SOLAR DEVELOPMENT VOLATILITY IN NEW JERSEY

DISCUSSION DRAFT

Prepared for the Rutgers Center for Energy, Economic and Environmental Policy (CEEEP)

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ABOUT THIS REPORT

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

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About Meister Consultants Group

Meister Consultants Group (MCG) is an international, Boston-headquartered consulting firm specializing in energy policy and strategy development. MCG's clients include state energy offices, local governments, regulators, national labs, and the U.S. Department of Energy (U.S. DOE). MCG has worked with clients around the world to design and implement renewable energy policies at the local, regional and national levels. By leveraging participation and dialogue tools, MCG creates sustainability and energy strategies to manage change for businesses, governments and institutions.

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Sustainable Energy Advantage, LLC (SEA) has been a national leader on renewable energy policy analysis and program design for nearly 15 years. SEA has supported the decision-making of more than 100 clients through the analysis of renewable energy policy, projects and markets. By providing market, policy, strategic and financial analyses and support, SEA helps its clients develop the building blocks of a sustainable energy future.

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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-Assed 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 Proposals

RPS- Renewable Portfolio Standard

RSE- Renewable Serving Entities

SACP- Solar Alternative Compliance Payment

SEIA- Solar Energy Industries Association

SRECs- Solar Renewable Energy Credits

EXECUTIVE SUMMARY

Over the past several years, New Jersey has consistently had one of the largest state solar markets in the United States. Currently ranked third nationally in cumulative solar installed solar capacity, the New Jersey solar market supported an estimated 6,500 jobs in 2013. This market is 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 states 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. This increase caused the market to significantly exceed the capacity needed to meet the legislatively established RPS schedule. This led to SREC oversupply conditions that caused the value of this incentive to decline significantly resulting in a slowdown the solar market.

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

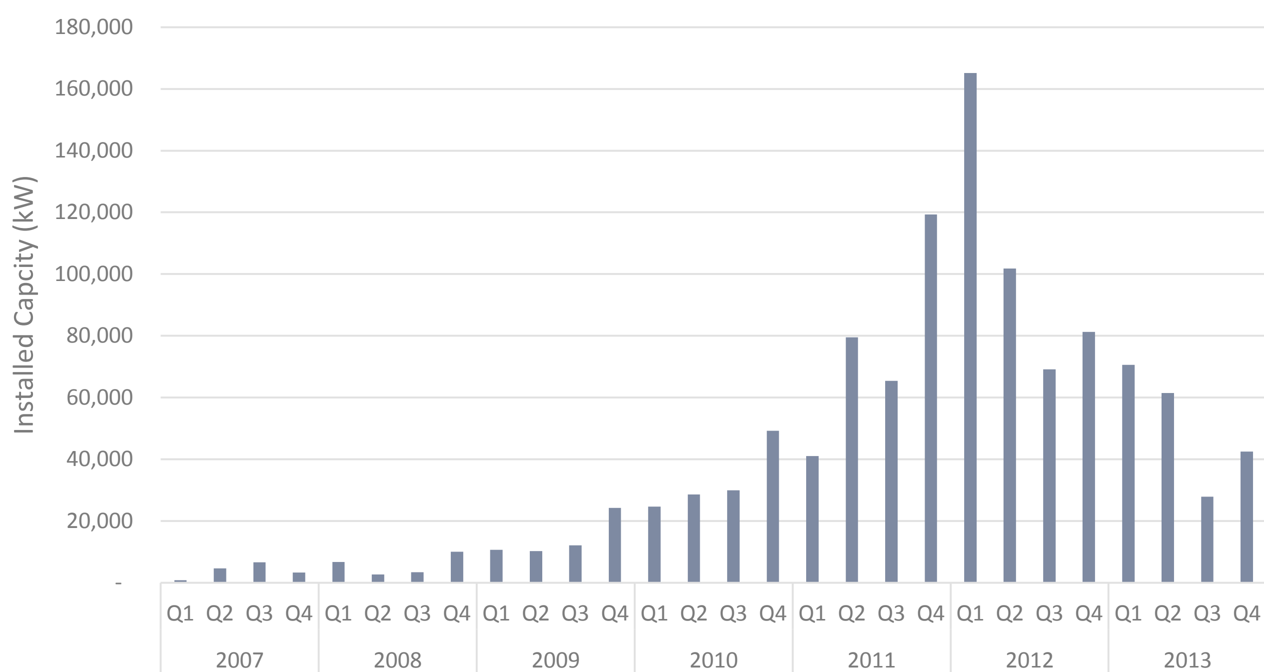
- Analyze previous performance of the New Jersey solar market with a specific focus on market development volatility,
- Identify potential future drivers and mitigants of solar development volatility in the state,
- Suggest potential policy options to encourage stable future market growth based on models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

As part of this process the Board solicited feedback from New Jersey solar stakeholders regarding how to define solar market development volatility and potential options for reducing potential future volatility. 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.

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. The figure below shows quarterly market capacity additions between 2007 and 2013 based on data compiled as part of the SREC registration program.

Figure 1 Quarterly New Jersey Solar Capacity Additions in kW (2007-2013)



As the figure 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 as well as a substantial declines in solar module costs 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 Mitigates

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 significantly reduced the likelihood of future solar market volatility, while others advocated for state agencies to make further changes to the market structure to future volatility risks.

Of the stakeholder expressing concerns about potential future volatility tended to list the following potential future 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,
- Concerns regarding regulatory stability and the enabling policy environment.

In addition to these stakeholder identified potential future volatility drivers, the authors have 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 in 2016 which has the potential to create rapid market capacity additions as developers work to meet the incentive deadline,
- 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 program supported through the state's Electric Distribution Companies that can help less potential market volatility through regular planned capacity procurements
- Future limits on large grid-supply solar projects that have the potential to quickly alter market supply and demand dynamics
- SREC supply contracting through the Basic Generation Service Auction (BGS) auction that provides some stability to SREC market prices

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

Example Incentive Models and Policy Options

Alternative solar market policy models 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 or 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
- 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
- Promoting long-term SREC tranches through the BGS auction
- Assigning the RPS Obligation to the EDCs
- Shifting to a competitive procurement incentive model (i.e. auctions)
- Shifting to a standard offer contracts incentive model
- Establishing an SREC market price floor

A detailed analysis of each of these policies is provided in Section 3 of this paper.

Finally, policy options for New Jersey related to solar market development volatility will be discussed with stakeholders at a public meeting on April 1st. Based on these discussions and further input from BPU, four policy options will be developed and further evaluated in Section 3 of this report.

Written comments regarding this report can be emailed in Word to publiccomments@njcleanenergy.com with the subject heading "Draft Solar Development Volatility Report Docket No. EO12090860V."

The comment period will end at 5:00 p.m. on April 11, 2014. All comments will be posted to the NJCEP website at the end of the comment period.

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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 market 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 solar market development volatility in New Jersey, its causes, and potential solutions to mitigate future volatility. 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 development volatility in New Jersey.

1.1 STUDY BACKGROUND

In July of 2012, the New Jersey general assembly passed S-1925 and this legislation was signed by Governor Christie (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 Board of Public Utilities (BPU) with the discretion to approve solar projects on farmland (Subsection s),
- Developing a program to support the development of PV on brownfields (Solar Act Subsection t),
- Creating a requirement that between EY 2014-2016 the BPU approve 80 MW of grid-supply capacity per year (Solar Act Subsection q),
- Defining an aggregated net metering option for public entities (New Jersey BPU, 2014).

In addition to these changes to the New Jersey 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 New Jersey Board of Public Utilities (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 to encourage 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 in New Jersey, 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 incentives;
- Ensuring regulations are consistent with legislative frameworks and intents.

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

1.2 NEW JERSEY SOLAR MARKET STRUCTURE

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 (Solar Energy Industries Association, n.d.).[1] In addition to being a leader in solar capacity additions, the New Jersey market supports a strong clean energy industry. The Solar Foundation has regularly found New Jersey to be a leading state for solar-related jobs and its 2013 census ranked the state third overall with 6,500 employees involved in the solar market. New Jersey's nationally significant solar market is supported by a number of state-level policies (The Solar Foundation, 2013). 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 entities[2] 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

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[1] The same report found New Jersey ranked first in distributed, non-utility applications.

[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.

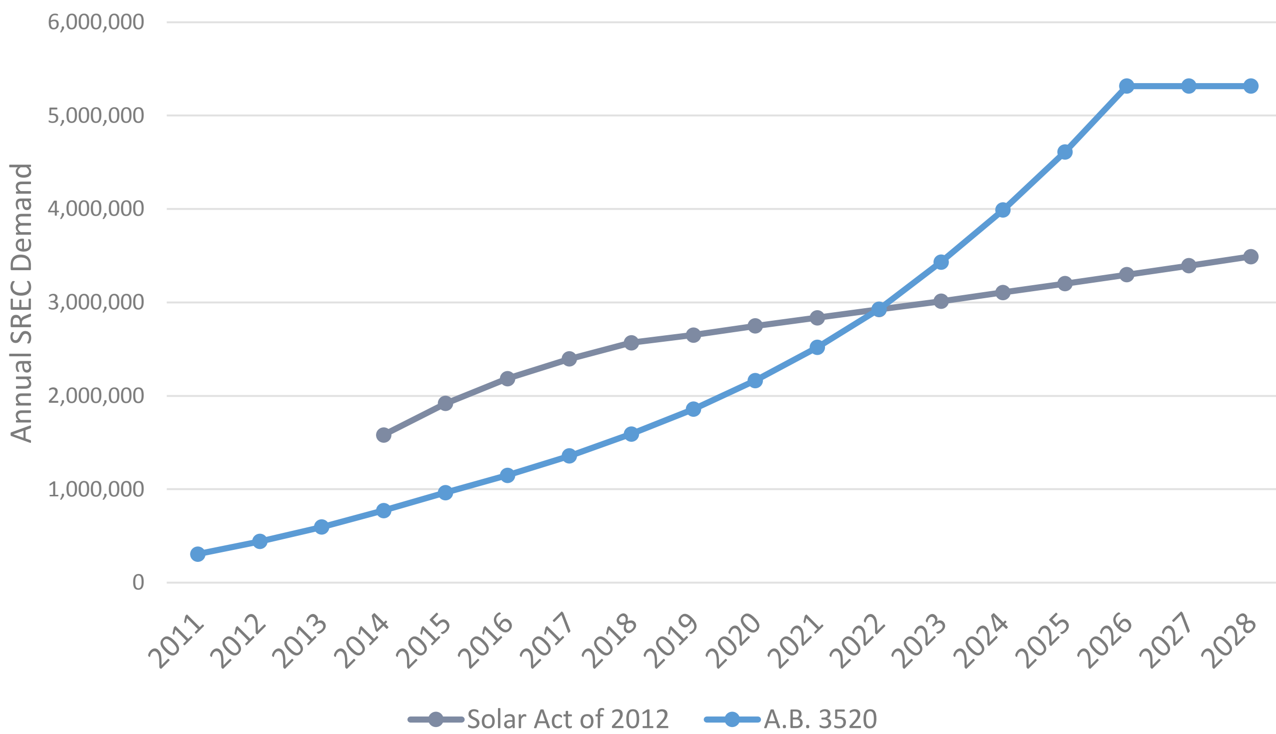
policy was implemented in 2004 in an effort to promote a market-based incentive mechanism. In 2006 the BPU worked with stakeholders to further expand the program with the goal of implementing a comprehensive incentive framework to transition the state away from solar rebates (New Jersey's Clean Energy Program, 2006). This multi-year process ended with the closing of the last rebate programs in 2010 and the last commitments made January 2011.

Demand Schedule

Rapid price decreases in the global solar module market coupled with enhancements to federal solar incentives and state SREC prices led to an unprecedented boom in solar development in New Jersey during the 2011-2012 compliance periods. This rapid market growth led to an oversupply in the state's SREC market which subsequently led to a decline in market development activity. In response to the resultant overbuild of solar capacity in relation to demand for SRECs required by the RPS, the legislature passed the Solar Act of 2012 which made a number of adjustments to market rules and the RPS compliance schedule. The legislation accelerated the RPS demand schedule in an effort to absorb surplus SREC supply, effectively doubling the 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, load serving entities (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).[3] 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.

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

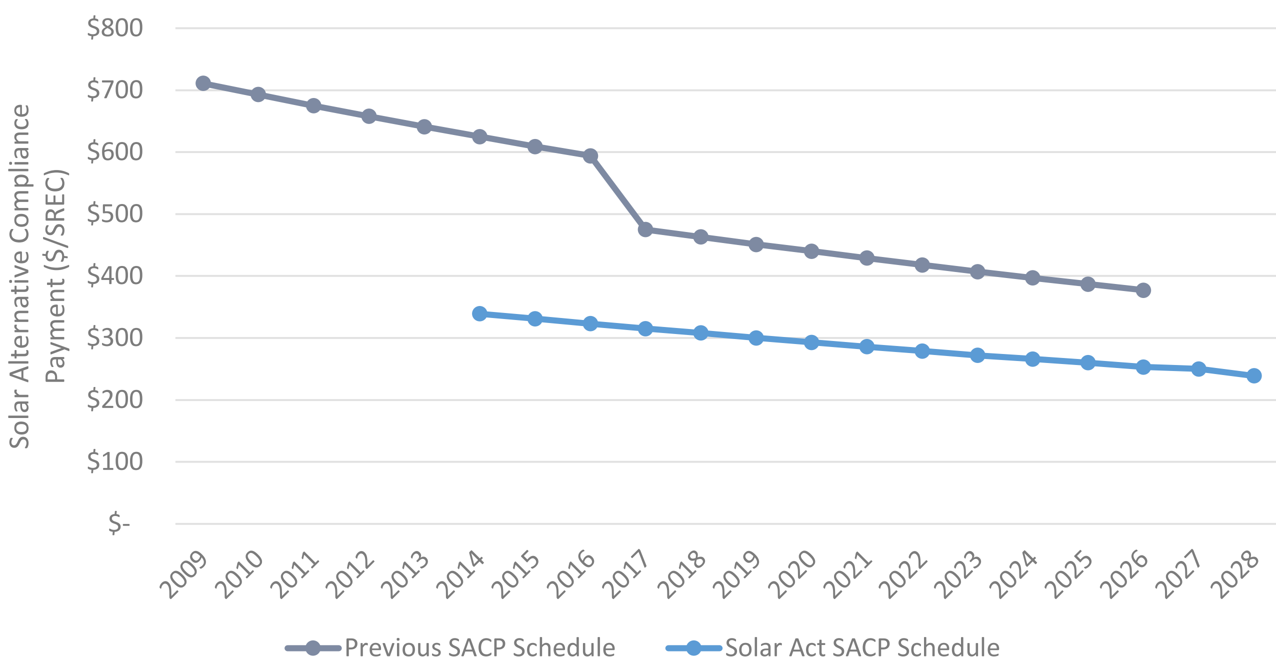
Figure 2. Projected SREC Demand under the Solar Act of 2012 and A.B. 3520



1.2.1.1 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 solar RPS compliance obligations. The SACP prices caps potential ratepayer costs and effectively 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. 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



1.2.1.2 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,[4] all market participants, from system owners to load serving entities and brokers have the ability to bank SRECs in the New Jersey market.

1.2.1.3 Electric Distribution Company (EDC) Solar Financing Programs

In addition to the basic regulatory structure of the SREC market described above, New Jersey's four electric distribution companies (EDCs) operate solar procurement and loan programs that provide long-term SREC price support for participating system owners. These programs operate within the overall SREC market structure, providing long-term incentive price certainty for a subset of PV system owners. These programs includes the PSE&G Solar Loan program[5] 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). In addition to these long-term contracting programs, PSE&G operates a direct

[4] 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 (where moving large numbers of RECs over time would distort disclosure calculations).

[5] This program is currently in its third iteration, known as Solar Loan III.

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 of solar capacity during the 2014-2016 period. Table 1 below shows the potential capacity that these programs could support over the 2014-2016 period. These programs 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 of SRECs generated from newly awarded Purchase and Sale Agreements (PSAs) in the EDC long term contracting program.

Table 1 Annual Potential MW Contribution from EDC Solar Initiatives (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

SECTION 2 SOLAR MARKET DEVELOPMENT VOLATILITY

2.1 SOLAR MARKET DEVELOPMENT VOLATILITY DEFINITION

While the Solar Act of 2012 called for the Board of Public Utilities 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, the Board staff collected stakeholder comments from January-February 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;
- Changes in installed capacity over time as well as changes in the ownership profile of installed systems over time;

Given the lack of consensus on this topic, the authors of this paper 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 market capacity additions over time. Different 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 in the market. For instance, installers may consider an average 34 percent quarter-over-quarter change in market activity as indicative of significant volatility given the business planning challenges such changes present.[6] Regulators may view the same data and note that multi-month moving averages 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.

[6] The average quarter-over-quarter change (either positive or negative) in market capacity additions in New Jersey between 2009 and 2013 was 34 percent.

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 as business and economic activity in other sectors will allow stakeholders to best evaluate market health compared to similar industries.[7]

A critical component of market development volatility includes changes within market segments in addition to overall market capacity additions. Additionally, SREC prices are a significant primary driver of market development activity. The following sections will provide a review of data related to these market development volatility 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 market composition and installation type. Data presented in this section is derived from the January 31, 2014 New Jersey Solar Installation Summary Report.[8]

2.2.1 INSTALLATIONS OVER TIME

Figure 3 below shows the quarterly capacity additions in the New Jersey market between 2007 and 2013.[9] 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 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, leading to dramatic declines in module costs. Module costs encompass between 35-40 percent of solar project costs (Solar

[7] 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.

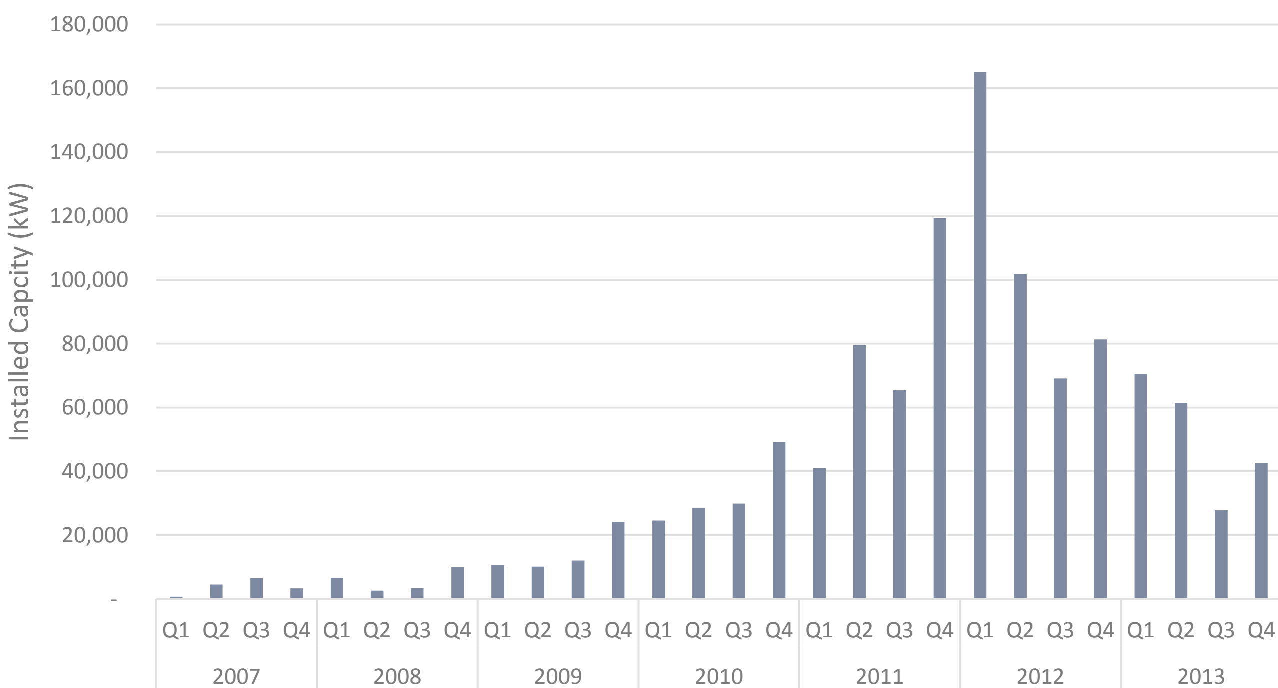
[8] As provided to the New Jersey CEP list serve.

[9] This data 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 this data.

Buzz, 2012). Between Q4 2011 and Q4 2012 average prices for blended polysilicon modules declined by 41 percent (SEIA, 2013). In 2013, the U.S. solar market experienced the first year-to-year increase in module prices since 2008, but these gains were offset by cost reductions in other hardware components (SEIA, 2014).

Following a steady decrease in quarterly installations in 2012, 2013 saw irregular 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. Importantly, quarterly capacity additions show seasonal affects that should be considered when reviewing these trends, with the third quarter of the year tending to have reduced capacity additions. 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.

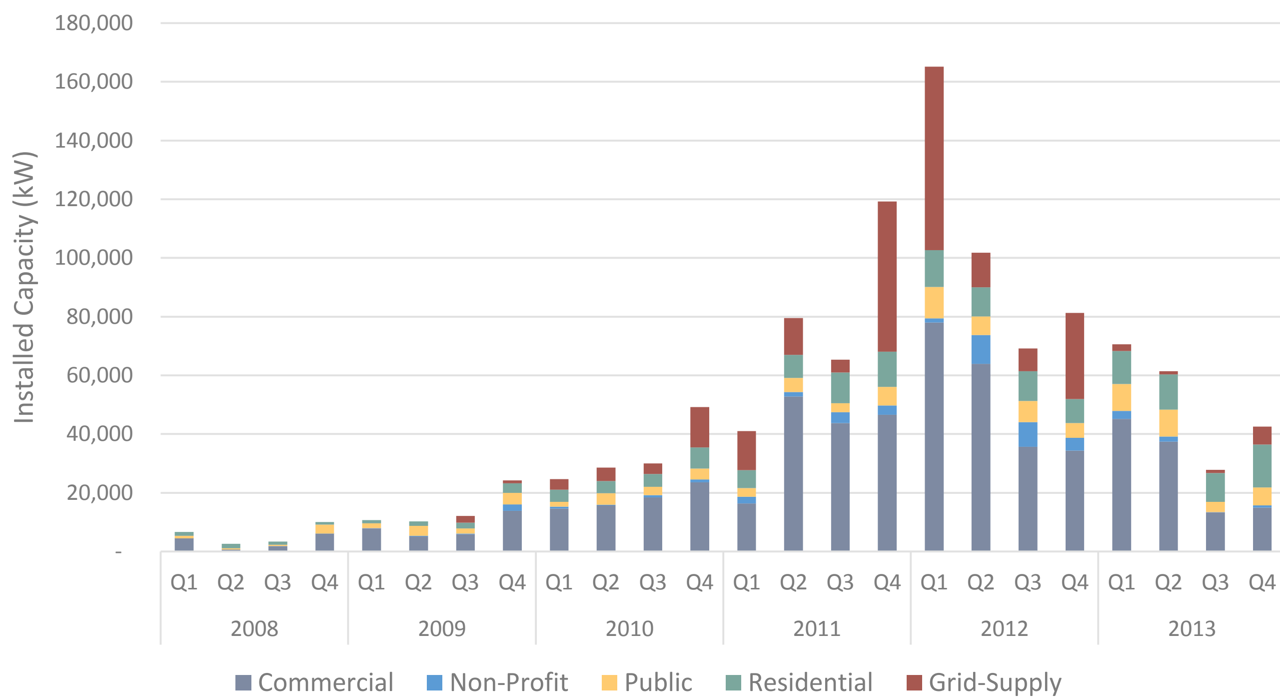
Figure 4 Quarterly New Jersey Solar Capacity Additions in kW (2007-2013)



2.2.2 MARKET DIVERSITY

New Jersey has a broad market that supports a range of project types, from large ground-mounted, grid-supply systems to small, residential systems (both third-party owned and resident-owned). Figure 5 shows the quarterly capacity additions by market segment between 2008 and 2013. Figure 6 shows the percentage of capacity additions for each installation type while Figure 7 shows quarterly capacity additions by system type relative to Q4 2013.[10] As the figures show, the composition of the New Jersey market has changed considerably over time. Grid-supply projects have provided significant capacity to the market on an irregular 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 (2008-2013)



[10] Appendix A maps the market segments used in this analysis against market the market segments provided in the NJ CEP database.

Figure 6 Percentage of Total Quarterly Capacity by Customer Type (2008-2013)

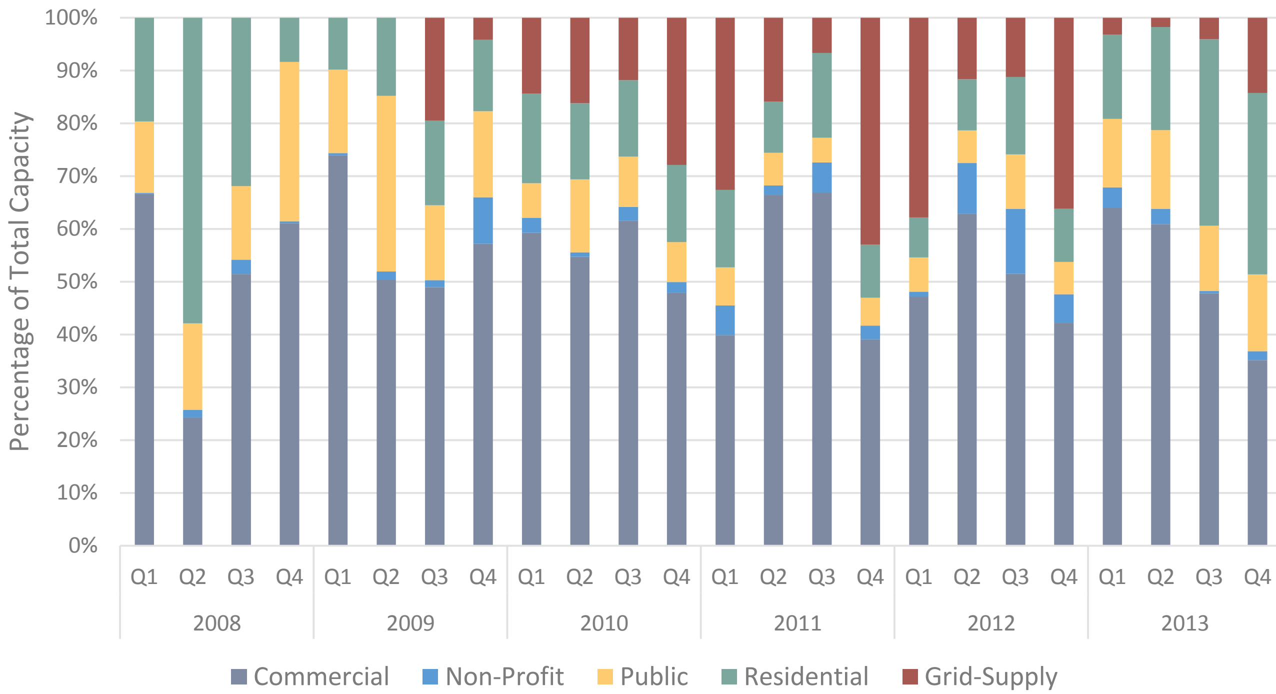


Figure 7. Quarterly Capacity Additions indexed to Q4 2013

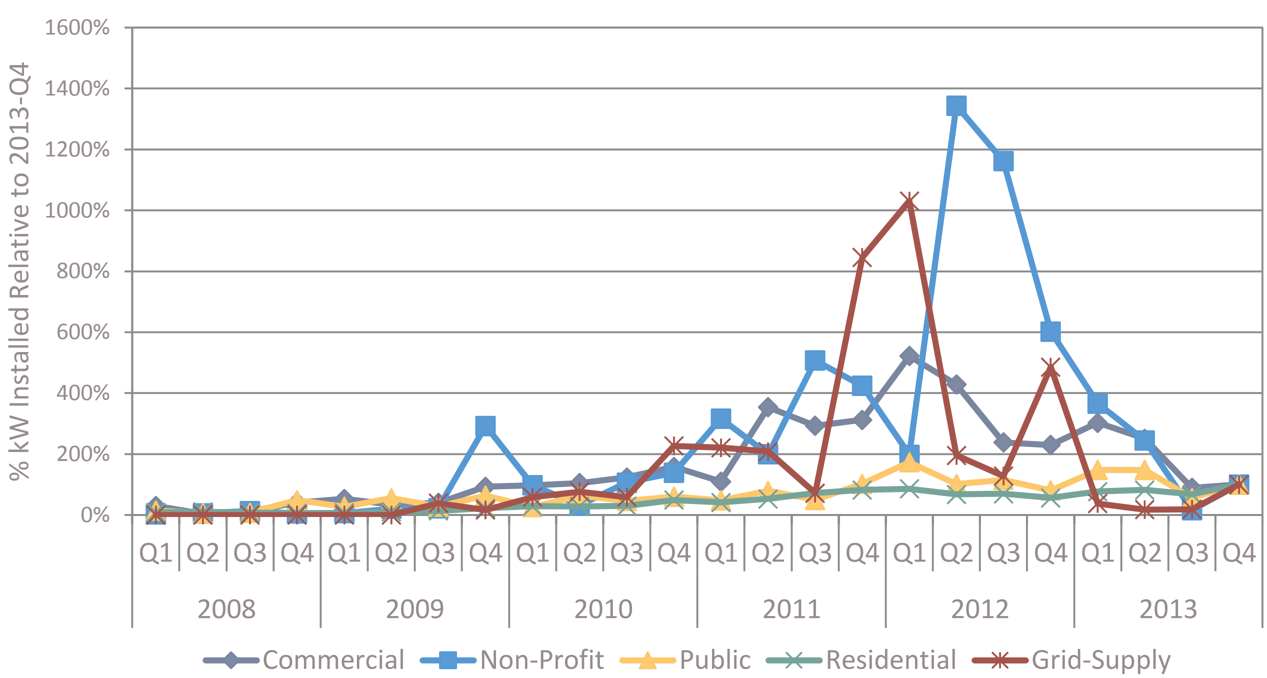


Table 2 below provides an analysis of market segment volatility. The table shows the average quarterly market additions for each market segment between 2008 and 2013. The standard deviation of these averages as well as the coefficient of variation is also shown.[11] As the table indicates, the grid-supply 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 (2008-2013)

	Commercial	Non-Profit	Public	Residential	Grid-Supply
Average Quarterly Installations (kW)	25,008	1,893	4,253	6,543	12,916
Standard Deviation	21,178	2,573	2,795	4,455	17,545
Coefficient of Variation	**0.85**	**1.36**	**0.66**	**0.68**	**1.36**

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 over the course of the 2008 to 2013 analysis period on a quarterly basis as was the relative percentage of systems installed. Figure 10 shows the number of systems installed indexed to Q4 2013. As the data shows, residential systems have made ups 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 during late 2011 and early 2012.

[11] 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 (2008-2013)

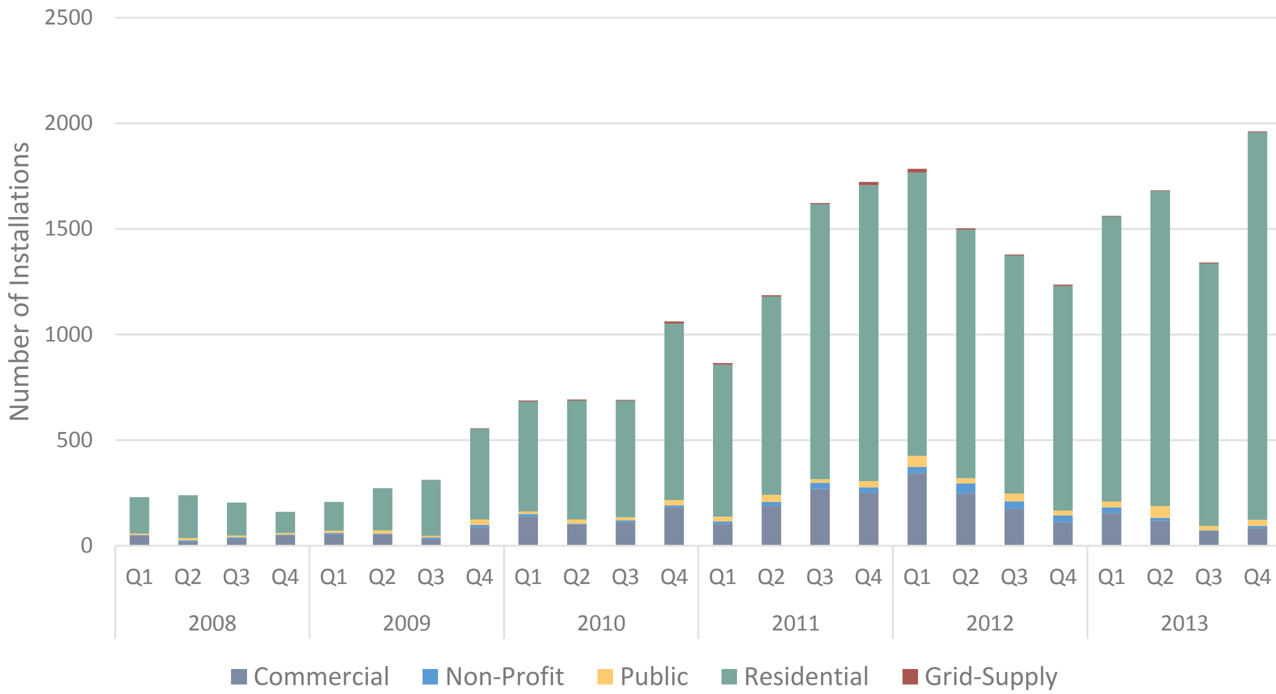


Figure 9 Percentage of Total Quarterly Installations by Customer Type

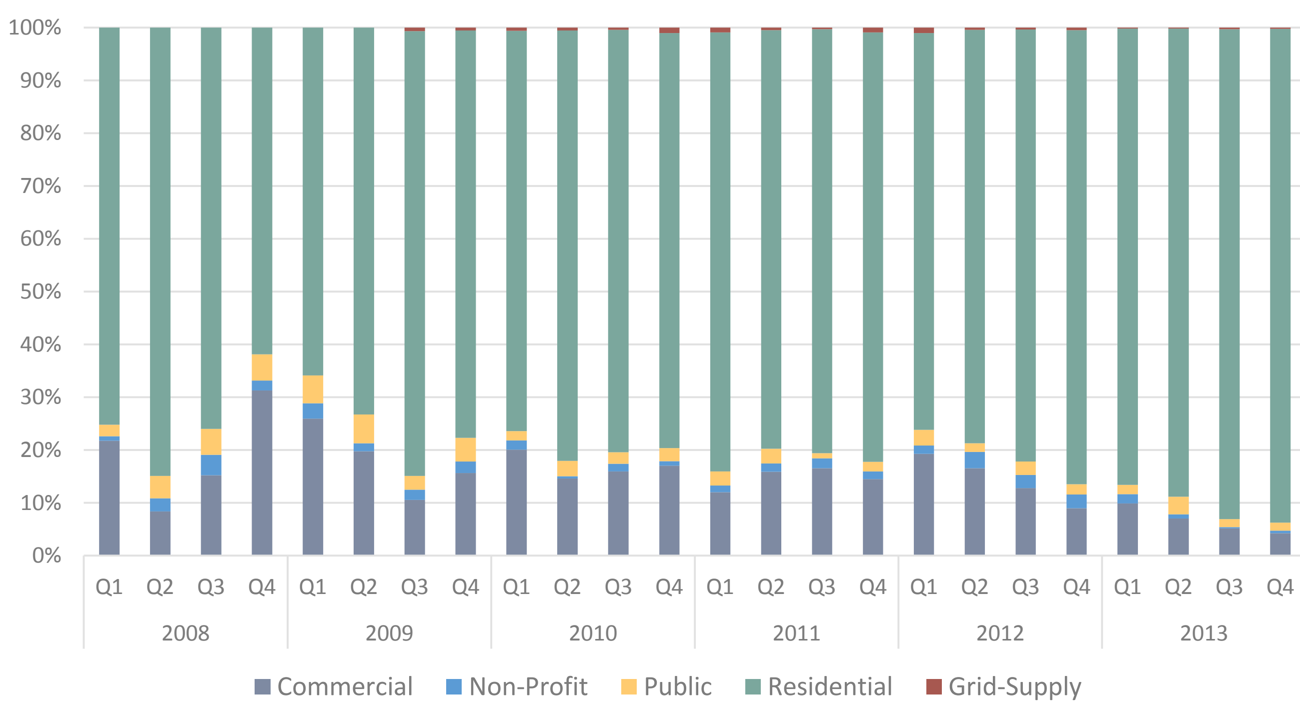
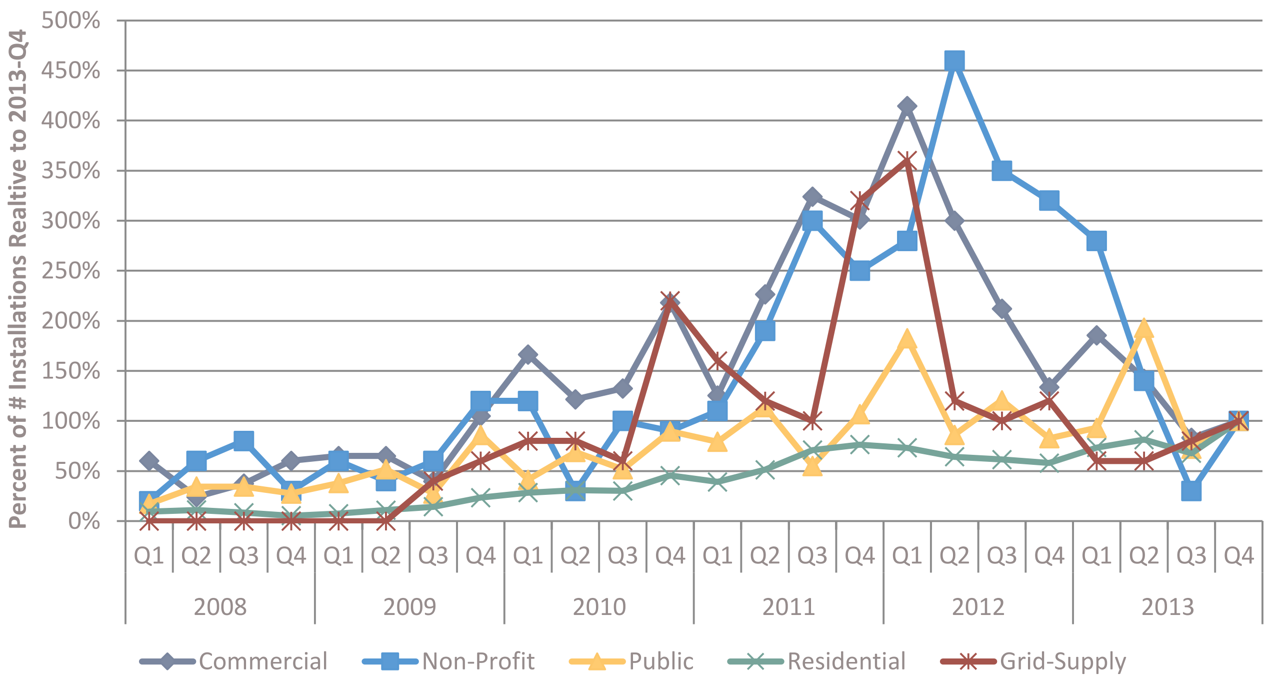


Figure 10. Number of Systems Installed Indexed to Q4 2013



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

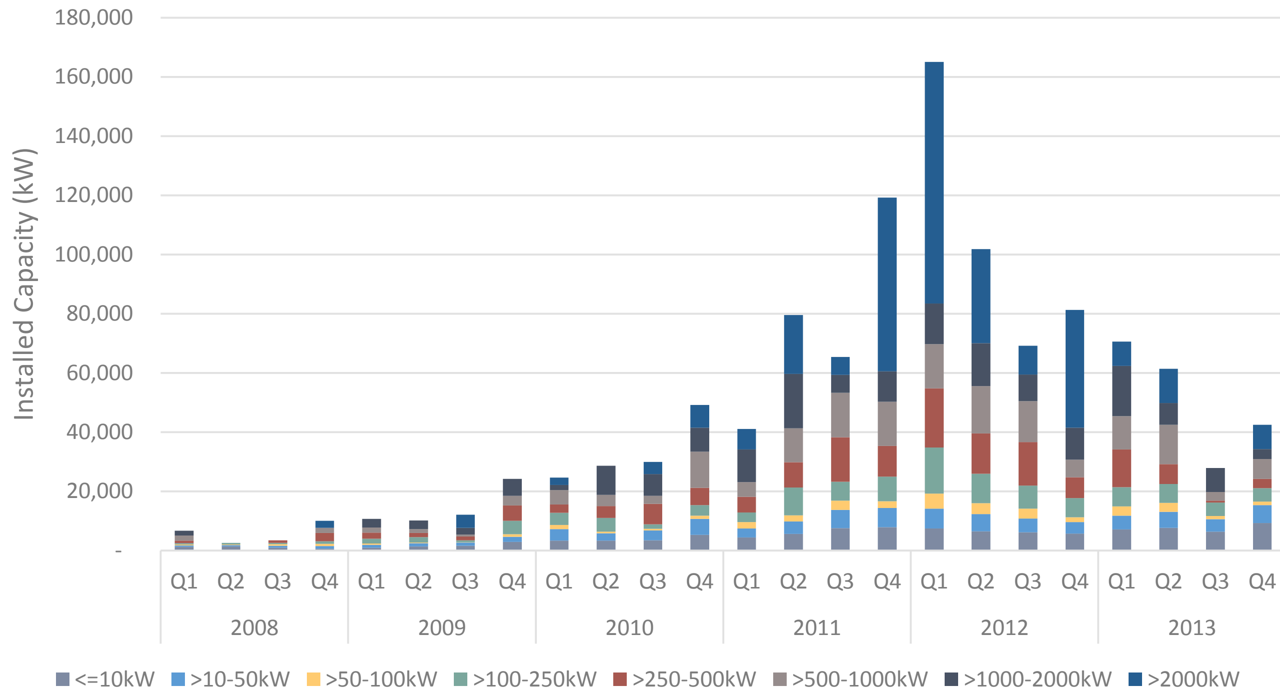


Figure 12 Percentage of Total Quarterly Capacity by System Size

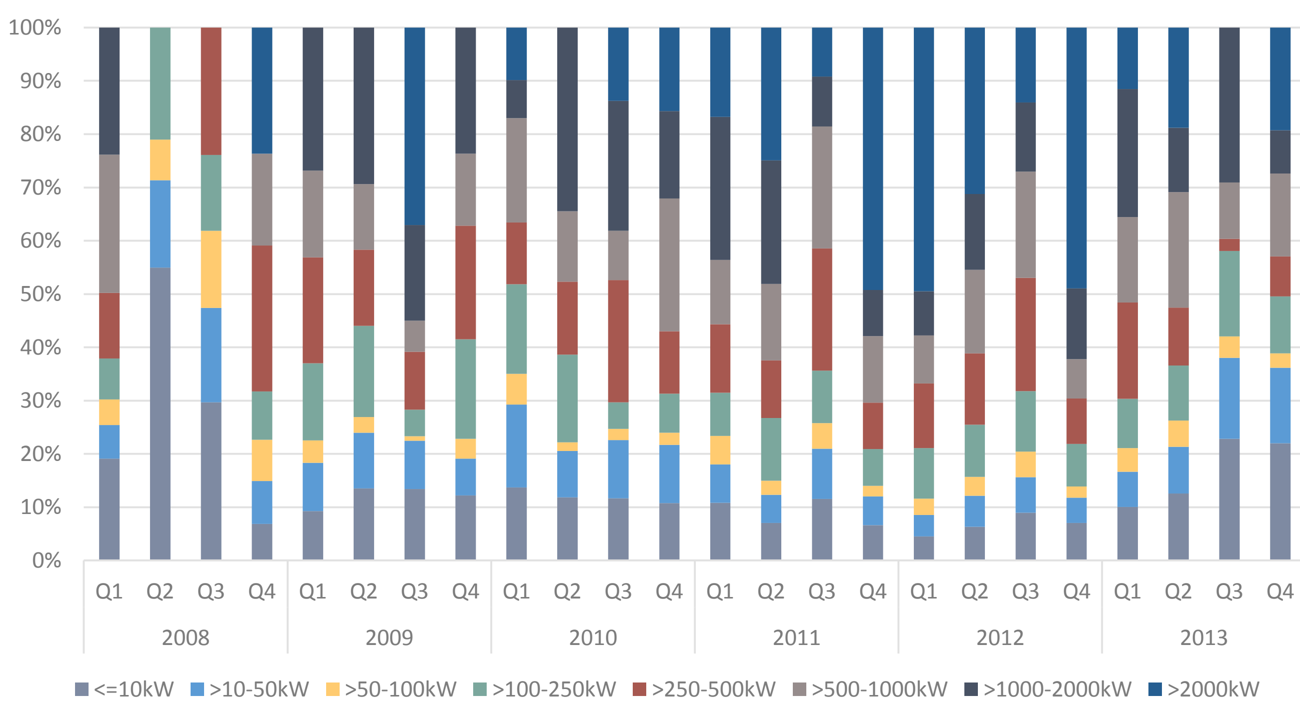
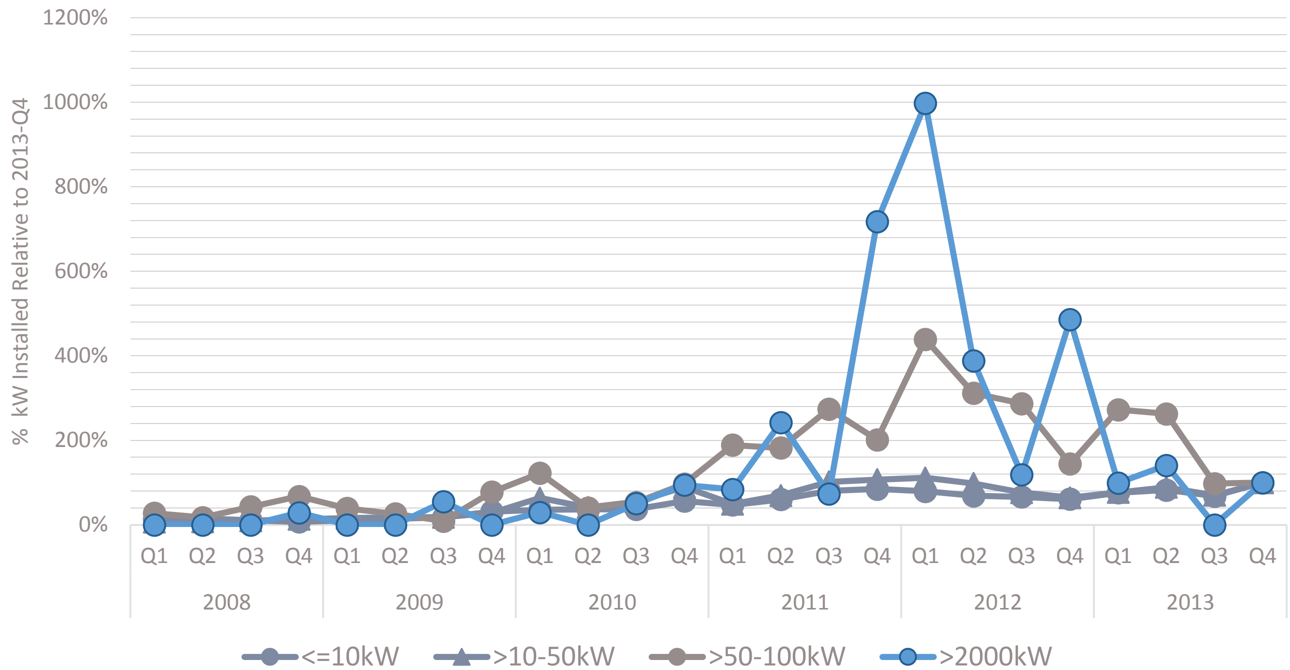


Figure 13. Total Capacity Additions by System Size Indexed to Q4 2013



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.

Table 3 System Size Quarterly Installation Volatility (2008-2013)

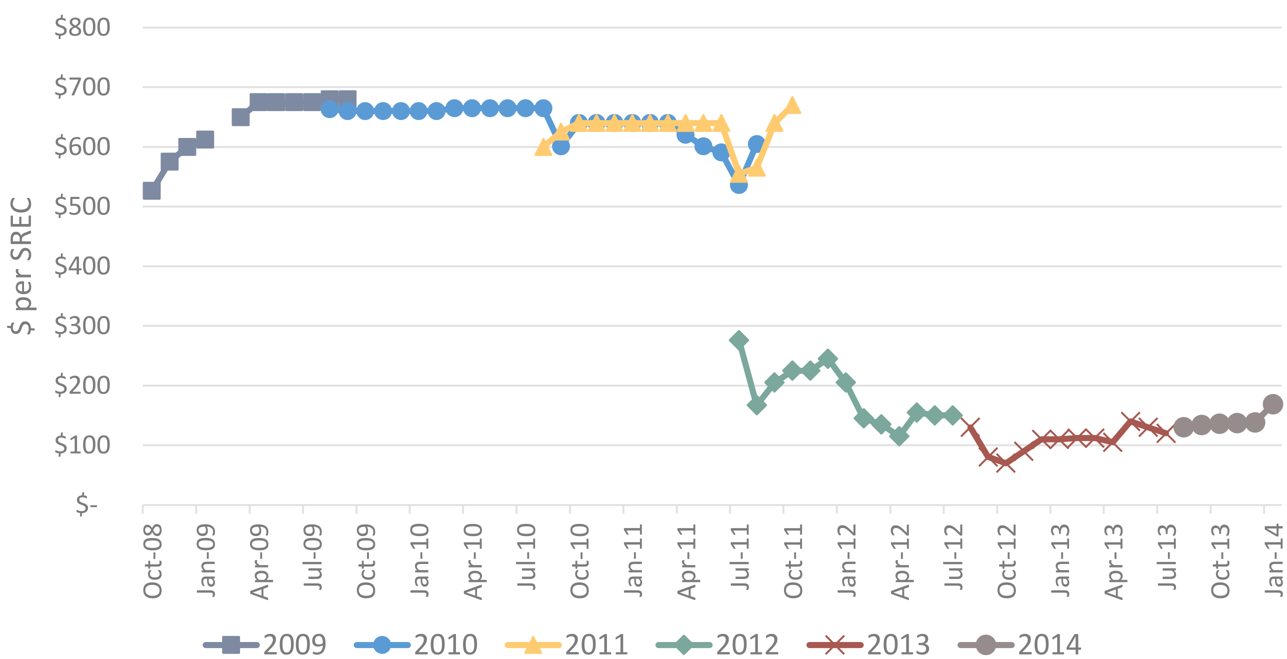
	<=10kW	>10-50kW	>50-100kW	>100-250kW	>250-500kW	>500-1,000kW	>1,000-2,000kW	>2,000kW
Average Quarterly Installations (kW)	4,531	3,466	1,624	4,753	6,592	7,508	8,189	18,968
Standard Deviation	2,690	2,149	1,335	3,731	5,432	5,520	4,919	22,968
Coefficient of Variation	**0.59**	**0.62**	**0.82**	**0.79**	**0.82**	**0.74**	**0.60**	**1.21**

As the analysis in this section has shown the composition of the New Jersey solar market has changed significantly over time. Smaller systems, and the residential sector in particular, has been the most stable market sector over time, while installation of large, grid-supply projects has been relatively volatile compared to other market segments. The timing of the market additions in the grid-supply and large ground-mount system classes suggests that these systems contributed significantly to both the overall market boom in 2011 and 2012 and the subsequent decline in market capacity additions.

2.2.3 SREC PRICES

SREC purchases are private transactions and limited information is available about the SREC transaction prices of LSEs and other market players are paying for SRECs. The BPU publishes limited information about SREC transaction prices on its website. This data present aggregated, weighted average pricing drawn from self-reported transactions as well as the individual transacted amounts, prices, and entity type per month as recorded by PJM-EIS GATS.. Given the structure of this data, it does not provide information about current market conditions. 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. 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)[12]



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

[12] Note: This graph presents a limited view of SREC prices within the New Jersey market over time as it does not take into contracted SREC transactions which are likely lower than the prices listed.

to market over-supply conditions. SREC prices have climbed since the third quarter of 2012 and are now around being traded on the SRECTrade platform for around $170 per MWh.

2.3 MARKET DEVELOPMENT VOLATILITY DRIVERS

Investor decisions to enter the solar market in New Jersey are based largely on expected solar project investment returns. If expected returns are high given current market conditions, there will be many installations and market entrants. If expected returns are low, installations are more likely to slow. These changes in expected 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
- Opportunity Costs for investments relative to alternative return opportunities
-

The following 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, the authors conducted interviews with a number of market participants and reviewed the comments provided to BPU as part of the solar market volatility proceedings. 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 VOLATILITY DRIVERS

The OCE solar market volatility public stakeholder process collected comments from a range of current solar market actors between January 7 and February 7, 2013. Additionally, several stakeholders were interviewed 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 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 remaining in the New Jersey market. Comments from these stakeholders tended to focus on four major areas of interest regarding drivers of market development volatility:

- SREC price volatility
- Long-term planning and contracting
- Market transparency
- Regulatory stability and enabling environment

A detailed discussion of each of these areas of concern 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 while others noted that fluctuations in SREC price provide critical market signals that help prevent installation rates from significantly deviating from the RPS schedule. Stakeholders indicated that if SREC prices remain within an "acceptable band", this can serve to alleviate developer uncertainty and encourage orderly market development.[13] During periods of SREC undersupply prior to the Solar Act, prices fluctuated substantially outside of this band, creating development boom-bust cycles. Parties indicated that the addition of a price floor may be able to create additional investment certainty, though it is unclear how this would affect long-run ratepayer costs or market supply and demand dynamics. 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 and another potential boom-bust cycle.

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 retail electricity market, LSE's future load can be difficult to project beyond currently contracted load, leaving limited 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 thereafter, leaving little incentive to contract forward for a longer duration. This 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.[14] Without long-term contracted

[13] 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.
[14] While this general phenomenon is likely a significant factor for many LSEs, it is notable that several major LSEs in the market have made direct solar project investments in order to meet future RPS obligations.

revenues for SRECs, project developers have to rely on more 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.[15] Not having a substantial long-term forward SREC contract market in which to hedge SREC price risk leads to increased 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 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 volatile boom-bust cycles. The creation of the EDC programs has helped provide long-term contracts into the market for some market segments, however the extent to which these programs crowd out other investments in unknown. 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

Market transparency is a key 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 instituting reporting requirements for grid-supply systems, and 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 provides far more limited insight into behind-the-meter projects. This challenge is illustrated by preliminary 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 preliminary February 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 supply/demand 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 significant improvements which can be made to the available data. The disclosed pipeline data includes early-stage projects which are likely to drop-out of the development process. One stakeholder noted that the aggregated price-data provided by the BPU – which blends term and spot prices in a non-transparent manner - does not communicate a useful price signal for developers and investors (See Section 2.2.2). There was consensus that improved price data and pipeline information could help further stabilize the market.

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

2.3.1.4 Regulatory Stability

While 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. 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.[16]

2.3.2 OTHER VOLATILITY DRIVERS IN THE NEW JERSERY MARKET

The current New Jersey solar market has a number of other features that could potentially drive future market development volatility. Some of these features relate to specific features 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 are sloped downwards, meaning that the quantity demand 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, the 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 months and sometimes years prior to the present, meaning that 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 results 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.

[16] 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 tradeable certificate markets to generate economic rents for system owners that further explores this topic in the context of the Swedish tradeable green certificate market (Bergek & Jacobsson, 2010).

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 of 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.[17] In these instances, the legislative or regulatory action effectively substitutes for a downward sloping demand curve, increasing market demand in response to lower SREC prices.

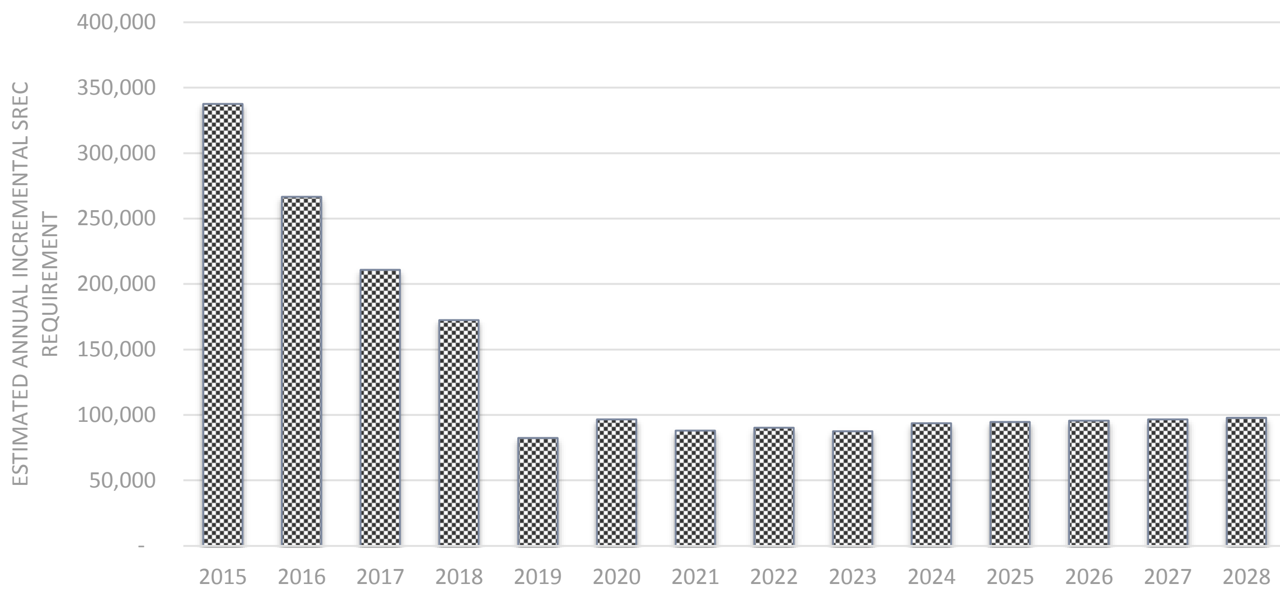
2.3.2.2 SREC Requirement Schedule

Legislatively established SREC requirement schedules can be a source of market development volatility for a number of reasons. The SREC compliance targets established under the Solar Act of 2012 includes 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).[18] Figure 15 below shows the expected number of SRECs required to be retired in each year to meet the legislative schedules between 2014 and 2028. As the figure shows, the annual incremental additional SREC demand declines each year between 2015 and 2019 suggesting a legislatively mandated contraction of annual market 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 (SRECTrade, 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.

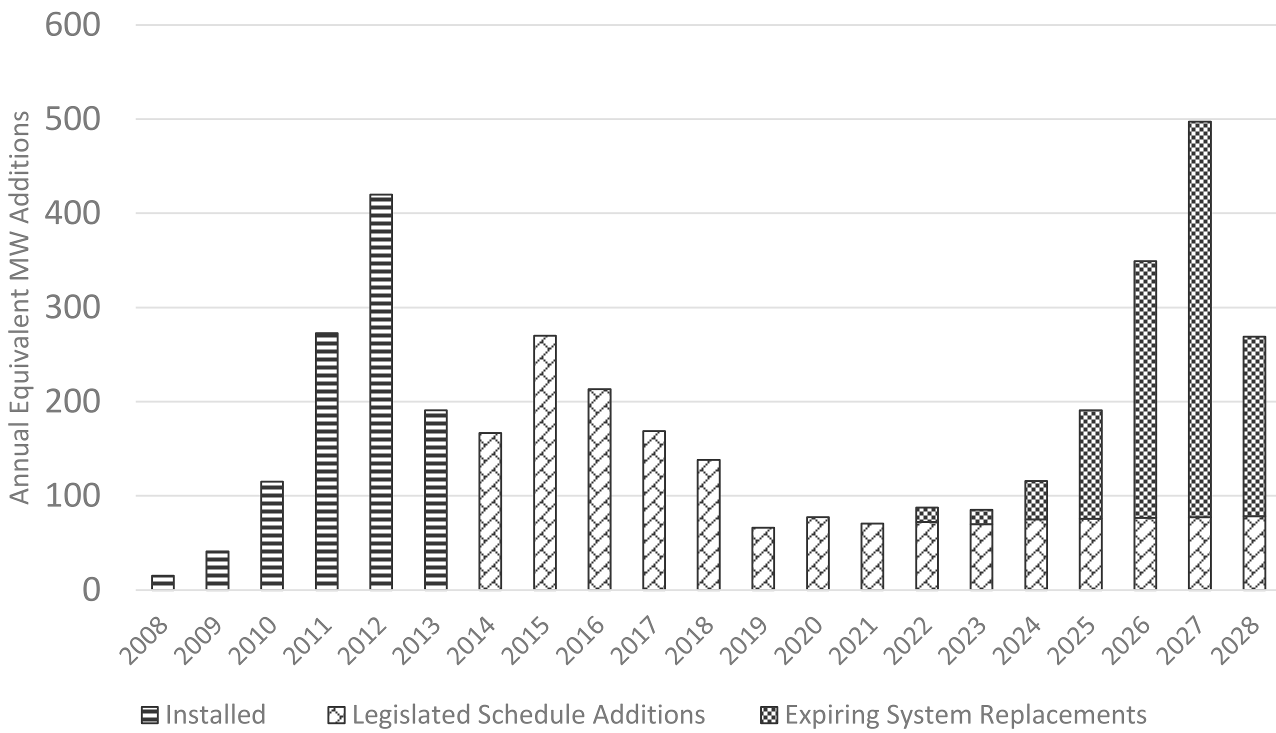
[17] Both Maryland and Massachusetts have seen recent changes to their solar program targets as a result of significant oversupply. Conversely, Pennsylvania has seen several years of low market SREC prices leading to limited market activity. This has not resulted changes to the RPS requirements.
[18] A copy of the relevant data is provided in the Appendix of this report.

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 of 2012. 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. 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. 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 be mirrored in future market development volatility.

Figure 16 Estimated Annual Equivalent Capacity Additions (MW) from Incremental Increases in SREC Demand[19]



Several important 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 increasing year-over-year capacity additions, followed by a period of no sustained annual

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[19] Note: the legislated schedule additions value for 2014 is the value of additional required capacity above the total capacity installed prior to EY 2014.

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.

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 ("Title 26- Internal Revenue Code," n.d.). 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.[20] This dynamic could have significant effects on market development volatility in the 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

[20] This dynamic contributed to the substantial New Jersey market growth in 2011 and has also been seen in PV markets in Germany 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 significant increases in market activity in advanced of the deadline (Union of Concerned Scientists, 2014).

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 NJ 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 EDC FINANCING AND DIRECT OWNERSHIP PROGRAMS

The New Jersey electric distribution companies (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. As part of 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 Energy Year 2016 should the market remain oversupplied.

2.4.2 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 capacity requirements, a limited number of large grid-supply projects can significantly and 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 of 2012 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.

2.4.3 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, 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.[21] 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 more limited importance to developers looking to build solar projects. Should installed PV costs decline sufficiently and/or electricity 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, only benefiting from federal tax benefits and the net metering value of generation (Munsell, 2013).

2.4.4 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 retail electric supplier. The BGS auction includes a requirement that tranche winners provide all-required retail services to default customers including solar RPS responsibility. 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) and 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 one-year or three-year SREC forward contracts to BGS bidders. Data from January 2014 show that 83 percent of residential customer load are taking BGS service, while 34 percent of the C&I customers are 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.

[21] Net metering does provide 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 becomes more prevalent in the United States.

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 include a defined 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, policy makers define a target quantity of PV development, but, unlike fixed 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 highly 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 which do not receive incentives are effectively unable to develop projects in the market. These policy types can significantly reduce unexpected 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. Policy makers have the ability to control market development by establishing fixed schedules for incentive availability. These program types can be designed to give policy makers 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 policy makers 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 policy makers 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 (See Appendix A). 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 contracts[22] 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 only limit potential volatility.

3.1.2 TARGET-QUANTITY POLICIES

Target quantity polices 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

[22] Auctions have also been implemented for upfront payments and other incentive types.

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 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 open the door for significantly more market development volatility than fixed quantity policies. Recognizing the challenges to creating a stable market environment that promotes sustained orderly growth, Massachusetts policy makers 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 4 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.[23] Similarly, the German feed-in tariff (FIT) for solar PV installations provided long-term contracts to system owners without an overall program cap.[24] The effect of these policies on market volatility is highly dependent on how the incentive level is determined for the policy. 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, n.d.). This standard offer tariff is designed to provide a cost-neutral tariff rate to PV system owners, 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

[23] 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 cap.
[24] 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.

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.

3.2 EXAMPLE POLICIES

This section reviews and evaluates example short- and long-term policies. These policies represent alternative or complementary methods to mitigate aspects of solar market development volatility. The listed examples were compiled from case studies, stakeholder comments, and the work of the consulting 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 market place, open to participation from an array of ratepayer classes
- Long-term reductions in incentives leading to a market transformation for solar energy
- 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. These criteria are defined as:

- Market Development Stability: This is defined a steady or stably quarterly market capacity growth rate. Target quantity policies would be expected to have less stability while more 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: Substantial variability of ratepayer costs for MWs of installed solar systems over time.
- Implementation Feasibility: This criteria evaluates how difficult implementation of the policy would be from a legislative or regulatory perspective. It also considers the relative likelihood of such changes being broadly acceptable to stakeholders.
- Market Diversity: Does the recommendation support a variety of supplier and host-project types? Does the recommendation allow both large and small firms and hosts to participate in the market?
- Long-term incentive reduction: Does the recommendation encourage the market to move-away from incentives, or complement approaches to decrease reliance of incentives.
- Consistency with Current Framework: Recommendations may be compatible or complementary to the existing RPS and SREC framework, or may operate best as a stand-alone or separate policy.

The table below summarizes how each example policy would likely align with the evaluation criteria.

Table 4 Summary Evaluation of Example Policies

Policy Model	Minimize Market Development Volatility	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Ease of Implementation Feasibility	Maximize Market Diversity	Compatibility with Long-term incentive reduction	Maximize Consistency with current Framework
Expand EDC Programs	Medium	Low	Unknown	High	Medium (Loan) Low (EDC direct purchase)	Low	Complementary
Green Bank Financing	Medium	Medium	Low	Medium	High	Medium	Complementary
Supply-Responsive Demand Formula	High	Neutral	High	Medium	Neutral	Neutral	Complementary or Stand-Alone
BGS Tranche	Unclear	Unclear	High	Low	Low	Medium	Complementary
Standard Offer Contracts with Interim Quantity Limits and Volume Responsive Pricing	High	Moderate	Low	Low	Potentially high depending on policy choices	High	Stand-Alone
Assignment of RPS Obligation to EDCs	Medium	Medium	High	Low	Depends on Design Details, Neutral to Low	Medium	Stand-Alone
Competitive Procurement	High	High	Low	Low	Potentially High	High	Stand-Alone
SREC Price Floor	Low to Moderate, depending on details	Low to Moderate, depending on details	Medium	Low	Unclear	Low	Complementary

3.2.1 SHORT-TERM POLICIES

Short-term policies are those that would 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

Policy Description: New Jersey EDCs have developed several programs to facilitate the expansion of the solar market in New Jersey in order to meet state-wide goals. The function of these programs was to improve solar market accessibility by providing long-term financing and adding security to the development pipeline to achieve RPS and policy goals. Public Service Electric and Gas Company (PSE&G) has two major programs called the Solar4All and Solar Loan programs to encourage solar development over the next three to five years. New Jersey's other electric distribution companies 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: The Solar4All program was extended in May 2013. This program allows PSE&G to directly own solar facilities on landfills and brownfields (42 MW) or at pilot sites (3 MW). During PSE&G testimony to BPU to extend the program, PSE&G articulated that adding larger grid-scale projects added security to the development pipeline (State of New Jersey Board of Public Utilities, 2013).
- Solar Loan: Customers in the PSE&G territory with behind-the-meter solar projects are eligible for the Solar Loan III program. The program provides 10-year loans on across four 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. 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. As of October 2013, the Solar Loan II program had received 1,437 applications, of which 881 had been approved or closed.
- EDC Solicitation Programs: JCP&L, RECO and AE operate solicitation-based procurement programs that provide long-term 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 would also create visibility and insurance of a solar development pipeline.

These programs can come at significant costs to ratepayers, who are passed the administrative costs of these initiatives. The effects of further expansion of EDC programs are complex, and it is unclear how expanding these programs beyond their currently authorized size would benefit or harm the solar market. These procurements could 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:

Stability: Expansion of EDC solicitation and loan programs could smooth out the development pipeline and facilitate steady increases in installed capacity. The expansion of loan programs would extend long-term financing to additional market entrants. For all rounds of the Solar Loan program, there have been applicants across all market segments. Continued regular loan solicitations could stimulate stable market development in the behind-the-meter market. For the grid-supply market, utilities could expand their current direct purchase programs. This would provide significant visibility for the development pipeline, while providing a guarantee of some level of steady development activity. The size of an EDC program expansion would need to be carefully monitored to prevent SREC oversupply.

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 Solar 4 All programs have administrative cost-passthrough mechanisms which are assessed on the bills of all PSGE&E 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.

Ratepayer Cost Volatility: It is unclear if ratepayers' 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 framework without significant intervention from the state legislature. The EDCs could petition the Board of Public Utilities for program extensions or expansions as has been completed in the past for the Solar Loan I and II programs and other EDC financing initiatives.

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, the EDC financing programs create competitive pressures in the market and assist with efforts to reduce state incentives.

Complementary vs. Stand-Alone: Expansion or extension of existing EDC programs can work in a complementary fashion with the existing SREC market model. This option could be supplemented by green bank support through credit enhancement mechanisms or additional debt-financing for grid-scale projects to open the solar market to additional commercial and residential participants.

Options	Increase Stability	Minimize Ratepayer Cost	Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term incentive reduction	Complementary vs. Stand-alone
Expand EDC Programs	Medium	Low	Unknown	High	Medium (Loan) Low (EDC direct purchase)	Low	Complementary

3.2.1.2 Green Bank Financing

Policy Description: Green banks have arisen to use public-sector capital to encourage private-sector investment in clean energy. Renewable energy projects, including solar, have historically been underserved by private-sector debt finance. As mentioned previously, solar projects have high-upfront investment costs. Currently, private-sector investors have been hesitant to offer low-interest or long-term financing options due to uncertainty about the solar market, 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 via two pathways. First, a green bank can implement specific programs using public-sector capital to encourage more private-sector investment into solar markets. The goal of a green bank should be to attract and leverage more private sector capital relative to public sector dollars invested to decrease project financing costs and lower overall incentive requirements over time. The second pathway is for the Green Bank to serve as an educational resource for other private-sector investors to better understand currently available technologies and develop appropriate, standardized underwriting practices. 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. Tools which have been utilized by green banks include competitive loans, credit enhancement mechanisms such as loan loss reserves, providing subordinated capital to occupy the first-loss position, and other low-interest financing options.

Implementation of green bank financing could help stabilize future solar market development volatility in New Jersey by providing and attracting long-term, low-cost debt to project developers. 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 lessened solar market development volatility, more rapidly than may occur in the absence of such programs. Implementing green banks require initial capitalization of significant magnitude, and staff with significant financial and technology expertise in order to be effective.

Policy Example: On the east coast, Connecticut and New York have both established green banks to support their clean energy sectors, and Massachusetts is in the process of establishing a similar program. 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 a broader array of residential and commercial credit-scores. 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 under $10 million in public funds to develop a state-wide leasing product ("CT creates $60M solar lease program," 2013).

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

In addition, the Massachusetts Department of Energy Resources announced in its final SREC-II design that it intends to establish similar programs aimed at supporting residential direct ownership. DOER plans to allocate roughly $30 million of 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:

Stability: Increasing financing options through green bank support would provide long-term, low-cost debt to solar project developers. Further programs would also aid existing market players in developing more cost-competitive projects. These improved project economics and financing conditions increase the likelihood of development in the long-run and create greater assurance of a pipeline of private-sector projects. 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, particularly for the smaller, behind-the-meter installation sectors. Reduced reliance on volatile SREC markets would be expected to smooth development volatility caused in large part by uncertain future incentives.

Ratepayer Cost: Successful state green banks are able to leverage significant private capital for limited public-sector investment. The goal is to lower the end-cost of energy generation and lessen reliance on subsidies by strengthening financing. 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 of the first capitalization funds. If utilities were involved in the initial funding of green bank programs, some costs could be passed to ratepayers.

Ratepayer Cost Volatility: Capitalizing and operating a green bank could be accomplished through a range of funding mechanisms, some of which could be directly supported by ratepayers. Even if this were the case, the impact to ratepayers would likely be minimal.

Implementation Feasibility: New Jersey has experience creating special purpose investment funds. The NJ 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 for establishing a green bank is under development. Establishing such programs may however require legislation and implementation lead-time.

Market Diversity: Expansion of financing programs could increase market diversity by increasing the affordability of solar for a wider range of entities, as well as targeting sectors that are less effective at attracting capital. In Connecticut, the Smart E-Loan program enabled financing for energy efficiency and renewable projects for 80 percent of FICO or commercial credit scores.

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 decrease as financing strength increased. Other market transformations would be necessary to completely reduce the reliance on incentives.

Complementary vs. Stand-Alone: Green banks can complement any of the short- or long- term recommendations in this document. Financing support can act as a complement or supplement to other strategies to reduce development volatility. Currently, the green bank in Connecticut operates with an auction-model as the policy framework. Hawaii's Green Energy Market Securitization program operates within a feed-in-tariff framework.

Option	Maximize Market Development Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Maximize Market Diversity	Compatibility with long-term incentive reduction	Maximize Consistency with Current Framework
Green Bank Financing	Medium	Medium	Low	Medium	High	Medium	Complementary

3.2.2LONG-TERM POLICY EXAMPLES

Long-term policies are those that would require significant policy changes. They include case studies from other jurisdictions who have taken alternative approaches to stabilizing SREC markets. These are also subjected to the same analytical framework as the short-term obligations.

3.2.2.1 Supply-Responsive Demand Formula

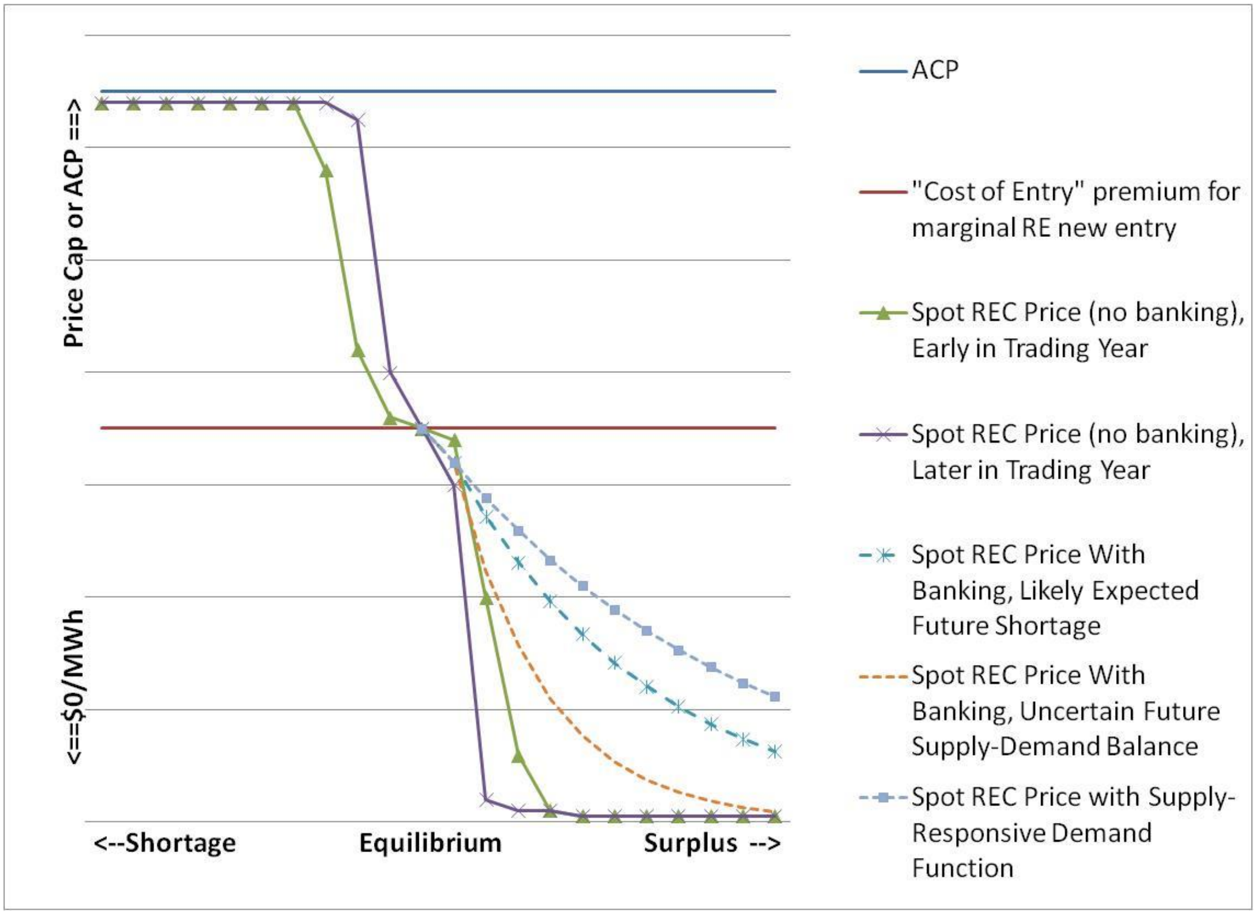
Policy Description: In New Jersey, LSE's annual SREC obligation is set at a fixed percentage predetermined by legislation. For the many reasons described in this paper, SREC market supply and demand can easily get out of balance. Under a shortage, SREC prices are high, and developers respond to those price signals, stimulating supply to catch up with demand. But experience has shown that the market can overreact to price signals and swing into substantial surplus. As recent experience has shown, SREC surpluses can take years to abate, and the presence of banking – which serves to mitigate SREC price volatility, banking can extend the time period before supply and demand re-equilibrate. In the meantime, development activity must either slow down materially, or will exacerbate the surplus.

In the absence of banking, the SREC market model could create wildly volatile prices moving sharply with relatively small changes in SREC supply because of the razor's edge nature of a vertical demand curve. SREC banking provisions, such as the ones in place prior to the Solar Act of 2012 or as extended under the Solar Act, serve to dampen the price swings, as shown in Figure 17 below.

A supply-responsive demand formula provides an alternative approach to mitigating SREC market price volatility. Instead of establishing a firm requirement schedule, jurisdictions can establish a preliminary SREC demand target which is then adjusted on an ongoing basis, using a formula that is a function of existing SREC supply and projected installation trends. The results of this mechanism are SREC obligations that respond 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 a supply-responsive demand SREC policy. Figure 17 displays an example 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 in subsequent years than under a fixed demand schedule.

Figure 17: Short-Term Relationship between Supply-Demand Balance and SREC Price under Different Policy Frameworks



Source: Sustainable Energy Advantage, LLC

The only known example of such a policy is the Massachusetts Solar Carveout, which uses slightly different approaches in the SREC-I policy tier, and the soon to commence Solar Carveout-II (SREC-II). The SREC-I policy determines the LSE's compliance obligation for a specific year based on a formula that accounts for compliance obligation, SREC generation (past and projected), ACP volume, banked volume and auction volume in the previous two compliance years. Below is the compliance obligation formula for the MA SREC-I program:

$$
\begin{aligned}
&\mathit{Total\ Compliance\ Obligation\ (Current\ Year)} \\
&\qquad = \text{Total Compliance Obligation (CY} - 1) \\
&\qquad + [(\text{Total Projected SRECs Generated CY} - 1) - (\text{SRECs Generated CY} - 2)]\text{x } 1.3] \\
&\qquad + (\text{Banked VolumeCY} - 2) + (\text{Auction VolumeCY} - 2)
\end{aligned}
$$

This mechanism allows Massachusetts to ramp-up or ramp-down the state's demand target based on recent installation trends and market conditions. Massachusetts' dynamic demand model is supported by an auction mechanism, which sets a soft price floor (constant in SREC-I and declining in SREC-II) that helps prevent SREC prices from plummeting during surplus.[25] Supply-responsive demand formulas 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 sharply ramped-up following an accelerated market growth.

To improve the responsiveness of the formula to market signals and trends, Massachusetts' proposed compliance obligation target for the SREC-II program (2016 and thereafter) which will be calculated based on both actual and projected supply, constrained by cumulative installed capacity targets.

Policy Evaluation:

Stability: Allowing SREC demand to react to supply would mitigate SREC oversupply, stabilize overall installation growth and reduce SREC price volatility. 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 is not always a perfect mechanism, although the particulars of the formula can be manipulated to seek the desired impact. The Mass. 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 minimum standard schedule. Massachusetts' new SREC-II formula has been improved to account for existing market conditions as well as projected installation trend.

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 hinges 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, 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. This mechanism would in turn stabilize ratepayer cost.

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 minimum standard schedule. The state legislature would need to pass legislation that eliminates the existing fixed-quantity schedule and directs the Board to establish a supply-responsive demand formula for calculating future minimum standard requirement. Once such legislation is passed, the Board of Public Utilities would then need to conduct an official rulemaking process in order to establish a supply-responsive demand formula and adopt the

[25] The Massachusetts Solar Credit Clearinghouse Auction is characterized as a soft floor price mechanism as in the absence of a buyer of last resort, it does not prevent market prices from transacting below the fixed price. In recent years, legislation has been proposed but not yet adopted to create mechanisms to firm up the price floor, such as requiring utilities to purchase SRECs not sold in the auction.

schedule change. One potential concern is the difficulty created for competitive LSEs in planning for future uncertain 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.

Market Diversity: Unless paired with other policies that create different minimum standard requirements for different market sectors, a dynamic demand model will have little implication on market diversity.

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. For example, to reduce reliance on SRECs as a financial incentive in the long-term, Massachusetts' SREC-II includes a declining auction floor price schedule that diminishes SREC value over time.

Complementary vs. Stand-Alone: As observed in Massachusetts, a dynamic demand model can be implemented as a complementary policy with a SREC market price floor mechanism. This policy could also potentially be implemented as a stand-alone policy.

Options	Increase Stability	Minimize Ratepayer Cost	Minimize Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction	Complementary vs. Stand-alone
Supply-Responsive Demand Formula	High	Neutral	High	Medium	Neutral	Neutral	Complementary or Stand-Alone

3.2.2.2 Basic Generation Service Auction SREC Tranches

Policy Description: Under this policy option, the Basic Generation Service (BGS) procurement would include tranches for long-term SREC contracts. This concept has been discussed in several forums as a potential strategy for providing long-term stability to a portion of the SREC market. This could be implemented through a number of potential mechanisms. Under a stakeholder proposed structure, a portion of the BGS solar obligation would be satisfied through the purchase of ten-year (or other long duration) SREC strips from non-utility Renewable Serving Entities (RSEs). As proposed by some stakeholders, the BGS suppliers would be required to purchase the SRECs procured through the SREC tranche from RSEs. RSE auctions would be conducted on a regular basis. The RSEs would take on the obligation of purchasing 10-year SREC strips in amounts sufficient to match their winning tranche bid. The market clearing price for SREC's would be set at auction for the SREC tranches. At the end of each compliance year, the RSEs would be responsible for retiring SRECs to meet their obligation. The annual SREC price for these purchases would be determined on a rolling basis. That is, the annual SREC price for the current year and all the prior year's covered under previous auctions (up to ten years prior).

There could be many variations of the above, but the goal would be:

- To separate the BGS retail load obligations of one or three years from the SREC obligations.

- To have some intermediary entity (e.g., financial institution) willing to take on the long-term risk of SRECs; and,
- To ultimately provide a market for purchasing long-term (e.g., 10-year) strips from SREC owners / solar generators.

The authors have found no other implemented examples of this proposed policy in other jurisdiction.

Policy Evaluation:

Stability While a BGS SREC tranche policy could lead to more long-term SREC price stability, its impact on market development stability is unclear. It could lead to greater instability soon after the policy was implemented as the likely demand of long-term strips by the contracting entity could provide a pathway to more financeable projects. Longer-term, the market would incorporate the schedule for BGS tranche demand.

Ratepayer Cost It is unclear how a BGS tranche might affect ratepayer costs. Transactions costs with the additional layer of procurement could drive costs up. Conversely, the demand for 10-year strips that this policy might result in, could lead to lower financing costs and might result in lower required overall SREC revenue to make projects viable. Additionally, under a BGS tranche, RSEs could take a portfolio approach to procuring SRECs allowing them to balance risks associated with future solar costs declines with the benefits of long-term contracting.

Ratepayer Cost Volatility If the BGS RPS obligation was provided by an auction tranche, and such auctions were conducted on a rolling basis, such a policy would likely decrease cost volatility; the rolling average of SREC costs over various auctions would tend to reduce cost variance.

Implementation Feasibility Implementing such a policy could be challenging as many aspects of the proposed structure have not been fully articulated by proponents, and implementing this approach would require significant vetting and potential legislative changes. Similarly, there are no known examples of the assignment via RPS auction tranche being implemented elsewhere. Finally, this approach could be politically controversial as it would require a significant change in current policy.

Market Diversity Assignment of RPS via a BGS tranche style auction would likely decrease market diversity. RSEs would have to be large, well-capitalized institutions, which would shut out many potential participants. The small group of RSE winners could create something close to a monopsony furthering dampening market diversity. Conversely, the winning RSEs would be able to satisfy their RPS obligation any way which they felt was most efficient and effective, and thus this does not preclude secondary market diversity.

Long-term Incentive Reduction Assignment of the RPS obligation via a BGS tranche style auction should be compatible with long-term incentive reductions.

Complementary vs. Stand-Alone While procurement of long-term contracts via a BGS tranche style auction is a significant methodological change, it could be complementary to the current framework.

Options	Increase Stability	Minimize Ratepayer Cost	Lower Ratepayer Cost Volatility	Ease of Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction	Complementary vs. Stand-alone
BGS Tranche	Unclear	Unclear	High	Low	Low	Medium	Complementary

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

Policy Description: Several jurisdictions have implemented fixed quantity policies designed to provide developers with long-term revenue certainty along with volume-responsive price adjustments. These unique policy types are currently being implemented in Germany and in California under the previously mentioned ReMAT incentive program. Under this policy type, a limited volume of incentive is offered over the course of a relatively short time horizon. For instance, in the California program, standard offer tariffs for power and environmental attributes are offered for a maximum of 5 MW of capacity over 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 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 18 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. The awards contracts for either excess generation or for the full output of a system. 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 5. Standard offer contract rates (power and renewable energy credits) 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:

Stability: As a fixed quantity policy with bi-monthly interim capacity limits, the California ReMAT 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 even 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 this program.

Ratepayer Cost: The ReMAT program offers solar developers long-term fixed-price contracts of 10, 15 or 20 years. 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 ReMAT incentive self-adjustment mechanism can also provide 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.

Ratepayer Cost Volatility: As a fixed 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. Policy makers 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 policy makers 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.

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. 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 policy makers 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 different 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.

Complementary vs. Stand-Alone: Implementation of a standard offer program in New Jersey would be a significant change from the current market model and would be a new, stand-alone policy that would replace, instead of complement, existing policies.

Options	Increase Stability	Minimize Ratepayer Cost	Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term incentive reduction	Complementary vs. Stand-alone
Standard Offer Contracts with Interim Quantity Limits and Volume Responsive Pricing	High	Moderate	Low	Low	Potentially high depending on policy choices	High	Stand-alone

3.2.2.4 Assignment of RPS to EDCs

Policy Description: The RPS currently assigns the SREC (and REC) obligation to the load serving entities (LSE). An LSE is either a competitive third party supplier that has an agreement to sell generation to a retail electric customer, a Basic Generation Service (BGS) provider that has won the right to supply generation to an Electric Distribution Company in the BGS auction toward meeting the demand for electricity of customers that have not switched to a third party supplier. BGS auction winners have the obligation to comply with the RPS, (i.e, retire SRECs or pay SACPs), with the compliance reporting by individual providers facilitated by the EDC. As an alternative to this model, the RPS obligation has been recommended by some to be assigned to the EDCs. Under this approach, EDCs could be encouraged to take a portfolio approach to SREC contracting, meeting their RPS obligation through a combination of spot market purchases as well as short- and long-term contracts. This strategy would also benefit from the perception that EDCs are highly creditworthy, meaning that solar developers who were awarded long-term contracts would likely find it easier to find financing.

Under the current framework, third party suppliers have no natural incentive to purchase SRECs above and beyond their obligations associated with their "booked" or contracted retail load. LSE contracts with customers do not typically exceed three years and wholesale suppliers of BGS service likewise have no incentive to contract beyond the three-year duration of their BGS tranches. Thus it is likely many TPSs and BGS providers have no natural interest in contracting SRECs for more than three years, while many solar developers desire long-term (e.g., 10 year) financeable contracts.

Examples of Assignment of RPS Obligation EDCs

While Ohio allows retail electricity choice, the state assigns its RPS obligations to EDCs per its Clean Energy Law – Senate Bill 221 –passed in 2008 which sets requirements for energy efficiency and renewable energy for each of the state's four investor-owned utilities (IOUs) (The Public Utilities Commission of Ohio, n.d.). The IOUs can meet their RPS requirements via the following methods

- Generating their own renewable energy at their own generation facilities
- Entering long-term contracts with renewable energy generators
- Purchasing (S)RECs from the market.

The Ohio IOUs have used all these methods to fulfill their requirements. While it is unclear how the Ohio approach has performed in regards to the policy evaluation criteria used here, it is clear that Ohio is meeting its RECs and SREC obligations. Importantly, the Ohio IOUs have not divested their generation assets, and unlike New Jersey, self-generation ownership is a viable option in Ohio.

Another somewhat analogous program is the New York RPS central procurement model. RPS obligations placed on competitive LSEs, and EDCs are not directly responsible for RPS compliance. Rather the regulated utilities collect a Public Service Commission-authorized charge from ratepayers and pass it on to the New York State Energy Research and Development Authority (NYSERDA), which in turn procures RPS Attributes under long-term contracts (for the Main Tier) or funds smaller generation through grant, rebate or performance-based incentive programs.

Policy Evaluation:

Stability: Assignment of the RPS to the EDCs could lead to more market development stability if a larger share of the SREC obligation was bid out or built by the EDCs on a prescribed basis. This would mean that the current EDC contracting programs might be applied to a larger proportion of the RPS requirements and that EDCs would retire SRECs instead of auctioning them into the market. This would not necessarily preclude oversupplied markets, but would probably decrease the frequency and depth of undersupplied markets.

Ratepayer Cost: If the EDCs were assigned the RPS obligation, they likely would use a portfolio approach to fulfill the obligation. The use of long-term contracts for SRECs could decrease financing costs for a larger share of the solar development in the state. However entering a larger percent of long-term contracts means locking in prices and could lead to higher ratepayer costs in the long-term if the solar costs decrease substantially. In addition, assigning the RPS obligation to the EDCs will concentrate buying power for (S)RECs of the EDCs. This could lead to less competition and a less liquid market, which could lead to higher SREC market prices.

Ratepayer Cost Volatility: If, as speculated above, the EDCs used a portfolio approach to fulfill their RPS obligations, this approach would likely decrease ratepayer cost volatility.

Implementation Feasibility: Assigning the RPS obligation to the EDCs would be a major change from current policy. The EDCs may not support having the SREC (nor REC) obligation assigned to them. While such an assignment could be accomplished (like in Ohio), it likely would require new legislation, and new procedures to implement and audit the process. Such a change would also be disruptive to the business models of many market participants as well as SREC brokers, and would likely generate opposition by those parties.

Market Diversity: It is possible that this policy would be neutral to market diversity. Today, projects in general compete on price in a single market, and the EDCs could procure on price alone as well, not fundamentally altering the relative economics of solar projects. How market diversity might be affected would ultimately depend on the design details of how EDCs handled their new RPS obligation. There is a significant possibility it could decrease market diversity, or a stratified approach could be developed to maintain or even increase market diversity (for example, by offering different levels of incentives to different segments).[26]

Long-term Incentive Reduction: The assignment of the RPS to the EDCs would be compatible with the long-term incentive reductions, particularly given the likelihood that the EDCs would procure SRECs through a competitive bidding process.

Complementary vs. Stand-Alone: Assignment to the EDCs of the RPS obligation would be a stand-alone policy and have the potential to crowd-out other policy goals as the EDCs likely would try to attain their SREC targets through the cost efficient means possible.

[26] While not directly analogous, a similar example is the Massachusetts SREC-II policy, which will support market diversity by applying different 'SREC Factors' – or SRECs granted per MWh – to different segments which require different levels of incentives due to different cost structures.

Options	Increase Stability	Minimize Ratepayer Cost	Lower Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction	Complementary vs. Stand-alone
Assignment of RPS Obligation to EDCs	Medium	Medium	High	Low	Depends on Design Details, Neutral to Low	Medium	Stand-Alone

3.2.2.5 Competitive Procurements for Long-term Contracts

Policy Description: 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. Similarly, the current EDC long-term financing programs are a form of competitive procurement.

Under a typical competitive procurement program, an awarding authority completes a series of regular, price-based[27] procurements to award long-term incentive contracts for either power or power and environmental attributes. Solicitations are typically stratified by project sector (type or size). These capped quantity policies provide policymakers with significant control 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 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, to name a few.

[27] Such programs can also incorporate non-price factors to a limited degree. For instance, Connecticut's ZREC program reduces bid prices for evaluation purposes only by 10% for a Connecticut Manufactured, Researched or Developed generation technology (Connecticut Light & Power, n.d.)

- 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 realize the desired savings over the long run.

Policy Evaluation:

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 policy maker goals, could arise if a competitive procurement program does 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 results 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 costs 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.

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 new authorizing legislation. Policy makers 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 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 installation 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.

Complementary vs. Stand-Alone:

Options	Increase Stability	Minimize Ratepayer Cost	Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term incentive reduction	Complementary vs. Stand-alone
Competitive Procurement	High	High	Low	Low	Potentially High	High	Stand alone

3.2.2.6 Establish SREC Price Floor

Policy Description: Establishing a 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, this 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 elsewhere in this section.

A variation of this model was discussed during the 2007 market transition proceedings. Under the proposed 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, a stakeholder suggested an alternative proposal to establish a soft price floor through the existing EDC SREC auction process. Under this model, if the price in the quarterly auction for SRECs procured under the EDC financing does not clear the pre-established floor, 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.[28] Any floor policy would have to be implemented with caution; a stated policy goal of the Board of Public Utilities is long-term incentive reduction. Should the New Jersey solar market progress such that the equilibrium price 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 stable floor price mechanism. A 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 restraints. ACPs are also a potential funding source, but provide fluctuating revenues since payments are tied to market activity.[29] There is no guarantee that ACP funds would exceed floor payments over the full compliance period.

Example Policy: In Massachusetts, the SREC-I and SREC-II programs are supported by the Solar Credit Auction Clearinghouse, creating a soft 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. SRECs offered in the auction are sold at a pre-determined price of $300/MWh.[30] The program design includes a series of iterative rounds intended to incentivize LSEs or others to purchase from auction. During successive rounds, if the auction has not cleared, the shelf life of all SRECs is extended and future SREC obligations on LSEs are increased. The design of this mechanism is highly integrated with the supply-responsive demand schedule described in Section 4.1.2.1. 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 sold offered in the auction (MassDOER, n.d.).[31] 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. 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 process sunk below the floor, they did not collapse, staying above about $185/MWh at the bottom of the market and usually maintaining at a price in the low $200s/MWh during periods of surplus reflecting a time value of money discount to $285/MWh. 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.

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[28] A full evaluation of this effect is beyond the scope of this report, however efforts to boost 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.

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

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

[31] In response to this, the Department of Energy Resources (DOER) used alternative compliance payment funds to purchase SRECs from system owners.

The Connecticut Class III REC market has both an ACP and a fixed price floor. The market is designed to support energy efficiency projects and combined heat and power development. 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, but there is no buyer of last resort to support the price; therefore, many RECs remain unsold, and 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,[32] pushing the market back into shortage, temporarily. We expect that as additional supply responds to higher price signals, that within a few years the market will return to its condition 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 fiat model currently active in Connecticut.

Stability: A price floor mechanism coupled with a buyer of last result would dampen SREC price volatility in the market and help support market development activity during periods of SREC over-supply. 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.

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. However, it could lead to over-stimulation of the market and without an increase in demand, could exacerbate over-build. A floor coupled with a mechanism to increase ultimate demand to absorb surpluses may be more effective at stabilizing development rates.

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 than a soft floor at reducing the cost of capital (MassDOER, 2013). This affect could lead to lower overall

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

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 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 at the expense of ratepayers. In order to adapt to changing market conditions, the floor price would also need to adjust over time creating implementation challenges related to SREC vintage tracking.

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 cost variability passed to ratepayers.

Implementation Feasibility: The creation of a hard 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.

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 add substantial complexity.

Long-term Incentive Reduction: By having both a SACP and a floor, SREC market prices will 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.

Complementary vs. Stand-Alone: Creating a price floor could work within the current policy framework. A floor mechanism could be created to supplement and work alongside the existing RPS and SREC framework, akin to the current process in Massachusetts.

Options	Increase Stability	Minimize Ratepayer Cost	Ratepayer Cost Volatility	Implementation Feasibility	Increase Market Diversity	Long-term Incentive Reduction	Complementary vs. Stand-alone
SREC Price Floor	Low to Moderate, depending on details	Low to Moderate, depending on details	Medium	Low	Unclear	Low	Complementary

3.3 NEW JERSERY POLICY OPTIONS

Policy options for New Jersey related to solar market development volatility will be discussed with stakeholders at the April 1st public meeting. Based on these discussions and further input from BPU, four policy options will be developed and further evaluated in this section.

Written comments regarding this report can be emailed in Word to publiccomments@njcleanenergy.com with the subject heading “Draft Solar Development Volatility Report Docket No. EO12090860V.”

The comment period will end at 5:00 p.m. on April 11, 2014. All comments will be posted to the NJCEP website at the end of the comment period.

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