy changes in the New Jersey solar market. Four long-term example policies are reviewed below.

3.2.2.1 Establish SREC Price Floor

Establishing an SREC price floor could mitigate the impact of boom-bust cycles on market participants by reducing SREC price variability. Depending on the mechanism used to establish the floor, a floor could be either a firm commitment by a buyer-of-last-resort to ensure price support, or a 'soft' floor that uses market mechanisms to support SREC prices during periods of over-supply. Price floors can provide revenue certainty, which in turn can reduce project cost of capital thereby lowering overall required incentives. A price floor could be implemented either by itself, or in combination with a supply-responsive demand formula as discussed below.

A variation of a price floor was discussed during the 2007 market transition proceedings. Under that model, the floor mechanism would have designated the New Jersey Economic Development Authority as the SREC market buyer-of-last-resort, providing long-term, fixed-price underwriting agreements for SRECs unable to be sold into the market. Evaluations of this model at the time cautioned that too high a floor could destabilize the market, driving over-investment. A price floor that was 60 percent of the SACP was suggested as appropriate to stimulate market development. Funds for the program would have been derived from ACP payments. An evaluation of this proposed model noted that the New Jersey Economic Development Authority would take on significant financial risk since funds would be tied to alternative compliance payments (Summit Blue Consulting & Rocky Mountain Institute, 2007).

During the recent solar market development volatility proceedings, one stakeholder suggested an alternative proposal to establish a soft price floor through the existing EDC SREC auction process. Under this model, rather than establishing a floor price for SRECs sold by project owners, it would instead create a floor resale price for EDCs intended to prevent SREC resales during times of surplus from suppressing price. If the price in the quarterly auction for EDC resale to the market of SRECs procured under the EDC financing program does not clear a pre-established floor price, the SRECs would be held in a containment

reserve and deferred to a later auction period. The reserved SRECs could be gradually reintroduced into the market during periods of SREC undersupply or after a fixed time period(s). Commenters suggested that this floor price would serve to protect ratepayer investments by preventing the EDC from selling SRECs at a significant loss.³² This model different from other market floor policies as it does not create a sale price floor for project owners, but instead creates a broader market price support mechanism.

Any floor policy would have to be implemented with caution. Should the New Jersey solar market progress such that the SREC price required to develop projects is below the established floor, the market would be over-subsidized potentially leading to capacity additions beyond those needed to keep the market in balance. There are many challenges to establishing a firm price floor price mechanism. A firm floor must be supported by a credit-worthy buyer with significant funding sources. Potential options include an EDC, which could ensure cost-recovery through ratepayers, or a government entity without significant budget constraints. ACP payments are also a potential funding source, but provide fluctuating revenues since payments are tied to market activity.³³ There is no guarantee that ACP funds would exceed floor payment obligations over the full compliance period, and (from a cash-flow perspective) a significant reserve would be required to allow such a funding source to be solvent at all times. Soft floor mechanisms, such as those in the Massachusetts SREC-I and SREC-II programs discussed in Section 3.2.2.12, or the potential mechanism implemented as part of the EDC financing programs described above, do not require stable funding mechanisms and may be more feasible options.

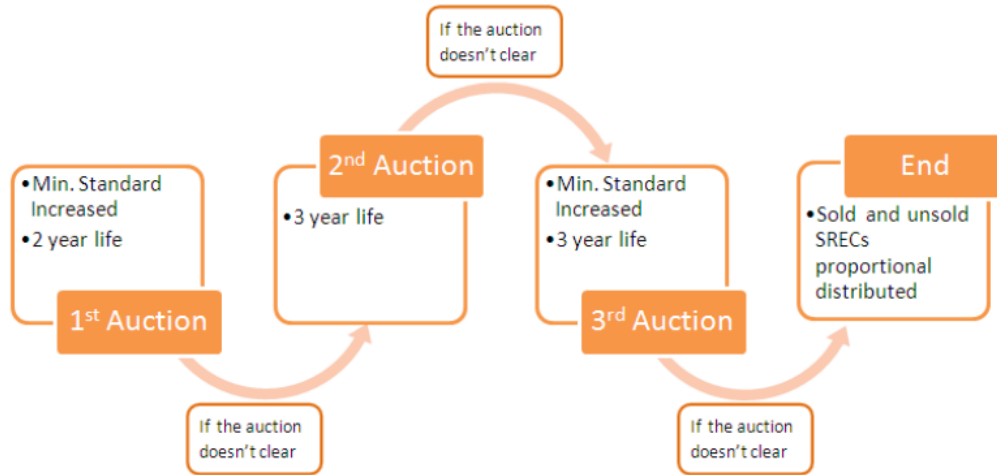
Example Policies: In Massachusetts, the SREC-I and SREC-II programs are supported by the Solar Credit Auction Clearinghouse, creating a soft SREC price floor. During periods of market over-supply, system owners can transfer unsold SRECs into a clearinghouse auction account at the end of the compliance year. Systems are provided with a 10-year period during which they can access the clearinghouse auction process. The auction is characterized as a fixed-price auction, where bidders offer quantities of SRECs they are willing to purchase rather than a purchase price. SRECs offered in the auction are sold at a pre-determined price of \$300/MWh.³⁴ The program design includes a series of iterative rounds intended to incentivize LSEs, or others, to purchase from this this auction. As shown in Figure 17 below, during successive rounds, if the auction has not cleared, the shelf-life of all 're-minted' SRECs is extended (the 'carrot') and future SREC obligations on LSEs are increased (the 'stick'). The combination of carrot and stick is designed to drive buyers into the market or face a sharply increased obligation likely to stimulate prices above the floor price. In the event that the auction does not clear, reminted SRECs could be sold in any of the successive three years. The potential cash flow lag before SREC revenues may be realized is one reason the floor is 'soft as the spot market price for SRECs often reflects a time-value-of-money discount to the floor price.

³² A full evaluation of this effect is beyond the scope of this report, however efforts to increase SREC market prices will have impacts on ratepayers, as the costs of LSE compliance will increase. This effect would decrease ratepayer benefit associated with EDCs holding SRECs until market conditions improved.

³³ Given current surplus market conditions, ACP payments are unlikely to be a near-term source of potential SREC floor funding.

³⁴ The auction process levies a five percent administrative fee, meaning that that net SREC sale value in the auction is \$285 per SREC.

Figure 17. Massachusetts SREC Price Support Auction Mechanism. (Judge, 2014)



Creating A Greener Energy Future For the Commonwealth



As the above description makes clear, the design of this mechanism is highly integrated with the supply-responsive demand schedule described in Section 3.2.2.2. The first clearinghouse auction was held in 2013 for SRECs generated during the 2012 compliance year. The auction saw limited interest from LSEs with only three of the 38,866 available SRECs offered in the auction were sold (DOER, 2013a).³⁵

Publicly available SREC pricing data suggests that this mechanism has not resulted in stable SREC-I market prices in excess of the \$285/MWh floor. So long as market entry remains open (i.e. prior to program caps being hit), prices can sink below the floor, for instance, when buyers expect that they can pay less than the floor in the future, due to the cost of new entry requiring prices less than the floor. However, in practice the mechanism has contributed to stabilizing prices. Even though market prices have declined below the floor, they have not collapsed, staying above about \$185/MWh at the bottom of the market and usually maintaining prices in the low to mid \$200s/MWh during periods of surplus. This experience, while limited, suggests that such an approach may contribute to market price stability by preventing sellers from taking price offers well below the floor.

Another floor price example is the Connecticut Class III REC market, which has both an ACP and a fixed price floor. The market is designed to support energy efficiency projects and combined heat and power

³⁵ In response to this, the DOER used alternative compliance payment funds to purchase SRECs from system owners.

development. The statute proclaims that prices shall not fall below \$10 MWh but provides no buyer of last resort. The RPS requirement for Class III generation has been fixed at 4 percent since 2010. Over half of the RECs in the market are provided by conservation programs, and as energy efficiency programs have continued to grow, the market has remained over-supplied. The price floor has prevented complete collapse of the Class III REC market prices. However, there is no buyer of last resort to support the price. As a result, many RECs remain unsold, and this is a function of the floor's design. Without a buyer of last resort able and willing to purchase all available RECs at the floor price, the floor only holds for a sub-set of REC sellers. For example, if market supply was double the obligation, half the RECs would be sold at the floor, and half remain unsold, with the *average* revenue being about half of the floor price, but with individual sellers realizing a higher or lower percentage of the floor price based on their success securing sales. CHP projects have had significant difficulty generating enough revenue to encourage further development in the market. It is difficult to evaluate the efficacy of the Connecticut price floor due to the severe supply-demand imbalance in the market, which will continue as long as the RPS target remains fixed (CEEEP, 2011). Stakeholder testimony has also criticized the limited enforcement of the legislated floor price (Allegretti, 2013). Due to the Class III REC market's inability to provide adequate revenue, many installations have been unable to monetize their RECs. In 2013, under Public Act 13-303, the state narrowed Class III eligibility,³⁶ temporarily pushing the market back into shortage. As additional supply responds to higher price signals the market could return to oversupply condition like those prior to PA 13-303.

Policy Evaluation

For purpose of this analysis, it is assumed that any price floor established is set below the expected level required to finance most new projects, thereby limiting, but not eliminating the ability of prices to fluctuate to convey market price signals. Further, it is assumed that any price floor mechanism includes a pathway to monetize all SRECs, as opposed to the price floor by decree model currently active in Connecticut.

Market Development Stability: The overall effect of the floor on development volatility would be highly dependent on the mechanism used. A firm price floor with a credit-worthy off-taker (such as an EDC) is more likely to be effective at encouraging market development during periods of over-supply than a soft price floor with limited credibility in the market. Depending on the policy approach and floor values, an SREC price floor that is available to all market participants could create conditions that significantly exacerbate SREC over-supply leading to market development that outpaces the legislatively established demand schedule. Given this concern, it may be appropriate to couple price floor policies with supply-responsive demand schedules to prevent significant SREC supply-demand imbalances. Even so, a price floor is more effective at removing the bust portion of a boom-bust cycle than preventing oversupply; and if a Massachusetts-like mechanism is used, as discussed in Section 3.2.2.12, without a complementary gating mechanism, a price floor is only moderately effective in stabilizing development volatility.

Ratepayer Cost: Relative to the current market structure, creating a price floor would lower developer SREC price risk, thereby lowering system costs of capital and overall required incentives. Introduction of a floor might be coupled, therefore with a drop in the SACP. A firm floor is expected to be more effective

³⁶ After January 1, 2014, no conservation and load management programs supported by ratepayers shall be considered Class III sources.

than a soft floor at reducing the cost of capital (DOER, 2013b). This affect could lead to lower overall policy implementation cost if the floor was established at a price that does not provide excessive returns to developers. In practice, administratively determining the proper floor level may be challenging as establishing a uniform floor price that encourages market development across a broad number of market sectors could lead to over-incentivizing lower-cost installations. In order to adapt to changing market conditions, the floor price would also need to adjust over time, adding complexity to the market. Because floor mechanisms transfer SREC market risk from project owners to other entities (potentially ratepayers), any floor policy should be explored in combination with policies that constrain developer’s ability to benefit from SREC prices significantly above the price floor.

Ratepayer Cost Volatility: Adding a price floor would reduce variations in SREC prices, and consequently reduce the magnitude of SREC price variability passed to ratepayers. Whether or not there was a mechanism within the policy design to stabilize the volume of SRECs would dictate whether overall ratepayer costs were stabilized.

Implementation Feasibility: The creation of a firm or soft price floor support mechanism would likely require additional legislative approval and development of a floor funding mechanism. LSEs would likely oppose a price floor and view such an intervention as anti-competitive. Any such mechanism would also require significant time and administrative cost investment to set and manage an appropriate floor price. A soft floor mechanism such as that established in Massachusetts also adds substantial complexity to the market. Despite these potential major implementation hurdles, this policy type would be consistent with the current New Jersey market incentive structure.

Market Diversity: The establishment of a floor would provide increased investor certainty, and likely encourage further solar development. It is unclear how the development would be distributed across size and ratepayer classes as the floor-price level could significantly influence market diversity. A floor that is differentiated by installation type could maintain current diversity, but would add substantial complexity.

Long-term Incentive Reduction: By having both a SACP and a floor, SREC market prices would be constrained within a narrower band. One expected result is a lower cost of capital and a commensurate lower cost required for market entry. While not necessary in this model, a floor price can be scheduled to decline in tandem with the SACP. The Solar Act established a declining SACP schedule, and thus a declining floor price could also support long-term incentive reduction. The Massachusetts SREC-II program model features a declining SACP and floor.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
SREC Price Floor	2 to 5*	3 to 6*	5	2	2 to 5*	3

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2.2 Supply-Responsive Demand Formula

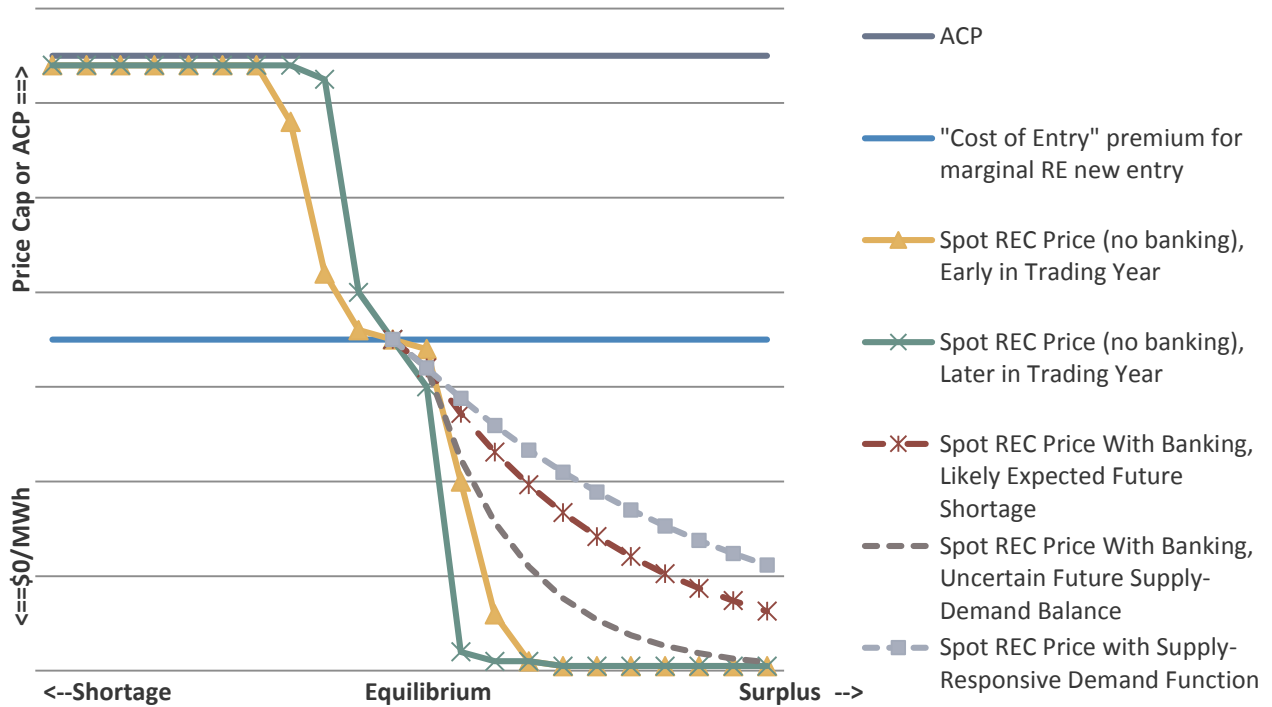
In New Jersey, LSE's annual SREC obligation is set at a fixed percentage predetermined by legislation. For the many reasons described in this paper, SREC market supply and demand can quickly become unbalanced. Under a shortage, SREC prices are high, and developers respond to those price signals, stimulating supply to better match demand. Experience has shown that markets can overreact to price signals and swing into substantial surplus. SREC surpluses can take years to abate, and the presence of banking – which serves to mitigate SREC price volatility – can extend the time period before supply and demand re-equilibrate. In the meantime, development activity must either decline materially, or risk further exacerbating surplus conditions. In the absence of banking, SREC markets create conditions for wildly volatile prices with relatively small changes in SREC supply leading to sharp changes in prices because market demand is fixed. SREC banking provisions can dampen SREC price swings by allowing market actors to sell SRECs over the course of several years.³⁷

A supply-responsive demand formula provides an alternative approach to mitigating SREC market price volatility (Felder & Loxley, 2011). Instead of establishing a firm requirement schedule (i.e. a vertical demand curve), a jurisdiction would establish a preliminary SREC demand target which is adjusted on an ongoing basis, using a formula that is a function of existing SREC supply and projected installation trends. The result of this mechanism is an SREC obligations that responds to supply changes and price signals. The response is somewhat delayed, and the parameters of the function can influence the responsiveness and time it takes to correct course.

In addition to bringing supply and demand back into equilibrium more quickly than would be the case with a static demand formula, SREC price swings would also be mitigated under supply-responsive demand policies. Figure 18 displays a schematic illustration of the impact of a supply-responsive demand formula on short-term SREC price. The supply-responsive demand formula is complementary to banking, and would serve to smooth out changes in SREC price with respect to supply during market surplus. As with supply and demand, beyond the current year, prices will return to equilibrium more quickly than under a fixed demand schedule in subsequent years.

³⁷ However, there are diminishing returns to extending allowed banking durations indefinitely, due both to the time value of money (discounting) and to cash flow constraints and aversion to the risk exposure associated with deferring the realization of revenue into an uncertain future when markets or policies could change.

Figure 18. Short-Term Relationship between Supply-Demand Balance and SREC Price under Different Policy Frameworks



Source: Sustainable Energy Advantage, LLC

Policy Example: The only known example of such a policy is the Massachusetts Solar Carve-out. The first iteration of this policy (SREC-I) was implemented to reach the state’s goal of installing 400MW of in-state PV capacity (a target later increased to a figure expected to be approximately 600 MW when finalized). This goal was reached in 2013 and, in April 2014, the state implemented a second program (SREC-II) that has a goal of increasing installations to a total of 1,600MW. These two programs have slightly different policy mechanisms. The SREC-II policy determines the LSE’s compliance obligation for a specific year based on a formula that includes the total expected generation, previously banked SRECs and volume adjustments from the price floor auction mechanism, amongst other factors.³⁸ Below is the compliance obligation formula for the Massachusetts SREC-II program:

³⁸ As previously mentioned, the Massachusetts SREC program includes a soft price floor mechanism that is intended to provide SREC market price stability. This mechanism is integral to the Massachusetts supply-responsive demand model and it is unclear whether a supply-responsive demand model could be developed without such a mechanism to support the acceleration of demand.

Total Compliance Obligation (Current Year)

$$\begin{aligned} &= [\text{Installed SREC- II Supply}] + [\text{Qualified but not installed SREC- II Supply}] \\ &+ [\text{Projected New Supply}] + [\text{Banked SREC- II Generation Attributes (CY- 2)}] \\ &+ [\text{Re- minted SREC- II Generation Attributes (CY- 2)}] \\ &+ [\text{Third Round Auction Volume Doubling (CY- 2)}]^{39} \end{aligned}$$

This mechanism allows Massachusetts to ramp-up or ramp-down the rate of increase in the state’s demand target based on recent installation trends and market conditions. It also contains a mechanism to encourage purchases in the state’s soft floor auction process by increasing SREC demand in future years when the auction does not clear.

A supply-responsive demand formula can at times overreact to market signals. This was observed in Massachusetts when the compliance obligation formula responded too slowly to the robust development pipeline in late 2011 and 2012. The 2012 SREC demand requirement stayed flat and then sharply ramped-up in the following years in response to accelerated market growth. The table below illustrates the annual SREC requirement in Massachusetts during the first five years of this program. This uneven market demand growth schedule creates challenges for LSEs attempting to plan for their future SREC obligations in pricing multi-year offers to retail customers, as it undermines their ability to project and hedge their costs.⁴⁰

Table 5. Annual SREC Requirement in Massachusetts 2010-2014 (DOER, 2014)

Year	SREC Requirement	Percentage of Load
2010	34,164	0.0679%
2011	78,577	0.1627%
2012	81,559	0.1630%
2013	189,297	0.3833%
2014	464,520	0.9481%

³⁹ The compliance obligation for the SREC-I program was calculated as:

$$\begin{aligned} &\textit{Total Compliance Obligation (Current Year)} \\ &= [\textit{Compliance Obligation CY- 1}] \\ &+ ([\textit{Projected SRECs Generated CY- 1}] - [\textit{Total SRECs Generated (CY- 2)}] \times 1.3) \\ &- [\textit{ACP Volume(CY- 2)}] + [\textit{Banked Volume (CY- 2)}] + [\textit{Auction Volume (CY- 2)}] \end{aligned}$$

And the total annual SREC requirement for the SREC-I program after the close of the program to new capacity is calculated as:

$$\begin{aligned} &\textit{Total Compliance Obligation (Current Year)} \\ &= [\textit{Total Projected SRECs Generated (CY- 1)}] - [\textit{ACP Volume(CY- 2)}] \\ &+ [\textit{Auction Volume (CY- 2)}] \end{aligned}$$

⁴⁰ Like New Jersey, Massachusetts has a broad range of competitive retail electricity suppliers. These suppliers are the obligated entities under the RPS.

One characteristics of the initial Massachusetts approach to such a formula is that it may result (and in fact is likely to result) in the ultimate targets being reached more quickly than under the schedule without the demand acceleration components. To improve the responsiveness of the formula to market signals and trends, and to increase market development stability, Massachusetts implemented a compliance obligation formula for the SREC-II program which will be calculated based on both actual and projected supply, where supply will be constrained by cumulative installed capacity targets. In order to accomplish this, Massachusetts has created a "Managed Growth" market segment for large, ground mounted systems. Total annual capacity in this market segment will be limited to the total expected MW needed to meet the state's overall target market capacity minus expected installations in other market segments.

Policy Evaluation

Market Development Stability: Allowing SREC demand to react to supply would mitigate SREC oversupply, stabilize overall installation growth and reduce SREC price volatility.⁴¹ A responsive demand model (with or without an auction mechanism) can react to unforeseeable market factors in a more real-time manner and correct any supply-demand imbalance as the program proceeds. As observed in the Massachusetts SREC-I market, the supply-responsive demand formula does not always react quickly enough to rapidly changing market dynamics. The Massachusetts SREC-I compliance obligation formula, which accounts for historic compliance obligation and market signals, proved to be insufficiently responsive during the supply spike in late 2011 and 2012. The model resulted in sharp changes in the SREC demand schedule, and the ultimate targets being reached more rapidly. Additionally, the Massachusetts market has had recent market development volatility related to the expiration of the first SREC program as developers have rushed to build projects under the more lucrative phase I program. Massachusetts' new SREC-II formula has made a number of changes that include an improved and more flexible formula that accounts for existing market conditions as well as projected installation trends and overlays a gating mechanism for market entry that was created to stabilize overall solar market development volatility. This gating mechanism will likely improve the ability of this model to mitigate solar market development volatility.

Ratepayer Cost: A dynamic demand model does not directly reduce ratepayer cost. It only helps control the impact of supply changes on SREC prices; the actual ratepayer effect of the policy will depend on market supply. If a market was likely to be under-supplied, such a policy would create lower ratepayer costs. In contrast, SREC surplus would lead to greater ratepayer costs in some years (resulting from both SREC prices which do not crash and a higher obligation), but could shorten the time duration of incentive payments if it causes the ultimate program target to be reached more quickly.

Ratepayer Cost Volatility: A market-driven demand schedule can mitigate the supply-demand imbalance in the SREC market reducing SREC price volatility. While this stabilizes SREC prices, it does so by accelerating (or slowing) SREC demand growth. This feature may lead to increases in ratepayer costs volatility despite the decreased SREC price volatility.

⁴¹ This can also lead to conditions where development occurs more quickly than anticipated by policymakers, leading to the potential for reaching overall market capacity goals ahead of schedule.

Implementation Feasibility: Since a solar carve-out program is already in place in New Jersey, adoption of a supply-responsive demand formula requires only slight modification to the current policy framework. However, legislative approval is required in order to adjust the SREC demand schedule. The state legislature would likely need to pass legislation that eliminates the existing fixed-quantity schedule and directs the BPU to establish a supply-responsive demand formula for calculating future SREC requirements. Once such legislation is passed, the BPU would need to conduct a rulemaking process in order to establish a supply-responsive demand formula and adopt the schedule change. One potential concern is the difficulty created for competitive LSEs in planning for uncertain future SREC requirements, which may impede their ability to make retail sales for periods of longer than 18-24 months without either taking on or passing through potentially material price risk. Additionally, a supply-responsive demand formula would add significant complexity to the New Jersey SREC market which may make implementation challenging. Finally, it is unclear whether a supply-responsive demand formula can be implemented without a price floor auction mechanism. Issues related to implementation feasibility for a price floor mechanism are discussed in the previous section.

Market Diversity: Unless paired with other policies that create different SREC demand requirements for different market sectors, a supply-responsive demand model will have little implication on market diversity. However, if coupled with a gating mechanism (such as that in the Massachusetts SREC-II program limiting the entry of large ground-mounted systems), market diversity could be enhanced.

Long-Term Incentive Reduction: The supply-responsive demand formula model is not designed with any declining incentive features. However, it is compatible with other long-term incentive reduction mechanisms such as a declining SACP schedule.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Supply-Responsive Demand Formula	2 to 7 **	2 to 6*	4	2	2	3

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

** High end of range represents presence of gating mechanism on overall development volume as in Mass. SREC-II

3.2.2.3 Standard Offer Contracts with Interim Quantity Limits and Volume Responsive Pricing

Several jurisdictions have implemented capped quantity policies designed to provide developers with long-term revenue certainty along with volume-responsive price adjustments. These policies are similar to traditional feed-in tariffs in that they provide long-term incentive contracts on a first-come, first-served basis, however they do not rely on administratively set pricing. These innovative policy approaches, currently being implemented in Germany and in California, can be designed to limit market volatility by

providing a limited volume of incentive over the course of a relatively short time horizon, effectively limiting market growth rates.

Example Policy: The California ReMAT program provides a standard-offer tariff for power and environmental attributes under a 10, 15 or 20 year contract. A maximum of 5MW of capacity is offered over the course of a two-month period. If the first two-month incentive period is oversubscribed at the offered price, the standard offer contract price will be lowered during the the next incentive round and developers who were not awarded contracts during the first program round will be provided with the opportunity to accept or reject the new contract price during the second round (subject to the bi-monthly 5MW cap). The figure below illustrates this mechanism.

Figure 19. ReMAT Quantity-responsive Tariff Pricing Mechanism (PG&E, 2013)



This incentive policy mechanism allows for significant control over market development volatility as no more than 5MW of capacity will be awarded tariff contracts during any given period. In the event that exogenous market factors, such as changes to global solar component prices or changes to federal incentives, affect project economics in California, the incentive mechanism can adjust upwards, increasing the contract value for incentive rounds after previous rounds are under-subscribed.

The California program is run by the state's three EDCs and they have only completed three program rounds to date. During the first program round, the standard offer contract was set at \$89.23 per MWh. Over the first three rounds, the solar tariff has declined in both the SCE and PG&E territories due to over-subscription of the initial rounds. The solar tariff price has remained stable in the SDG&E territory.

Table 6. Standard Offer Contract Rates for ReMAT Program

Utility Territory	Round 1	Round 2	Round 3
Pacific Gas & Electric	\$89.23	\$85.23	\$77.23
Southern California Edison	\$89.23	\$85.23	\$77.23
San Diego Gas & Electric	\$89.23	\$89.23	\$89.23

Policy Evaluation

Market Development Stability: As a capped-quantity policy with bi-monthly interim capacity limits, this incentive mechanism eliminates the potential for unexpected market growth. The program design provides less potential stability for rapid market slow-downs. As mentioned above, the tariff rate can increase over time in the event that any incentive round is substantially under-subscribed, however the rate of upwards price correction may be insufficient to support the market in the event of substantial and rapid changes to market prices. The price self-correction mechanism could take several bi-monthly rounds of low incentive uptake to re-establish a contract price acceptable to project developers. Real world experience with this potential issue is not available given the recent launch of the California program.

Ratepayer Cost: These policies offers solar developers long-term fixed-price contracts. Previous studies have indicated that incentive structures that provide long-term contracts can significantly lower system financing costs resulting in lowered required incentive levels and reduced ratepayer costs (Summit Blue Consulting & Rocky Mountain Institute, 2007; NYSERDA, 2012). The incentive self-adjustment mechanism also provides a competitive, market-responsive price setting mechanism that protects ratepayers from paying windfall profits to PV system owners. That said, long-term contracts can present a risk to ratepayers if installed solar prices decline significantly over the course of the contract term potentially creating a situation where ratepayers are paying a premium for solar energy compared to current market conditions. Ratepayers are however protected from upward movement in costs which might apply to the majority of SRECs traded under the current market structure.

Ratepayer Cost Volatility: As a capped quantity policy with an incentive that provides a long-term contract at a known price, this incentive mechanism limits ratepayers cost volatility within relatively limited range. Policymakers could adapt the model to establish contract pricing limits beyond which the program would no-longer make upwards tariff price revisions. Establishing such a ceiling would allow policymakers to bound the total ratepayer exposure of any similar program and further limit ratepayer cost volatility. This policy option also allows for more accurate forecasting of future incentive program costs than would be possible under an SREC program. With both volume and price relatively stable, this model is among the most stable from a ratepayer cost perspective.

Implementation Feasibility: Implementing a ReMAT-like program in New Jersey would require a substantial change to the current state solar policy framework. If the program were to be implemented as part of the current RPS solar carve out, this would require the creation of a central procurement authority that would operate the incentive program and distribute SRECs procured through the program to load serving entities. A mechanism to allocate SREC costs to LSEs would also need to be established. This policy could

alternatively be implemented by transferring the RPS obligation to the EDCs. Additionally, New Jersey previously contemplated implementing standard offer contracts, however this idea was rejected despite analysis suggesting this was a low-cost policy option. This suggests that stakeholders may have a general opposition to similar policy option (New Jersey’s Clean Energy Program, 2006).

Market Diversity: A standard offer contract with tariff adjustment mechanism program could be developed that encourages wide market diversity. Legislators or policymakers could establish multiple standard offer tranches for systems of varying size, ownership type, or site type (i.e. brownfield, rooftop, farm). The current German solar incentive program, which is similar to the California program, has eight tariff tiers in order to ensure the development of a diverse solar marketplace.

Long-term incentive reduction: While the California program does not include a mechanism to ensure long-term incentive reductions, the previously mentioned German program includes a continuous incentive degression schedule that automatically decreases the incentive payment over time. A similar mechanism could be explored in New Jersey if an explicit policy goal were to reduce or eliminate state incentives over the long term.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Standard Offer Contracts	6 to 8*	4 to 6*	9	1	6 to 9*	8

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

3.2.2.4 Competitive Procurements for Long-term Contracts

Competitive procurements for long-term incentive contracts have been implemented in a number of jurisdictions as the primary state-level solar support mechanism. Delaware, Connecticut, New York and Rhode Island currently implement competitive procurement programs for solar for either a portion of their solar market or as their sole solar incentive mechanism. This policy option differs from the previously discussed expansion of the EDC programs in that it would entail transitioning the *entire* New Jersey market to a long-term procurement program. Under a typical competitive procurement program, an awarding authority completes a series of regular, price-based⁴² procurements to award long-term incentive contracts for either electricity or electricity and environmental attributes (RECs). Solicitations are typically stratified by project sector (type or size). These capped quantity policies provide policymakers with significant control

⁴² Such programs can also incorporate non-price factors to a limited degree. For instance, Connecticut’s ZREC program reduces bid prices solely for evaluation purposes by 10 percent for a Connecticut manufactured, researched or developed generation technology (Connecticut Light & Power, 2013)

over solar market development volatility as project developers are typically unable to build projects in the state without first winning a contract through a procurement.

Typical implementation issues associated with such programs include:

- ⦿ Establishing sufficiently high barriers to entry (i.e. security, site control) provisions to avoid undue speculative bidding, while not so high as to discourage market entry and vigorous competition.
- ⦿ Allowing sufficient flexibility for developers to handle unforeseen and uncontrollable development delays, balanced with the ability to terminate and replace non-performing projects.
- ⦿ High rates of failure of contracted projects reaching commercial operation, which can result from issues such as: inflexible milestones; infrequent solicitations which encourage immature projects to bid; speculative bidding; competitive dynamics that leave insufficient profit margins for projects to address unhedged interconnection or other costs encountered after bid submission.
- ⦿ Competitive solicitations reduce developer profit and solicitations that do not effectively constrain the role of speculative bidding in setting price can cause developers to leave the market, reducing competition and undermining the ability to meet the desired targets or realize the desired savings over the long run.

These and other concerns have been addressed by a number of jurisdictions that have implemented similar programs.

Policy Evaluation

Market Development Stability: Competitive procurements create market development stability by limiting market entrance and providing incentives through regularly scheduled solicitations. This mechanism effectively eliminates the risks that the state solar market could grow faster than intended by legislators or regulatory authorities. That said, down-side market volatility, where the market installation rate is below policymaker goals, could arise if a competitive procurement program does not have mechanisms in place to ensure that project developers do not submit speculative bids that are priced too low to be completed given current market conditions or are submitted by project proponents that have not completed appropriate site due diligence.

Ratepayer Cost: Assuming that competitive procurements are well subscribed by multiple developers in the market, a competitive procurement incentive program can result in lowered ratepayer costs compared to more open market SREC incentive mechanism (NYSERDA, 2012). Two factors support this outcome. Firstly, by offering long-term contracts for PV system output with a credit worthy off-taker, developers should be able to access lower-cost financing, leading to lowered overall required incentive levels. Secondly, the competitive nature of the procurement ensures that lowest-cost installations are provided access to state incentives. A recent quantitative study completed by the authors for the state of Massachusetts comparing total incentive costs associated with multiple incentive structures identified the competitive procurement model as one of the lowest cost incentive models (Gifford et al., 2013).

Ratepayer Cost Volatility: Ratepayer cost volatility is limited under a competitive procurement incentive regime. Because total lifetime incentive costs for each PV system installed are known before the system is

constructed, ratepayer costs volatility is not a significant issue. With both volume and price relatively stable, this model is among the most stable from a ratepayer cost perspective.

Implementation Feasibility: New Jersey EDCs already have significant experience operating successful competitive procurement programs and expansion or continuation of these programs is discussed as a potential short-term policy option above. Transitioning the entire market to a competitive solicitation model, however, would require significant changes to the existing program and likely would also require new authorizing legislation. Policymakers and legislators would need to evaluate whether to operate a state-wide initiative through the EDCs with SRECs re-sold to all LSEs or whether to create a central procurement authority that would coordinate the program. Additionally, policy changes would need to evaluate the impacts of transitioning to this model on existing system owners in New Jersey. In order to address this issue, Delaware – which has made such a transition - has implemented auction tranches that distinguish between new and existing systems.

Market Diversity: Competitive solicitations can be designed to promote the development of diverse solar markets by creating separate solicitation tranches for different system sizes, ownership types and/or host types. Commenters have suggested that auction programs may not be the most equitable means of providing incentives for smaller residential and commercial PV systems as these customer classes may not have the resources and market knowledge necessary to submit well-informed bids. Given this, some states have chosen to provide solicitation-based incentives for larger PV systems and upfront payments (i.e. rebates or expected performance-based incentives) for smaller systems. This is the approach New York has taken to incentivize solar. Others (Ct., R.I.) have established different sub-procurements for different sizes of solar installations.

Long-term incentive reduction: Competitive solicitations reward least-cost developers and allow incentive rates to be set based on current market conditions promoting long-term incentive reduction. This means that if installed costs for PV systems should continue to decline in the long term, prices awarded through competitive solicitation should similarly decrease. Competitive solicitation processes also allow incentives to adjust upwards if necessitated by changes to federal incentives or global PV markets.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction
Competitive Procurement	9*	5 to 9*	9	1	2 to 9***	9

1 = Least effective at meeting objective; 10 = Most effective at meeting objective

* Range of potential outcomes based on implementation details

***Low end of range has no differentiation; high end of range has highly differentiated auctions

3.2.3 OTHER EXAMPLE POLICIES

In addition to the policy examples reviewed in detail above, stakeholders mentioned several other policies in their comments. These policy options are currently being evaluated as part of a separate BPU docket. These are described briefly below. A more extensive review of these options is available as part of docket ER13090861.

3.2.3.1 Assignment of the RPS Obligation to EDCs

The RPS currently assigns the SREC obligation to LSE. As an alternative to this model, the RPS obligation has been recommended by some stakeholders to be assigned directly to the EDCs. This could include shifting the entirety of the RPS obligation to the EDCs or just the portion of load under BGS contract. This market model is similar to the RPS model currently implemented in Delaware and Ohio, amongst others. This policy option could support either the competitive procurement or the standard offer contracts policy examples discussed above.

3.2.3.2 Creation of BGS SREC Tranches

An alternative approach suggested by some stakeholders would be to create a separate BGS SREC tranche that could result in the expansion of long-term contracts for SRECs in New Jersey. Several potential models for this approach have been discussed as part of the open BPU docket. The authors are unaware of this policy option having been implemented in other jurisdictions.

3.3 POTENTIAL NEW JERSEY POLICY OPTIONS

The following section reviews four potential policy options for New Jersey policymakers to consider. These options start with the maintaining the status quo, and progress from groupings of options evaluated that have the smallest impact on reducing future potential solar market development volatility (but the greatest compatibility with the current market structure), to those that are expected to have the greatest potential effect on solar market development volatility but pose the most significant barriers to adoption due to significant required change to the current SREC market structure. These policy options are illustrative examples of potential future legislative and regulatory efforts, and are not intended to bound potential future options. The four policy options presented are:

- Option 1: No Substantial Policy Change;
- Option 2: Implementation of Complementary Initiatives;
- Option 3: Supply Responsive Demand Formula With an SREC Price Floor; or
- Option 4: Implement a Capped-Quantity Incentive.

In addition to the options presented below, legislators may wish to consider altering the current annual SREC demand schedule to address the potential volatility drivers discussed in Section 2.3.2. For the purposes of this report, the authors assumed that the currently-legislated SREC demand schedule as established by the Solar Act was a strong indicator of legislative intent and that recommendations related to solar market development volatility should fit within the constraints of the established demand schedule.

That said, revising the current schedule would also have an effect on future potential solar market development volatility.

3.3.1 OPTION 1: NO SUBSTANTIVE POLICY CHANGES

Under this option, New Jersey policymakers would make no significant future changes to the existing solar market structure or regulations other than those currently adopted or undergoing implementation. As noted in Section 1.1, the Solar Act made a number of substantial changes to the state's solar market structure and many of these changes were made by legislators with the intent of limiting future potential solar market development volatility. For instance, the cap on future grid-supply projects, the five-year SREC banking allowance and the decreases in SACP level will help lower future potential volatility. Additionally, enhancements to the SREC program pipeline and extensions of the EDC programs should improve future SREC market supply-demand dynamics.

This policy option has a number of potential benefits which are reviewed in the following bullets:

- **Enhanced Regulatory Certainty:** This policy option conveys the greatest level of regulatory certainty and allows market participants to make investment decisions without the need to account for potential unexpected future legislative or regulatory changes that could affect market dynamics.
- **Protects Existing Investments:** The current installed solar capacity in New Jersey is the result of billions of dollars of private sector investments. Altering the state's current solar policy could substantially impact those investments (either negatively or positively) and developing new policies that equitably balance the concerns of existing system owners and other market actors may be challenging. Depending on how any market changes were perceived, this could result in investors leaving the New Jersey solar market in order to invest in states which are perceived to have more stable policy environments.
- **Acknowledges Perspective of Many Stakeholders:** Many stakeholders both in public comments and through individual discussions have supported this option, expressing an interest in limiting future structural market changes. Several developers have noted that the market has had limited time to integrate the changes made through the Solar Act, and that it is premature to conclude that solar market volatility will be a major problem in New Jersey going forward requiring further action.

There are several potential drawbacks to this policy option. These are listed below:

- **Current Demand Schedule and Federal Incentive Expiration:** The currently legislated demand schedule creates the potential for future market development volatility. As discussed in Section 2.3.2.2, the schedule requires limited capacity additions during the 2019-2022 period, reflecting a likely market contraction which a 5-year banking period could be insufficient to overcome. In addition, the 15-year SREC eligibility could create an acceleration of market capacity additions during the latter years of the existing schedule. Finally, the decrease in the Federal ITC could lead

to a rush to capture this lucrative incentive, creating over-supply in the market, followed by a market contraction. This policy option does not address these potential concerns.

- Requires Credible Commitment from Policymakers: In order to be effective, this policy option will require a credible commitment from policymakers to a 'hands-off' approach to future market adjustments. If market actors believe that legislators are willing to make significant changes in the future – such as again accelerating market demand in the event of another significant overbuild period - they may make investment decisions that undermine the existing market supply-demand schedule, exacerbating oversupply conditions and furthering the argument for policymaker intervention. Some stakeholders have expressed that this dynamic was partly responsible for the market growth that preceded the passage of the Solar Act.

3.3.2 OPTION 2: IMPLEMENTATION OF COMPLEMENTARY INITIATIVES

Policymakers could implement one or more compatible, complementary policies with the intent of reducing potential future solar market development volatility. These alternatives would build off the existing volatility-related changes from the Solar Act, and enhance the New Jersey solar market's resilience to the potential volatility drivers previously discussed in this report. Two potential complementary policies are discussed below: expansion of the EDC programs and development of a green bank. One or both of these policy options could be implemented in the coming years. Both could build off existing, established New Jersey models and regulatory infrastructure.

Expansion of the EDC programs would increase the proportion of the New Jersey market under long-term contracts. These have recently been expanded and are currently being implemented in a manner that limits their potential to create over-supply in the SREC market. Further expansion of these programs, especially if implemented along with a procurement schedule that is coordinated with the existing SREC demand schedule, would decrease the proportion of total capacity in the state needed from the 'unstructured' market. In order to reduce market development volatility, this would require consistent, regular EDC procurements along with a strategy to resell SRECs generated by these systems in a way that does not significantly upset SREC market dynamics. If developers respond by decreasing market development not under EDC program contracts, this would lower potential market development volatility. In order to maximize this effect, EDC program transparency regarding the timing of future capacity additions will be critical.

Implementation of green bank financing program would increase access to capital and lower financing PV system financing costs. As with decreases in other costs, lowering system financing costs lowers the required SREC incentive needed to construct a project. A green bank could eventually contribute to creating conditions in the future where solar project developers are indifferent to SREC revenues, effectively accelerating the transition away from this market subsidy. If a significant portion of the New Jersey solar market no longer relied on SRECs, this would eliminate many of the potential market volatility concerns discussed earlier in this report.

Expansion of the EDC programs would be expected to create the following benefits:

- ⦿ **Implemented Through Existing Models:** The EDC programs are a well-established model and have evolved over the course of the past few years based on lessons learned through the implementation process. Additionally, they have been previously approved by regulators. Given this, expansion of the EDC programs would leverage existing, proven programs that have previously received support from regulators.
- ⦿ **Market Acceptance:** A number of stakeholders expressed support for expansion of the EDC programs both in public comments and in individual interviews. The EDC programs appear to have received wide support in the developer community and have received acceptance amongst a range of solar market stakeholders.
- ⦿ **Drives Market Transformation:** The competitive process used to award long-term SREC contracts in the EDC programs drives competition within the New Jersey solar market. By awarding SREC contracts to the lowest cost developers, the EDC programs support market transformation and help to accelerate a transition away from state-sponsored incentives.

Expansion of the EDC programs is likely to create a number of challenges in the New Jersey solar market. These include:

- ⦿ **Administrative Cost:** The administration of the EDC programs creates added program costs that are ultimately paid for by New Jersey ratepayers. Expanding these programs would increase those costs, however it is unknown whether these costs increase as a proportion of the program size or whether ratepayers would benefit from economies of scale related to larger EDC programs.
- ⦿ **Increased Ratepayer Exposure:** Under the current program, ratepayers pay any difference between the cost of SRECs purchased through long-term contracts and the price received when those SRECs are re-sold into the market through quarterly auctions. Increasing the size of the current program increases potential ratepayer costs in the event that SRECs re-sold into the market are priced below the long-term contracted rate. Alternatively, the magnitude of ratepayer savings is also increased during periods when SREC prices sold in the auctions are above the contracted price.⁴³
- ⦿ **Long-term Contract Risk:** As with all incentive programs that provide long-term contracts, under the EDC programs, ratepayers risk over-paying for SRECs during the later years of the program if technological change creates conditions in which SRECs can be supplied in the future at prices significantly below the prices established under long-term contracts.

⁴³ As previously mentioned, fully evaluating the ratepayer costs of the EDC financing programs requires estimating the RPS compliance costs to ratepayers had the EDC programs not been implemented. Because the EDC program have led to market capacity additions and SREC market price reductions, evaluating only the difference between the contract price paid to system owners and the SREC resale price does not fully capture the total value of these programs to ratepayers.

- ⦿ 'Unstructured' Market Size Decrease: In order for expansion of the EDC programs to lead to lowered potential solar market development volatility, the size of the 'unstructured' market will have to decrease in order to accommodate the increased capacity procured through long-term contracts. If the unstructured market does not decrease in size in proportion to the increase in the EDC programs, this could lead to market over-supply conditions. This shift towards a larger proportion of the market under EDC contracts will likely be disruptive to the business models of some market participants.

Creation of a Green Bank financing program would be expected to create the following benefits:

- ⦿ Uses Existing Models: A New Jersey green bank could be modeled after the state's proposed Resilience Bank. This structure has already met with legislative and regulatory support and could be either expanded or replicated to provide financing for solar projects.
- ⦿ Drives Market Transformation: Financing costs can be a substantial portion of the cost of energy that drives required SREC prices and overall ratepayer costs. Reducing the costs of capital for PV systems in New Jersey could transform the state's solar market and lead to a transition away from direct state incentives.

A Green Bank financing program may present several challenges including:

- ⦿ Limited Green Bank Experience: Green banks are relatively new institutions in the United States with limited track records. Given this, it is not certain that the green bank model could leverage enough private-sector capital to have a measurable impact on the New Jersey solar market in the near term. While international models (for instance KfW in Germany) have a substantial track record of success, these have been operational for several decades and their roles in the market have evolved over time.
- ⦿ Requires Initial Capitalization: A green bank would require a significant source of funds in order to capitalize initial funding rounds. Some states have funded such initiatives with ACP funds, but New Jersey's current SREC carve-out (and RPS) supply-demand balances do not present such an opportunity. Given the tight budgets, it may be difficult to identify and implement a material source of funds to capitalize a green bank, and challenging to pass legislation which required securing initial capitalization from the general fund.
- ⦿ May Require New Legislation: Creating a green bank in New Jersey may require authorizing legislation. This may impose a significant hurdle that could make a New Jersey green bank difficult to implement in the near term.

3.3.3 OPTION 3: SUPPLY RESPONSIVE DEMAND FORMULA WITH AN SREC PRICE FLOOR

Under this policy option, the New Jersey SREC market demand schedule would be changed from a fixed annual demand established by the legislature to a supply-responsive demand requirement that adjusts based on current market conditions. This policy option would also include establishment of a soft SREC

price floor that would improve SREC price certainty and help reduce SREC market volatility. In order to maximize reduction in solar market development volatility, the policy would also likely need to include a gating mechanism for larger systems in order to limit over-acceleration of market demand and increased volatility.

This policy option would further limit future potential solar market development volatility by making the New Jersey market more responsive to outside factors and would also eliminate the issues related to market stagnation in the current SREC demand schedule by creating flexible SREC demand. The creation of a soft price floor would also help to prevent market development slow-downs during period of SREC over-supply.

The potential benefits of a Massachusetts-like supply-responsive demand formula with an SREC price floor are reviewed below:

- Reduces Potential for Future Legislative Intervention: A supply-responsive demand formula would reduce potential need for future legislative upward adjustments to the SREC demand schedule as the self-adjustment mechanism would allow demand to respond to exogenous market conditions. This would allow legislators to take a 'hands-off' approach the market without creating the risk of market collapse during periods of substantial SREC oversupply.
- Price Floor Reduces SREC Price Volatility: Implementation of a price floor would reduce potential SREC price volatility, increasing opportunities for project developers to access lower-cost bank debt and equity investment. If this floor is set appropriately, this would lower the overall system ownership costs, reducing the required SREC incentives and ratepayer costs.

Challenges related to implementing this policy option are discussed below:

- Lag-Time in Demand Adjustment: A supply-responsive demand formula may not be able to adjust to market demand quickly enough to account for rapid changes in market conditions. This lag time could decrease the effectiveness of this policy model in mitigating market development volatility.
- Ratepayer Costs: A supply-responsive demand formula would likely increase SREC demand in some years compared to the current market demand schedule, and would likely lead to hitting ultimate targets faster than current schedule which may or may not be politically acceptable. In the event that this policy options significantly increases market demand in the near term, this would likely lead to increased ratepayer costs in the near-term compared to the current policy.
- SREC Floor Pricing: Establishing an SREC floor price requires careful consideration as setting the price too high could lead to an over-incentivized market, while setting it too low may reduce market diversity. Creation of a soft price floor, similar to the floor mechanism in Massachusetts, would not require an entity take on the financial risk of supporting the price floor, however this may have limited effectiveness.
- SREC Floor Risk Transfer: Creating an SREC price floor transfers SREC market price risk from project owners to other entities. Under this scenario, policymakers may wish to reduce potential upside for developers by reducing SACP values in order to limit potential windfall profits.

- ⦿ Complexity: Implementation of a supply-responsive demand formula with an SREC price floor mechanism would add significant complexity to the New Jersey SREC market. While some project owners may be able to effectively evaluate the risks associated with such a complex policy mechanism, many potential PV system owners may not have the expertise necessary to fully evaluate the risks and benefits of such a policy structure when evaluating whether to invest in a PV system.

3.3.4 OPTION 4: IMPLEMENT CAPPED-QUANTITY INCENTIVE

The final policy option would give policymakers the greatest control over market development volatility. Under this option, the New Jersey solar market would be converted to a capped quantity incentive model under a competitive procurement structure, a standard offer contracts structure or potentially some combination of the two. Under this policy option a central authority (or authorities), or potentially the EDCs working individually or jointly, would offer regular fixed quantities of long-term SREC contracts available based on a pre-determined schedule. If the EDCs were charged with this responsibility, the RPS obligation could be transferred entirely to the EDCs. This policy option differs from the expansion of the existing EDC programs in Option 2 above in that the intent of the policy would be to bring the entirety of the SREC market into the long-term contracting structure, eliminating the potential for substantial market development volatility.

A number of critical issues would need to be addressed in transitioning the New Jersey market to this model. For instance, existing system owners have made billions of dollars in investments based on the market rules under the existing SREC market model. Any market transition would need to equitably address the concerns of these owners. This could be done in a number of ways including creating solicitation tranches that are limited to existing systems as was done in the Delaware auction model. Alternatively, the current SREC program could be closed to new systems with LSE's continuing to have an obligation to purchase SRECs from pre-transition systems at a legislatively determined schedule. This schedule would need to ramp-down over time as pre-transition PV systems lost their SREC production eligibility. This approach was taken by Massachusetts when creating the latest iteration of their SREC program.

The potential benefits of implementing a capped-quantity incentive program are discussed below:

- ⦿ Long-Term Contracts: Both an auction model and a standard offer contract model would provide system developers with long-term incentive contracts that likely would allow them to access lower-cost financing. This has the potential to lower overall required incentives, in turn reducing ratepayer costs. Additionally, an incentive program that provides long-term contracts can limit the potential for developer windfalls during later years of system operations when system investors have already met their financial return requirements.
- ⦿ Flexible to External Market Forces: A competitive auction as well as a standard offer contract incentive with automatic adjustments allows incentives to be set based on current market conditions. This allows the market to adjust to external market forces such as changes to global module prices or decreases in federal incentives.

- Market Diversity: Both an auction model and a standard offer contract model could be structured to support market diversity. In the auction model, multiple auction tranches could be structured for different system types and sizes. Similarly, multiple standard offer contract classes could be used to support a diverse market. Under these models, policymakers could define market segment growth by offering specified capacity blocks for different market segments, effectively limiting market development volatility within market segments.
- Market Transformation: Under the auction model, lowest-cost installations are awarded contracts, driving competition at the project level. Similarly, a standard-offer contracts program with automatically adjusting tariff rates creates competitive market pressures that drive down system costs. Both models can be used to support efforts to transition the market away from state-sponsored incentives.

Challenges related to implementing a capped-quantity incentive program are discussed below:

- Disruptive to Existing Business Models: Transitioning the New Jersey solar market to a capped quantity incentive structure would be a significant change in market structure and could be highly disruptive to existing developers and other market participants such as brokers and aggregators currently enabling unsophisticated owner participation in the market and providing liquidity. Given project developer's previous investment in establishing their business models in New Jersey, this change in market structure may meet with significant opposition from some existing developers.
- New Responsibility for Procurement Entity: Under either of the capped quantity models, a central authority (or authorities) would be required to take on the responsibility of awarding incentive contracts (and incur the associated administrative and transaction cost). These new responsibilities may be best coordinated through the state's EDCs given their experience running solar procurement programs.
- Speculative Bidding and Lower-than-expected Market Development: Based on industry experience with similar programs, contract failure rates for auction-based incentive programs may be high, particularly if appropriate bid requirements are not established to limit speculative bidding. Without appropriate auction entry barriers, developers may enter bids at prices that are too low to support project development in an effort to win a contract with the hope that project economics improve after the contract is awarded. This can lead to high contract failure rates and less-than-expected market capacity additions. Establishing stricter requirements to market entry can solve this issue, however, if not appropriately calibrated, these market entry barriers may prevent less-established developers from participating in the market and reduce competition. Significant speculative bidding is also a concern as it has the potential to drive legitimate developers out of the market if they perceive that they are unable to win incentive contracts if solicitations are dominated by speculative bidders. Similarly, speculative queuing under a capacity-limited standard offer system could be problematic and lead to underachievement of capacity targets.

- Auction Gaming Potential: Stakeholders have noted that competitive solicitations can present opportunities for market actors to exploit auction rules to alter clearing prices. These concerns are most relevant in solicitation processes in which only a limited number of market actors participate. Given New Jersey's robust solar market, as well as the EDC's previous experience designing and operating fair and competitive procurement processes, the authors believe that gaming is unlikely to be a major concern, unless the market is subdivided into too-small tranches.
- Project Development Uncertainty: Under both a competitive procurement model and the standard offer model proposed in this option, project developers likely will need to sell multiple projects in order to win a single incentive contract. This will increase project sales and marketing costs relative to an open-market incentive structure. Similarly, many potential project hosts will agree to work with project developers to install solar on their properties without any guarantee that the project will receive incentive funding. This can lead to frustration for potential host customers given the time commitment needed to develop a project to the point where it could participate in either a competitive solicitation or a standard-offer program (Merola, 2014).⁴⁴

As described in this section, policymakers have a range of options to choose from with respect to mitigating future potential solar market development volatility in New Jersey. These options could include a 'hands-off' policy that allows the market to fully integrate the changes created by the Solar Act to a major market re-design effort that eliminates future volatility by capping potential market activity.

SECTION 4 CONCLUSION

New Jersey has one of the leading solar markets in the United States. Over the past several years, the market has seen significant market development volatility that was the result of both external factors and high state incentive levels. The Solar Act of 2012 made a number of changes to the state's incentive program structure that likely will limit future potential solar market development volatility. Despite this, policymakers should be aware that a number of factors could drive future volatility including expected declines in federal incentives at the end of 2016 and the currently legislated SREC demand schedule in the New Jersey RPS.

Other jurisdictions have implemented a range of incentive program structures that limit market development volatility. These include policies as diverse as supply-responsive demand formulas with price floors, and market-wide, auction-based procurements. New Jersey policymakers have a number of potential policy options to choose from if concerns about future market development volatility are sufficient to spur renewed policy changes. These options could range from limited complementary policies to significant market re-designs that could help stabilize future market growth. Ultimately, policymakers must weigh the

⁴⁴ This frustration has been a significant issue in Connecticut recently, leading the Connecticut Conference of Municipalities to recommend a number of changes to state's the ZREC and LREC procurement policies.

costs and benefits of future policy changes based on their impacts on multiple stakeholders, from individual ratepayer to existing system owners and the state's EDCs. Any future comprehensive evaluation of these policy options should weigh policymaker priorities related to market development volatility against other, potentially competing, policy priorities as well as the varied interests of New Jersey's many solar stakeholders.

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SOLAR DEVELOPMENT VOLATILITY LITERATURE REVIEW

The Staff of the New Jersey Board of Public Utilities requested that the Center for Energy, Economic and Environmental Policy (CEEPP) prepare a literature review of reports and academic papers related to solar development volatility issues.¹

I. ACADEMIC ARTICLES

- a) Bird, Lori, Jenny Heeter, and Claire Krercik. "Solar Renewable Energy Certificate (SREC) Markets: Status and Trends." *National Renewable Energy Laboratory* (n.d.): Web. An overview assessment of the strategies used to develop and maintain SREC programs across the country- these markets are relatively young and compliance has proved difficult in recent years
- b) Felder, Frank, and Colin Loxley. "The Implications of a Vertical Demand Curve in Solar Renewable Portfolio Standards." *Center for Energy, Economic and Environmental Policy at Bloustein School of Planning and Public Policy, Rutgers University and Asset Management & Centralized Services Public Service Electric & Gas* (2012). Identifies the difficulties experienced in the NJ SREC market, and proposes several fixes such as a floor price, increasing the solar requirement etc.
- c) Flynn, Hilary, Dwayne Breger, and Andrew Belden. "System Dynamics Modeling of the Massachusetts SREC Market." *Sustainability 2* (2012): 2747-761. Google Scholar. Web. 7 Aug. 2013. <http://www.mdpi.com/2071-1050/2/9/2746> (Cannot save text) This article takes a look at the auction based price support mechanism, identifying that system dynamics can be helpful however there are risks to the market.
- d) Gaul, Chip, and Sanya Carley. "Solar Set Asides and Renewable Electricity Certificates: Early lessons from North Carolina's Experience with Its Renewable Portfolio Standard." *Energy Policy 48* (2012): 460-69. Google Scholar. North Carolina's experience is compared to NJ and PA to understand why the RPS has only enabled a few large solar power producers to compete with utility companies to finance, install, and operate solar generating systems.
- e) Hart, David. "Making, Breaking, and (partially) Remaking Markets: State Regulation and Photovoltaic Electricity in New Jersey." *Energy Policy 38* (2010): 6662-6673. Google Scholar. Web. NJ has experiences a boom and bust SREC market, this article looks at NJ's experience along the way.
- f) Shrimali, Gireesh, and Sumala Tirumalachetty. "Renewable Energy Certificate Markets in India—A Review." *Renewable and Sustainable Energy Reviews 26* (2013): 702-16. Google Scholar. Web. 7 Aug. 2013. Although India has great potential and aggressive renewable energy targets, the country's renewable energy market has not experienced the intended growth.

¹ This literature review was prepared by Victoria Nielsen and reviewed by Frank A. Felder.

The lack of growth can be attributed to ineffective REC market design, i.e. uncertain demand because of a lack of long term targets or price signals and unclear compliance penalties.

II. CASE STUDIES

A. New Jersey

a) State Documents

a. Legislation

1. S.B. 1925 Solar Act of 2012 enacted to Act of 2012- enacted to address low SREC prices due to an oversupplied solar market and implement policies set forth in the State Energy Master Plan.
2. S.B. 3525 Solar Advancement Act of 2010 – an attempt to provide more support for the solar market by adjusting the SACP levels, SREC requirement changed to GWh rather and a percentage, increased Solar Carve Out RPS etc.

b. Regulation and Agency Documents

3. NJ BPU Office of Clean Energy Total State Retail Sales Number Announcement Correction for Solar RPS Compliance on 10-17-13.
4. NJ BPU Office of Clean Energy EY 13 Solar Compliance Final Update as of 10-4-2013.
5. New Jersey Board of Public Utilities. Office of Clean Energy. “Request for Public Comment and Status of Proceeding to Investigate Approaches to Mitigate Solar Development Volatility.” Solar Act Proceedings Achieve. . 6-11- 2013.
6. New Jersey Office of Clean Energy – Renewable Energy Committee Meeting Market Manager Presentations on Solar Act: Mitigating Solar Volatility 11-9-12 to 10-9-2013.
 - a. Market Manager Presentation on 11-9-12
 - b. Market Manager Presentation on 12-11-12
 - c. Market Manager Presentation on 1-1-13
 - d. Market Manager Presentation on 2-14-13
 - e. Market Manager Presentation on 3-13-13
 - f. Market Manager Presentation on 4-9-13
 - g. Market Manager Presentation on 5-14-13
 - h. Market Manager Presentation on 6-11-13
 - i. Market Manager Presentation on 10-9-13
7. NJ BPU Office of Clean Energy EY 12 Solar Compliance Update as of 9-28-2012.
8. NJ Board of Public Utilities Solar Transition Working Group Straw Proposal on the Solar Transition Next Steps for EDC SREC Programs 3-6-12.
9. NJ BPU Office of Clean Energy EY 11 Solar Compliance Update as of 9-30-2011.

10. New Jersey BPU Office of Clean Energy- Renewable Portfolio Standard Rules 2010 Annual Report.
11. New Jersey BPU Office of Clean Energy- Renewable Portfolio Standard Rules 2009 Annual Report

b) Stakeholder Documents

12. Public comments on the implementation of the Solar Act received by November 7-1-13 Compiled and listed on the BPU NJ Office of Clean Energy website.
13. NJ Solar Grid Supply Association presentation on Mitigating Solar Development Volatility Analysis of the NJ Solar Project Pipeline at the Renewable Energy Committee Meeting. Trenton. 4 -9- 2013.
14. Mid-Atlantic Solar Energy Industries Association presentation on MSEIA Supply/Demand Model: Implications for Solar Development Volatility. 4-9-13 Renewable Energy Committee Meeting. Trenton. 4-9-2013.
15. Public comments on Mitigating Solar Development Volatility Act received by February 7, 2013. Compiled and listed on the BPU NJ Office of Clean Energy website.
16. Additional comments from Alpha Inception, LLC on Solar Development volatility and market structure received February 14, 2013.
17. Public comments on the implementation of the Solar Act received by November 23, 2012. Compiled and listed on the BPU NJ Office of Clean Energy website.

c.) Graphics and Data

18. New Jersey Board of Public Utilities, Office of Clean Energy Solar Project Pipeline and Installations as of 9-18-13.
19. New Jersey New Jersey Board of Public Utilities, Office of Clean Energy Solar Installations by Interconnection Type as of 8-21-13.
20. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2012 to November 2013.
21. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2011 to November 2012.
22. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2010 to November 2011.
23. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for Overlapping Reporting Years July 2011 to November 2011.
24. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for Overlapping Reporting Years July 2010- September 2010.
25. New Jersey Board of Public Utilities, Office of Clean Energy SREC Prices for July 2009 to September 2010.

B. Massachusetts

a.) State Documents

- a. Legislation
 - 26. Green Communities Act of 2008 – The initial act to establish a renewable energy and energy efficiency program in the commonwealth.
- b. Regulation and Proposed Rule Amendments.
 - 27. 225 CMR 14.00 RPS Class I Regulation 10-1-13 final rule amendments after Post 400 MW cap process.
 - 28. 225 CMR 14.00 RPS RPS Solar Carve-Out Construction Timeline Extensions Draft - guidance for Solar Carve-Out Generation Units that have not received the authorization to interconnect or permission to operate from their local distribution company by September 27, 2013.
 - 29. 225 CMR 14.00 RPS Class I Regulation 6-28-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 30. 225 CMR 14.00 RPS Class I Regulation 4-12-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 31. 225 CMR 14.00 RPS Class I Regulation 2-14-13 Tracked Changes – initial emergency rule amendments changes to address the Post 400 MW cap.
 - 32. 225 CMR RPS Original Rules Passed
- c. Agency Documents
 - 33. Reports prepared in support of the DOER’s Solar Policy Program and post 400-MW policy analysis under a competitive contract awarded to by Cadmus, Meister Consultants Group, and Sustainable Energy Advantage, LLC on September 30, 2013.
 - a) DOER Task 1: Evaluation of Current Solar Costs and Needed Incentive Levels across Sectors.
 - b) DOER Task 2: Comparative Evaluation of Carve-out Policy with Other Policy Alternatives.
 - c) DOER Task 3a: Evaluation of the 400 MW Solar Carve-out Program’s Success in Meeting Objectives.
 - d) DOER Task 3b: Analysis of Economic Costs and Benefits of Solar Program.
 - e) DOER Task 4: Comparative Regional Economic Impacts of Solar Ownership/ Financing Alternatives.
 - 34. Massachusetts Solar Market Stakeholder Meeting Presentation 8-12-2013 to review and discuss the RPS Solar Carve-Out II Updated Proposed Design. Reviews solar market data and design objectives.
 - 35. Final Determination of CY 2014 Total Compliance Obligation (per 225 CMR 14.07(2)(d)) (Revised on August 1st, 2013) Details the calculation for the obligation.
 - 36. Massachusetts Solar Market Stakeholder Meeting 6-7-2013 on the Post MW Solar Program Policy Design – Stakeholder Briefing Presentation.
 - 37. SREC Emergency Regulation Public Hearing Recordings from 7-26-13 (1-3)
 - 38. Massachusetts Solar Market Stakeholder Meeting 3-22-2013 on the Post MW Solar Program Policy Design.

39. Department of Energy Resource Email Announcements to Stakeholders on the stakeholder process for the Post 400 MW program design from May 2013-September 2013.
40. Department of Energy Resources RPS Solar Carve Out Assurance of Qualification Guideline updated on 5-22-13 to provide timeline potential generation unit with they will receive qualification under 225 CMR 14.00.
41. Solar Carve Out Credit Auction Clearing House announcement – auction at NEPOOL GIS is now open for 2011 vintage SRECs, unsold SRECs during the final 31 days of each Compliance Year’s 4th quarter trading period (May 16-June 15).
42. Massachusetts Solar Carve Out SRECS Overview and Program Basics Presentation on 12-18-2012. Describes the policy design, program growth and current market status.
43. Massachusetts RPS and APS Annual Compliance Report for 2011 4-9-2013 identifying that the Solar Carve Out obligation in 2011 fell short by 80 MW.
44. Massachusetts RPS and APS Annual Compliance Report for 2010 1-11-2012 identifying that the Solar Carve Out obligation in 2011 fell short by 34 GWh.
45. Solar Carve Out Credit Auction Clearing House announcement – auction at NEPOOL GIS is now open for 2010 vintage SRECs, unsold SRECs during the final 31 days of each Compliance Year’s 4th quarter trading period (May 16-June 15).

b.) Stakeholder Documents

46. Public Comments received on Guidelines for RPS Solar Carve-Out Construction Timeline Extensions 10-7-13.
47. Massachusetts Solar Market Stakeholder Meeting Comments on the SREC II Proposed Program Design, compiled and posted on the Department of Energy Resource website 8-12-13.
48. Massachusetts Solar Market Stakeholder Meeting Comments on Post 400 MW Post MW Program Design, compiled and posted on the Department of Energy Resource website 6-7-13.
49. Massachusetts Solar Market Stakeholder Meeting Comments on Post 400 MW design and Current Market Status, compiled and posted on the Department of Energy Resource website 3-22-13.
50. Massachusetts General Court Joint Committee on Telecommunications, Utilities and Energy Comments on Proposed Changes to the RPS Solar Carve Out Program (225 CMR 14.00) 4-25-13.

c.) Graphics and Data

51. Knollwood Energy Selling Prices for SRECs from 2010 to 2013 for each quarter sale.
52. Massachusetts Flett Exchange Graph – SREC Settlement Prices 1/7/10 to 4/26/12.
53. Massachusetts RPS Price Support Chart – Chart that explains the sets and process for the SREC auction mechanism.
54. Massachusetts Compliance - A graph that shows the RPS Class I Compliance from 2003 to 2010 (taken from the RPS Annual Report).

55. MA Department of Energy Resources Solar Carve-Out Units – A list of all the RPS Solar Carve Out qualified renewable generation units, updated on Oct. 16, 2013.
56. MA Department of Energy Resources SREC- table Minted – A table of the RPS Solar Carve Out SRECs that are minted and expected from 2010 to 2013.

C. Pennsylvania

a.) State Documents

a. Legislation

57. Massachusetts House Bill No. 100 2013 (proposed) Session- Referred to Environmental Resources and Energy Committee on 2-25-13. Increased the RPS to 15% by 2022, and the solar carve out to 1.5% by 2022. Adjusts the ACP- decreasing from \$250 in 2014 to \$50 in 2021.
58. Massachusetts Senate Bill No. 1350 (proposed) 8-14-2012 - Accelerates the existing Pennsylvania Renewable Portfolio Standard, Establishes a cap on the SREC prices through a set Alternative Compliance Payment (ACP) of \$285 per SREC out to 2019, Does not include a clause to prevent qualified out of state photovoltaic facilities from selling SRECs in the Pennsylvania market.
59. House Bill No. 1580 (proposed) Caps the Alternative Compliance. Payment (ACP) for solar at \$325, Offsetting early-year increases in the solar requirement with decreases in later years and extending the SREC program through 2026, Ensuring that utilities cannot procure any AEPS resource above the ACP price.
60. House Bill No. 1128 (proposed) September 2010- Introduced a fixed alternative compliance payment (ACP) for the Solar PV portion of the Alternative Energy Program.
61. Alternative Energy Portfolio Standards Act (S.B. 1030) (Enacted) 11-20-2004 requires that electric distribution companies and electric generation suppliers include a specific percentage of electricity from alternative resources in the generation that they sell to Pennsylvania customers.

b. Regulation and Rule Amendments

62. Final Policy Statement Order in Support of Pennsylvania Solar Projects- September 2010 The proposed policy statement sought to provide longer term revenue stability likely needed to support both small-scale and large-scale solar development, and to address other barriers.

c. Agency Documents

63. Pricing for Alternative Energy Credit Sales from 2007-2013.
64. 2011 Annual Report Alternative Energy Portfolio Standards Act of 2004 – October 2012.
65. 2010 Annual Report Alternative Energy Portfolio Standards Act of 2004 – August 2011.
66. Policy Statement in Support of Pennsylvania Solar Projects- outline a process to provide more solar alternative energy credit price certainty and to reduce or

eliminate barriers to solar project development to further the goals of the Commonwealth's Alternative Energy Portfolio Standards Act (AEPS Act). 12-3-2010.

67. Executive Summary for the Solar Working Group Documents- Summarizes the issues resolved and issues still open to discussion. 6-21-2010.
68. 2008-2009 Annual Report Alternative Energy Portfolio Standards Act of 2004 –June 2010.
69. 2007 Annual Report Alternative Energy Portfolio Standards Act of 2004 – May 2008.

b.) Stakeholder Documents

70. Pennsylvania Atlantic Solar Energy Industry Association – Pennsylvania Update Presentation (MSEIA 1st Quarterly Meeting 2013) on 1-30-2013.
71. First Energy Public Comments on the Policy Statement in Support of the Pennsylvania Solar Projects received on 3-8-2010.
72. Mid-Atlantic Solar Energy Industries Association and Pennsylvania Atlantic Solar Energy Industries Association Public Comments on Proposed Policy Statement on Pennsylvania Solar Projects received on 3-8-2010.
73. Massachusetts Office of Consumer Advocate Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-8-2010.
74. Sustainable Energy Fund Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-8-2010.
75. The Solar Alliance Public Comments on the Policy Statement in Support of Pennsylvania Solar Projects received on 3-5-2010.
76. Solar Energy Industries Association Fact Sheet for Pennsylvania 2-12-13.

c.) Graphics and Data

77. Pennsylvania Utility Commission, Alternative Energy Program Requirements for Reporting Years 2007 to 2021. (Taken from PUC website)
78. Flett Exchange graph showing Pennsylvania SREC Settlement prices from 2-28-2010 to 9-23-2013.
79. PJM-EIS Solar Weighted Average Price for SRECs from November 2009 to October 2013.