AN ANALYSIS OF POTENTIAL RATEPAYER IMPACT OF ALTERNATIVES FOR TRANSITIONING THE NEW JERSEY SOLAR MARKET FROM REBATES TO MARKET-BASED INCENTIVES

Prepared for:
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1. INTRODUCTION

This report summarizes the results of a ratepayer impacts analysis of seven proposed options for transitioning the photovoltaic (PV) portion of the Board of Public Utilities' Office of Clean Energy's (OCE) Customer On-site Renewable Energy (CORE) program from providing up-front rebates to a system that fosters market-based support for renewable energy project development. This detailed ratepayer economic analysis was recommended in Summit Blue's March 15, 2007 report on the proposed transition scenarios, "Preliminary Review of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives" (March 15th report). The March 15th report evaluated each of the proposals based upon a set of criteria developed and based on OCE-defined principles; however, this current analysis focuses on only one aspect of the criteria: the ratepayer impacts (RPI) of each scenario. Both this report and the previous report are part of a larger renewable energy market assessment that the Summit Blue team is currently conducting for the New Jersey Board of Public Utilities (BPU).

The primary goals of this analysis are to:

1. Perform an independent, unbiased analysis of potential ratepayer impacts (RPI) of the proposed PV market transition scenarios.
2. Conduct a Monte Carlo analysis to determine the potential range of RPI.

The RPI results of this analysis combined with the qualitative analysis of the scenarios in the March 15th report will be considered as part of the BPU's on-going SACP (Solar Alternative Compliance Payments) proceeding.

This analysis focused on a detailed scenario-based analysis of potential RPI based on the various proposed scenarios and their associated impacts on: 1) ratepayer costs; and 2) their ability to stimulate the level of development necessary to meet RPS requirements.

This analysis was conducted in two phases. During **Phase I** the models used for the preliminary ratepayer analysis conducted under the March 15th report were reviewed and a more sophisticated analytic model was developed. This new model started with the project financing objectives and determined the level of incentives required for financial viability of projects. These incentive levels were then run through a ratepayer impact (RPI) analysis. During this phase of the analysis the key inputs to the model were identified using sensitivity analysis. These key variables were the basis for the uncertainty analysis in Phase II.

During **Phase II** of the analysis the model was adapted to use a Monte Carlo simulation process so that the expected range of ratepayer impacts could be calculated. Probability distributions were assigned to the key input variables identified in Phase I, and the model was re-run over 1,000 times using randomly selected values from the key variable input probability distributions. The result was a probability distribution for the ratepayer impacts (RPI) for each of the models analyzed.

The proposed scenarios, which are summarized Section 2.2 and the March 15th report, that were included in this analysis are listed below:

1. Continued Rebates / Solar Renewable Energy Credits (SREC) Scenario
2. SREC Only Scenario
3. Underwriter Scenario
4. Commodity Market Scenario

5. Auction-Set Pricing Scenario
6. 15 Year Tariff Scenario[1]
7. Hybrid-Tariff Scenario

In addition, this analysis included benchmarking of the ratepayer impacts of Renewable Portfolio Standards (RPS) in other states. This goal of this exercise was to gather data on ratepayer impacts to date in states where RPS policies have been in place for some time.

In assessing the ratepayer impacts of potential solar market transition strategies, it is essential to consider all of the potential benefits including those benefits that may be hard to quantify, e.g., job creation, environmental benefits, etc. The Summit Blue Team reviewed and commented on the applicability of a variety of studies that have examined additional impacts of RPS policies both in New Jersey and in other states.

This analysis focused only on one aspect, ratepayer impacts (RPI), of the proposed transition models. It is essential that reader bear in mind that there are other equally important aspects of the scenarios that should be considered. The next section recaps these other criteria and issues that need to be considered alongside the ratepayer impacts of the proposed models. More details on these criteria and issues can be found in the March 15th report.

1.1 Assessment Criteria for Transition Options

The objective of this analysis is focused specifically on the ratepayer impacts of the solar market transition options. However, the ratepayer impacts are just one of the criteria that should be used to evaluate the transition options.

The Board of Public Utilities' Office of Clean Energy has indicated that, as part of its review of a draft of this report, issues were raised regarding whether the Board of Public Utilities currently has the legal authority to implement the tariff or hybrid-tariff models discussed in this report. The Office of Clean Energy has indicated that the Board will consider this issue as part of its review of the options discussed in this report in its ongoing proceeding. The purpose of the analysis was to review a range of options for renewable incentives in New Jersey for comparative purposes.

In our March 15th report the strengths and weakness of the seven proposed solar market transition options were analyzed. In order to objectively evaluate the merits of these options, each option was reviewed using a consistent set of criteria that reflect the priorities of OCE and market stakeholders and that are consistent with elements present in the most successful solar markets. OCE's guiding principles for the market transition (see text box) formed the primary basis for developing the list of criteria used in the March 15th report. The criteria were grouped into categories that represent the most fundamental areas of interest in assessing the merits of each strategy.

[1] This is the model referred to as "full tariff model" in earlier report. In that report, the key distinction was between full/partial reliance on tariff revenue for return on project investment, rather than length of tariff commitment.

The primary categories include:

- Sustained orderly development
- Transaction costs
- Ratepayer impact
- Support for other policy goals

These primary criteria, and the associated secondary criteria, are described briefly below.

OCE Guiding Principles for Solar Market Transition:

- Achieve the rapid growth that is needed to meet the RPS goals. Facilitate project development and sales of systems. Ensure that closing a sale is simple and quick. Ensure that projects can be financed. Allow growth to be accelerated or slowed when needed.
- Achieve the lowest possible cost to ratepayers for a given amount of effective capacity and the lowest possible transaction costs.
- Ensure an efficient, transparent, and auditable process that can provide tools for policy goals, such as opportunity for different sizes and types of projects (large & small, private & public, etc.).
- For utilities, suppliers, and other market participants, minimizes regulatory risk, as appropriate, minimizes the administrative burden, and maximizes investor confidence in the market place.
- Ensure compatibility with regional markets and insuring adequate sources of supply.
- Allow all interested parties to participate.
- Support congestion relief.
- Support New Jersey's State Development and Redevelopment Plan.
- Require low implementation costs.
- Minimize the regulatory risk of investments in renewable energy systems.

Source: White Paper Series: New Jersey's Solar Market Transition to a Market-based REC Financing System, p. 5.

1.1.1 Sustained, Orderly Market Development

The overall goal of the RPS, and of the current incentive structure, is to develop a robust and sustainable market for renewable energy in New Jersey. This requires a clearly established plan for market growth. Such a plan will build investor confidence while still allowing the market to grow rapidly enough to meet the aggressive RPS goals.

1. **Facilitate rapid growth (to meet RPS targets)**

   The incentive program needs to be able to manage the rapid growth rates mandated by the annual RPS goals. A market transition strategy that requires a long ramp-up period, or that doesn't provide a sufficient level of financial support to stimulate PV development among classes of consumers that extend beyond the early adopters would not rate well for this criteria.

2. **Program readily adaptable to changing market conditions**

   Ideally, the natural mechanisms in the market would facilitate a rough balance between supply and demand, but since any incentive program will introduce some level of market distortion, it is critical that the program possess elements of flexibility that will enable it to adapt in response to changing market conditions. Changing market conditions might include an under- or over-supply of SRECs, or a dramatic breakthrough in technology or price. Examples of ways that an incentive program can adapt to changing market conditions include conducting a periodic review of the appropriateness of incentive levels, or tying incentive levels to some market index.

   This criteria is closely related to that of economic efficiency, and both are of critical importance to the effectiveness of an incentive program. In both cases, the goal is to ensure that incentive levels coincide with the level of support necessary to stimulate the amount of development required of the RPS goals. Structuring a program to adapt to changing market conditions is one way to ensure that projects are not over or under-subsidized.

3. Compatible with regional markets

Stability of the market for RECs will be tied to its size and liquidity. Compatibility and fungibility of RECs across regional (and eventually, possibly national) markets will add stability to the New Jersey market. It will also force New Jersey prices in line with regional prices.

New Jersey's RPS rules currently stipulate that only PV systems interconnected with a distribution system that supplies the State can create SRECs eligible for New Jersey RPS compliance.[2] Therefore, discussion of trading RECs from PV systems located outside New Jersey into the State is essentially irrelevant. However, to the extent that New Jersey SREC trading values can fall within the range of those in the surrounding region and other parts of the country, this will increase the liquidity of the New Jersey SREC market.

4. Maximize investor confidence

One of the most essential elements of building a successful market is developing investor confidence in the revenue stream. A high level of investor confidence results in cheaper financing, and this in turn produces: greater availability of money, lower interest rates, longer contract terms and reduced discounting of future revenue streams. In the case of the New Jersey REC market, investor confidence seems to be focused on the merchant risk that systems face. **Merchant risk** is driven by:

a. **regulatory risk**—the risk that either the BPU or the legislature will reverse or amend an existing regulation or statute,[3] and

b. **price risk—**the risk that an over-supply of solar energy in any given period would cause the prices for SRECs to fall.

Any program design elements that can increase the certainty of projected future revenue streams and make the market more predictable will enhance investor confidence. Some program design elements that may enhance investor confidence include:

- Design a program that includes a well-defined structure and long-term plan.
- Attempt to establish contractual commitments that would withstand future changes in policies or market rules.
- Reduce the long-term economic time horizon of projects by means such as providing one-time upfront rebates, offering short-term incentive payment periods that enable projects to quickly recover their investment, or front-loading incentive payments so that projects will recover the majority of the investment over a shorter period than they otherwise would. Of course, this method has deficiencies in other areas since it will concentrate the impact on ratepayers.

A more detailed discussion on risk and risk allocation is included in Section 1.2.1 below.

[2] New Jersey RPS Rules: N.J.A.C. 14:8-2.9 (d).

[3] In fact, regulations passed by NJ BPU need to be revisited every 5 years. This does not create an atmosphere of certainty among commercial lenders. Executive Order 66 (1978).

5. **Facilitates self-sustaining market**

   Ideally, the market mechanisms would allow the government influence to be subtle enough to create minimal distortion, and to permit the government role to gradually diminish without disrupting the ongoing trades. Historically, investment- or capacity-based incentive systems have not had much success in promoting sustainable markets. For this reason, more attention today is placed on production-based incentive systems, which encourage technical and economic efficiency in both the system design and in the financial structures.

1.1.2 Transaction Costs

1. **Ensure transparent, auditable process**

   Any successful market needs to have mechanisms that prevent fraud and misbehavior on the part of the traders. In the case of the SREC market, these would include transparent pricing and fully auditable processes, along with verified production. Either the SREC trading system or the PJM GATS would fulfill the need to provide auditable SREC transactions. However, in some market transition proposals, elements exist that would require monitoring and are less readily audited than the SREC transactions themselves. Also, there are clear differences among the proposals in the area of price transparency, since the SREC trading system provides price transparency but PJM GATS does not. To the extent that a proposal recommends using one system versus another, the issue of price transparency must be considered.

2. **Program design encourages simple efficient project logistics**

   One of the primary functions of any trading mechanism is to bring together willing sellers and buyers and allow them to consummate their transaction efficiently. The more effectively this process works, the more liquid the market becomes. An ideal market structure would not require complex ownership structures or contractual arrangements in order for projects to take advantage of incentives. Furthermore, it would be flexible in nature to enable future innovations to take effect.

3. **Low administrative burden**

   This criteria pertains to the overall administrative burden or "hassle factor" imposed on market participants such as project owners, installers, and administrative entities. While some level of administrative costs is essential for any effective, well-monitored program, program designers should strive to keep administrative elements to a minimum and to look for opportunities to maximize administrative efficiency (i.e., automatic tracking of all system production data would minimize administrative burdens both for project owners and for program administrators). In general, minimizing paperwork and approval processes associated with an incentive structure is important in that it enables a greater amount of funds to be spent on actual system construction.

1.1.3 Ratepayer Impact

1. **Economically efficient (no over- or under-subsidization)**

   In order to use the ratepayer monies most efficiently, the program should provide only the incentive level required to keep the market supply and demand in balance. An ideal market structure will include mechanisms to enable incentive outlays to change in response to the dynamic economic needs of market participants. This criteria is particularly important given the fact that certain project types (i.e., commercial projects in which the owner possesses a large tax burden) can quickly achieve a positive cash flow in the absence of incentives, while the viability of other projects (i.e., residential and many public projects with less ability to take advantage of tax incentives) is much more dependent on the availability of state incentives.

2. **Minimize regulatory risk**

   As described above, minimizing regulatory risk is closely related to improving investor confidence. Reducing regulatory risk will reduce financing costs and thus, the incentives required to stimulate project development. Eliminating regulatory risk in New Jersey would be impossible. However, certain program design elements can make the market more predictable and appealing for investors.

3. **Low program implementation costs**

   This criteria is related to "low administrative burden" but pertains more broadly to the overall implementation costs associated with various program alternatives. Drivers of implementation costs include incentive levels, and the amount of necessary program implementation infrastructure (i.e., monitoring systems and/or staff support). While administrative and implementation costs could not be assessed within the scope of this assignment, certain assumptions were made regarding the relative magnitude of program implementation costs. This criteria is important because all of the money spent on creating program infrastructure or administering an incentive program is money that cannot be used to support actual PV project development.

1.1.4 Support for Other Policy Goals

1. **Equity of opportunity to participate (i.e., system size)**

   A well-designed incentive program will offer appropriate types and levels of incentives to serve the needs of a wide variety of system sizes, participant types (i.e., residential, commercial, etc.), and ownership structures. Low-income and small business participants should be included in this diversity of needs served, as these ratepayers contribute to rebate program funding, but typically do not possess the means install PV.

2. **Ability to encourage development by target categories**

   An ideal program will stimulate PV development among customer classes which represent various policy goals by providing greater incentives to those customers.

3. **Congestion relief**

   One of the benefits of distributed generation is the relief of transmission and distribution system congestion. Ideally, the program incentives would particularly encourage development of systems in locations where the grid support is weakest.

1.2 Additional Market Transition Issues

The BPU has established RPS goals for renewable energy production in its rules. To date, much has been accomplished towards these goals; however, over the next 13 years there will need to be a significant amount of investment to meet the 2021 RPS goals. The Board has initiated a proceeding to determine which of these proposed scenarios will achieve this overall objective while at the same time providing the structure for a sustainable renewable energy market in New Jersey.

To meet the RPS, the system needs to move away from investment-based (sometimes called capacity-based) incentives that pay owners for installing systems, not for producing energy, and towards production-based incentives that reward owners for producing energy. This type of incentive also helps drive to the most cost-effective systems, which will also help to lower the cost to the ratepayers.

However, minimizing ratepayer costs can come into conflict with other objectives. For example, promising fixed tariffs for the renewable energy power produced will minimize the cost to ratepayers, but is very unlikely to leave behind a thriving market for renewable energy systems. On the other hand, forcing the system owners to build their plants on a “merchant” basis—without any long-term off-take agreement—is unlikely to produce the levels of new investment required to meet the RPS.

Reliable and predictable off-takes of both energy and SRECs will be critical to drawing the investment needed for New Jersey to meet its RPS. By nature, renewable energy deals require a large capital investment, which is then recouped by selling the energy and SRECs from the system. (This is not dissimilar to buying an “annuity” which pays out over a period of years.) If these annual revenues are perceived as potentially unreliable, the investment is not a good risk for the investors, and they will either walk away, or at best, fund it at a high premium.

Fortunately, this is not an “either-or” game. There are a variety of ways to share the “risk” between the ratepayers and the investors. Most of these techniques also will allow the State to gradually reduce its incentives on a well-defined and predictable basis. The intent of these techniques should be to provide a stable, transparent, and predictable market for the system owners and investors. In this way, they can gain confidence in the market, and as the incentives are gradually reduced on projected schedule, they can plan and predict their incentive revenues with enough confidence to continue investing.

1.2.1 Risk Allocation

Risk allocation is one of the more important elements of project finance. It is an axiom of modern non-recourse financing that risk should be allocated to the party best able to manage it. So, for example, risk of construction delays would be assigned to the general contractor, and risks associated with equipment failure or design would be assigned to the equipment supplier.

In the case of photovoltaic systems, there are three primary categories of risk involved. These categories are summarized in Table 1-1 and described in the following paragraphs.

Table 1-1. Project Risk Categories

Risk Categories	Description of Potential Risks
Equipment Risk	• Poor quality equipment • Poor-quality installation
Performance Risk	• A “bad” solar year (low insolation level) • Shading • Insufficient cleaning of modules
Merchant Risk	• Volatility in SREC market pricing • Volatility in electric rates • Exposure to spot-market pricing for SRECs • **Regulatory risk** (a sub-category of merchant risk) resulting from the uncertainty created by the possibility of changes to rules governing market.

The first category is **equipment risk**. This is the potential for the equipment to not function as designed or to be mis-installed in such a way that it can’t function correctly. This is normally covered by warranties offered by the installer and/or the manufacturer. The State is currently trying to minimize the equipment risk by requiring warranties on the installed systems.

The second major class of risk is **performance risk**. Performance risk includes a number of related causes that prevent the system from delivering the expected amount of energy. The most obvious one, of course, is insolation level. In a “bad” solar year, the system will not produce as much energy as planned, and the revenues will be lower than modeled. Other examples of performance-lowering factors might be tree limbs or other greenery that begins to shade the solar panels for part of the day or failure to clean the panels regularly. This class of risk is naturally borne by the system owner, since s/he is best positioned to manage them.

The third class of risk is **merchant risk**. Merchant risk is the salability of the output of the system—power and SRECs—into the market. For net-metered PV systems, sale of the power is generally not considered an issue.[4] However, the sale of SRECs may be a larger and more important stream of revenue, and it is exposed to a variety of merchant risks. For example, new markets like the NJ SREC market are typically small and thinly traded. As a result, SREC values can be subject to rather wild volatility created by seemingly small disturbances. For example, the system owner may be forced to sell into a “down” market that would negatively impact the revenue stream.

A major factor affecting the merchant risk of SRECs is **regulatory risk**. The entire market for SRECs has been created artificially by the State by creating the RPS. Any changes to the RPS goals, or the rules for buying and selling SRECs could result in a major dislocation in the SREC market. Regulations passed by NJ BPU need to be revisited every 5 years.[5] There is a risk that either the BPU or the legislature will reverse or amend an existing regulation or statute; therefore, it is important to explore strategies for managing this type of risk, such as long term tariff agreements.

Another factor creating merchant risk is the term of the contract for SRECs. Ideally, lenders would like to see iron-clad, long-term contracts for the SREC output. However, the entities that need SRECs to satisfy

[4] Although, like other policies and market rules upon which solar investments depend, net metering policies are potentially subject to change during the investment time horizon for a PV system.

[5] Executive Order 66 (1978)

the RPS, the LSEs, are not typically interested in entering into a contract longer than three years since that is the contract term for the current BGS auction system. *This inability to secure long-term contracts creates uncertainty in the market and discomfort for lenders.*

One of the reasons that risk is so important is the effect that it has on financing. Lenders like to see that their money is well-shielded from risks over which they have no control. As the risk level rises, loans become both more difficult to find and significantly more expensive.

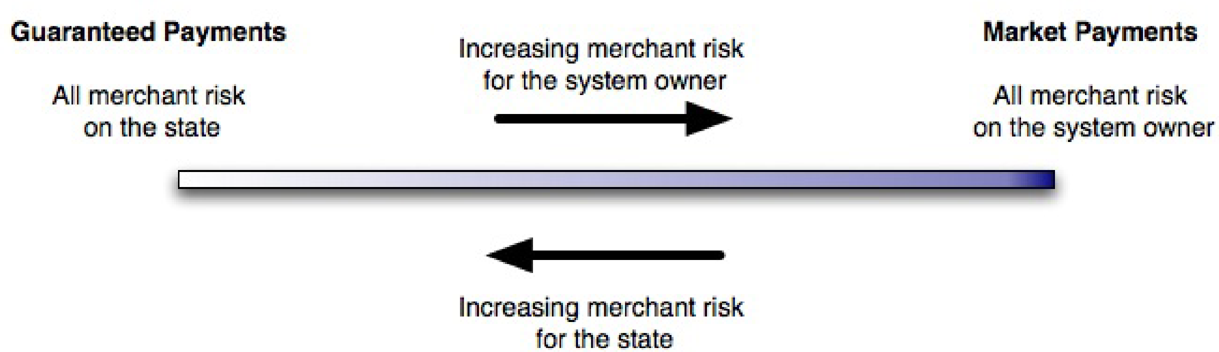
The impact of risk on financing is more evident for large systems where the loans are substantial and the lenders are likely to be more sophisticated about issues of risk. However, it is not absent for smaller and residential systems. Research has confirmed that some residential systems are being funded by home equity loans. In this case, the value of the home is used to secure the loan and the lender is indifferent to the associated revenues. However, it is important to note that now the homeowner is shouldering both the performance and the market risk for the PV system.[6]

New Jersey Risk Allocation

Under the CORE program as it has existed to date, the up-front rebate offered by the State has reduced a great deal of the financial risk associated with solar projects. This limited risk profile has enabled rapid industry and market growth. However, in a post-rebate environment, the risk profile of projects is likely to shift dramatically. Project investors will need to absorb more of the project's financial and performance risk. A number of industry experts agree that the financial community is ready and willing to serve the needs of solar project investors, but they note that this absorption of risk by the financial community will come at a very high cost.

In fact, this question of merchant risk is not an "either/or" issue, but rather one that exists on a spectrum, as illustrated in Figure 1-1 below. The different solar market transition options possess very different risk allocation portfolios. Although some of the transition options that have been offered focus the risk on one end of the spectrum or the other, there are a number of proposed options that provide a more balanced risk allocation. A determination about the appropriate allocation of risk will have a significant bearing on the framing of a suitable transition strategy for the State.

Figure 1-1. Merchant Risk Spectrum



[6] As well as the equipment risk, if s/he doesn't have a strong warranty.

While this report will focus specifically on the ratepayer impacts of the solar market transition options, it is important that each option should be evaluated against all of the evaluation criteria and that careful thought is given to the market issues when selecting an viable approach for the solar market transition. The assessment of the transition options relative to the other criteria can be found in the March 15th report. The reader is encouraged to consider this ratepayer impact analysis along with the other evaluation criteria assessed in the March 15th report.

1.3 Organization of Report

The remainder of this report is organized as follows:

Section 2 provides overview of the ratepayer (RPI) model and modeling assumptions.

Section 3 presents the results of the RPI modeling and the Monte Carlo Simulation.

Section 4 provides the results of the ratepayer impacts benchmarking analysis.

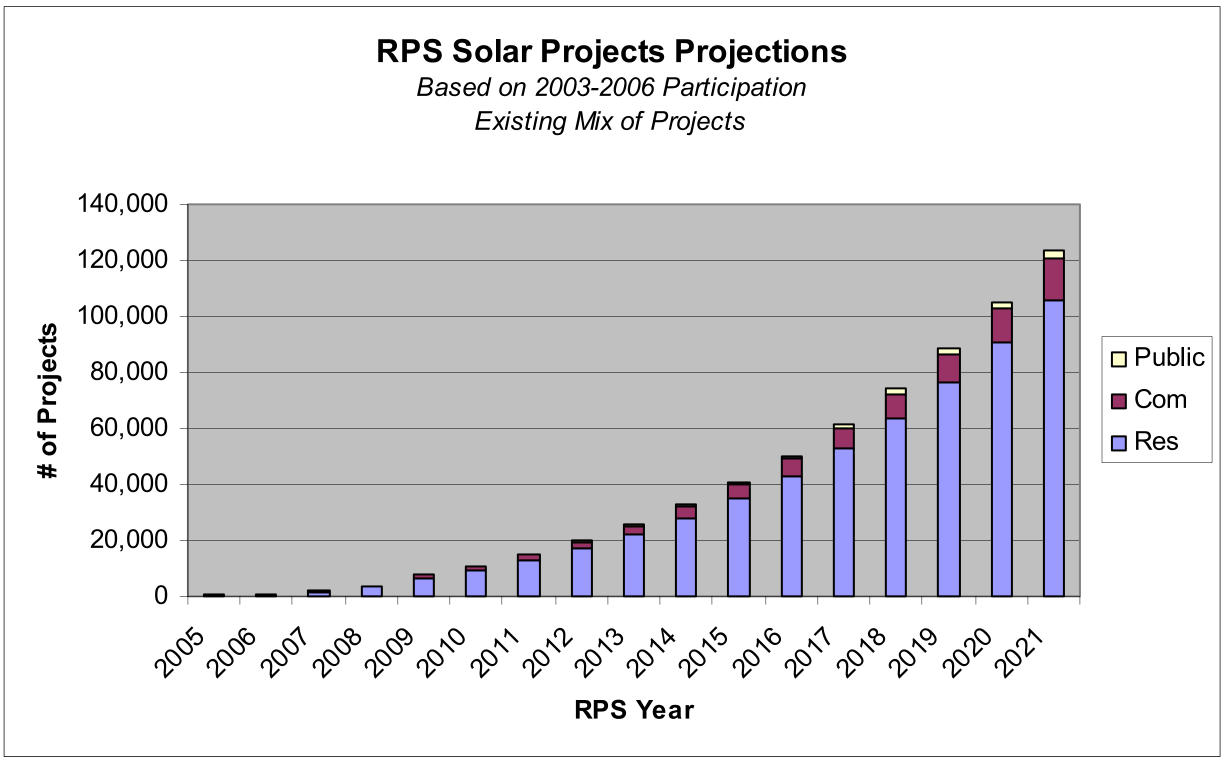
Section 5 provides an overview of the benefits associated with the ratepayer impacts of the proposed models.

2. OVERVIEW OF THE MODEL AND ASSUMPTIONS

This section describes RPI modeling approach and assumptions. The seven transition models are summarized in this section; however, more details and analysis of these models can be found in the March 15th report.

New Jersey has one the most aggressive solar set asides of any State RPS; 2.12% of annual retail electricity sales must be provided by solar PV project by 2021. Figure 2-1 presents the cumulative projected number of projects that will be needed to meet the solar RPS requirement by 2021, based upon the historical average project size and project type distribution. In order to meet this aggressive target the State will need to penetrate solar PV market beyond the early adopters and provide an attractive investment to consumers.

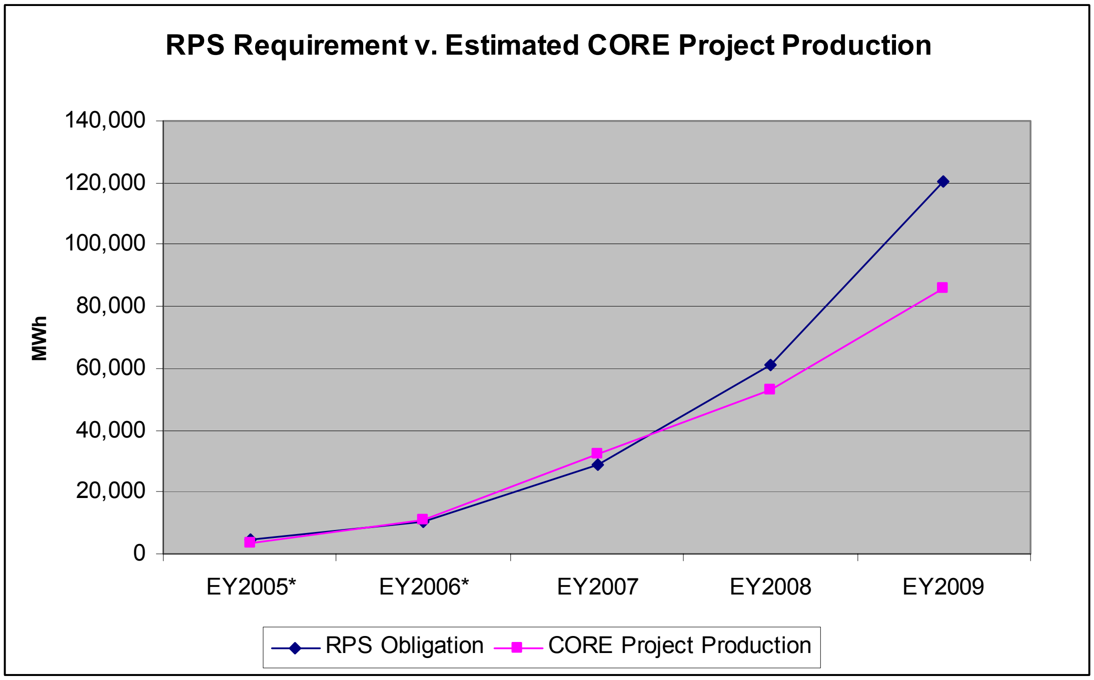
Figure 2-1. RPS Solar Project Projections



Source: 2003-2006 Average CORE project size by project type and distribution by project, PJM NJ retail sales projects and the RPS Solar requirements.

Figure 2-2 presents OCE's estimate of the production from the CORE program through Energy Year 2009. As the graph shows, the production from the CORE is estimated to be less than the RPS requirements. The data for EY2005 and EY2006 are actual CORE program production. The RPS requirements are net of the exempted 2003 BGS load.

Figure 2-2. OCE's Estimate of CORE Program Shortfall



2.1 Modeling Approach

The following approach was used for calculating the ratepayer impacts (RPI):

Step 1: The project economics of each proposed scenario was modeled. Using these models the annual incentive levels (rebates, SRECs, or tariffs) were determined such that the project economics met a targeted internal rate of return (IRR). Targeted IRR was selected so that the project economics were attractive to consumers beyond the early adopters.

Step 2: The annual incentive levels determined in Step 1 were applied to the annual solar RPS requirements to calculate the annual solar RPS incentive costs. The annual solar RPS requirements were determined by applying the solar RPS goals to the projected annual New Jersey retail sales. This analysis was performed from 2008 through 2035 to account for the full stream of incentives for projects built in 2021, the last year of the RPS. All of the scenarios used this analysis period to facilitate comparison across the proposed scenarios.

Step 3: The estimated up-front and annual administrative costs for each of the proposed scenarios were added to the annual solar RPS incentives costs to calculate the total annual cost of meeting the solar RPS requirements. The total annual solar RPS costs were discounted to 2007 dollars using an assumed discount rate. This discounted, present value, of the solar RPS costs is the total amount of funds that will need to be spent from 2008-2035 to achieve the solar RPS requirements.

Step 4: The RPI for each proposed scenario was calculated by dividing the present value of the total solar RPS costs calculated in Step 3 by the projected amount of total retail sales (MWh) in New Jersey for all ratepayers over the analysis period. This step results in a RPI in terms of dollars per kWh.

Targeted Internal Rate of Return (IRR)

The first step of the project economic analysis is to determine the targeted IRR for each of the project types. Primary research was conducted to understand how the market perceives the IRR targets and the market conditions were judged to come up with estimates of the IRR.

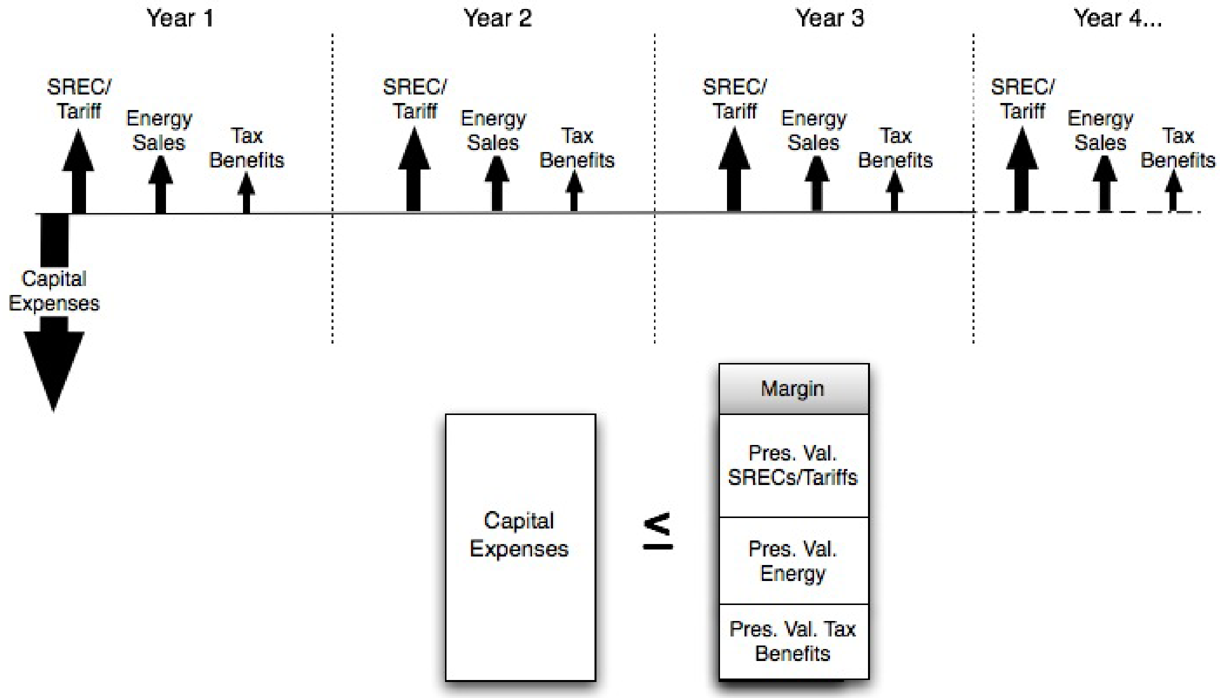
If New Jersey investors are to accept the level of risk offered by the New Jersey solar markets, they must see an acceptable level of return on investment. This requirement speaks to a variety of policy decisions, ranging from the structure of the incentive program itself, to the setting of SACP levels. Anything that reduces the investors' upside, or increases their risk, will reduce their willingness to invest.

As with the earlier discussion around project risk and finance, different classes of investors have different risk/return appetites. Solar industry experts report that residential consumers are most concerned with the simple payback period for their solar investment and that to attract interest beyond the subset of early adopters, it is important to show simple payback in the range of five to seven years. These are equivalent to an internal rate of return (IRR) of 19% and 13% respectively, assuming a 20-year economic life.[7] We adjusted the IRR targets provided by the project developers to be more conservative.

Figure 2-3 provides a cash-flow schematic. The initial capital cost is on the left, followed by a series of revenue streams from the incentive or tariff payments, the energy payments (or retail electricity payments offset, in the case of net-metered systems), and the tax advantages accruing to the owner over a period of years.

[7] Misunderstanding of the relationship between rate of return and simple payback periods is fairly rampant in this industry. Although simple payback is the easiest to calculate (capital cost divided by annual revenues produced), it does not provide a measure that allows comparability to other investment opportunities, which are typically expressed in percentage returns. By contrast the IRR (internal rate of return) calculates the rate of return that exactly accounts for all of the costs and revenues over the expected life of the system. For example, it is not uncommon for unsophisticated customers to ask for simple paybacks of 2 or 3 years, which would provide IRRs (50% and 33%) much larger than nearly any other investment with a comparable level of risk.

Figure 2-3. PV System Project Economics



The bottom of the figure illustrates that for the project to be successful, the present value of all of the revenue streams—including the incentives—must be larger than the initial capital outlay. The project developer must be able to recover enough revenue from the project quickly enough to make it profitable, or at least economically viable. This is problematic for PV projects, where the system is both expensive and the payback period is typically 20 years or more. Furthermore, since the market for SRECs is new and thinly traded, the potential revenues available from SRECs in the out-years are seen as uncertain. Therefore, these future SREC revenue streams are greatly devalued by the investment community. Project economics vary significantly across the range of prospective owners. For example, corporate entities with large tax burdens are capable of taking advantage of the Modified Accelerated Cost Recovery System (MACRS) and Corporate Tax Credit, which together can dramatically reduce the effective cost of a PV system.[8] Residential PV system owners can also benefit from a tax credit, representing 30% of the system cost up to $2,000.[9] However, public entities that are tax-free are normally unable to benefit from any tax incentives. However, public projects can benefit from tax incentives if they negotiate creative ownership arrangements or purchase power agreements with third-party entities, which is what we have assumed for this RPI analysis. Similarly, the cost per kW of PV systems decreases as the size of the system increases. Because of these variations, each class of project will be examined individually.

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[8] The MACRS enables corporate entities to recover solar investments through an accelerated 5-year depreciation schedule. The Business Energy Tax Credit also provides commercial and industrial solar project owners with a 30% tax credit. This incentive would have expired at the end of 2007, but was recently extended through 2008 by Section 207 of the Tax Relief and Health Care Act of 2006 (H.R. 6111). Further information on federal tax incentives is available through the Database of State Incentives for Renewable Energy, http://www.dsireusa.org/library/includes/genericfederal.cfm?currentpageid=1&search=federal&state=US&RE=1&EE=0. Or see next footnote.

[9] SEIA guide to Federal Tax Incentives for Solar Energy, Version 1.2, May 26, 2006. http://www.seia.org/manualdownload.php

Based upon discussion with the project developers and industry experience the Targeted IRR values were selected. It should be noted that these Target IRR are used as a starting point for this analysis and a wider range of Target IRRs are considered in the Monte Carlo analysis:

- ≤ 10 kW Private: 6% IRR (10 year payback)
- >10 kW Private: 12% IRR (6 year payback)
- Public: 8% IRR (8 year payback)

Figure 2-4 shows the project cash flow calculations. These calculations were performed for each project type and for each scenario. The incentive level was set so that the Targeted IRR were achieved for each project type.

Figure 2-4. Schematic of Project Cash Flow Analysis

	Year 1	Year 2	Year 3	Year 4
A	**- Installed Costs**			
B	**+ Electric Savings**	**+ Electric Savings**	**+ Electric Savings**	**+ Electric Savings**
C	**+ Rebate**			
D	+ SREC Sales	+ SREC Sales	+ SREC Sales	+ SREC Sales
E	- O&M Costs	- O&M Costs	- O&M Costs	- O&M Costs
F	**= Pre-Tax Cashflow (D-E)**	**= Pre-Tax Cashflow (D-E)**	**= Pre-Tax Cashflow (D-E)**	**= Pre-Tax Cashflow (D-E)**
G	Pre-Tax Cash-flow (F)	Pre-Tax Cash-flow (F)	Pre-Tax Cash-flow (F)	Pre-Tax Cash-flow (F)
H	-MACRS	-MACRS	-MACRS	-MACRS
I	=Taxable Income (F-H)	=Taxable Income (F-H)	=Taxable Income (F-H)	=Taxable Income (F-H)
J	Taxable Income (I)	Taxable Income (I)	Taxable Income (I)	Taxable Income (I)
K	x Tax Rate	x Tax Rate	x Tax Rate	x Tax Rate
L	= Gross Tax (I x K)	= Gross Tax (I x K)	= Gross Tax (I x K)	= Gross Tax (I x K)
M	- Federal Tax Credit			
N	**= Net Taxes (L-M)**	**= Net Taxes (L-M)**	**= Net Taxes (L-M)**	**= Net Taxes (L-M)**
O	**= Net Cashflow (A+B+C+F+N)**	**= Net Cashflow (A+B+C+F+N)**	**= Net Cashflow (A+B+C+F+N)**	**= Net Cashflow (A+B+C+F+N)**

2.2 Summary of the Scenarios Included in Analysis

The following are brief summaries of the proposed models and the notes on the project economic analysis. For full descriptions and analysis of these models, please see the March 15th report.

2.2.1 Rebate/SREC

Description: Closest scenario to current CORE program offering. Scenario uses a combination of rebates and the SREC market to provide the incentives to meet the targeted IRR.

Incentives: Uses current rebate levels, decreasing at a rate of 1.4% annually. The remaining incentive comes through the SREC market. This scenario assumes no SACP cap which allows the SREC value to float to meet targeted IRR by project type.

Risk Allocation: Risk is shared between the State and the project owner.

Expected RPI: Since risk is shared, the RPI is expected to be high due the incentives being paid up front.

Controlling Risk: Risk is driven by lack of mechanism for establishing long-term contracts for the SREC portion of the incentives.

2.2.2 SREC Only

Description: Most pure market Performance-Base Incentive (PBI) of the proposals. Scenario used the SREC market to provide the incentives to meet the targeted IRR.

Incentives: SREC value varies to produce the target IRR.

Risk Allocation: Developer bears all incentive cash flow risk.

Expected RPI: This scenario is expected to produce a high RPI due to risk premium that developers would assign to incentive cash flow.

Controlling Risk: Risk is driven by lack of mechanism for establishing long-term contracts for the SREC portion of the incentives.

2.2.3 Underwriter Model

Description: This scenario provides a 15 year SREC floor for the SREC prices. This provides securitization for the project. The underwriter would have a maximum exposure proportional to the SREC floor value. It is assumed that there is an active SREC market, and the SRECs sold in the market would provide the incentives under this scenario.

Incentives: SREC value varies to produce the target IRR.

Risk Allocation: Incentive cash flow risk is shared between developer and State.

Expected RPI: Incentive cash flow risk for developer is lower than SREC Only model.

Controlling Risk: Although the Model provides a 15 year SREC floor the long-term value of the SREC, driven by the market, is still uncertain. There is also additional uncertainty regarding the establishment of the underwriting fund and identifying a willing/appropriate underwriter entity.

2.2.4 Commodity Market Model

Description: This scenario provides incentives through the SREC market for all projects and includes a 15 year SREC Floor using the underwriter approach. For projects less than 100 kW, the current rebates would continue for three years to help the market through the transition. After three years, the rebates would be discontinued and the incentives would come solely from the SREC market.

Incentives: Based on SREC values calculated in Underwriter model.

Risk Allocation: Developer bears all incentive cash flow risk after the first 3 years.

Expected RPI: Addition of rebates causes a higher IRR and higher RPI than Underwriter model.

Controlling Risk: Although the Model provides a 15 year SREC floor the long-term value of the SREC, driven by the market, is still uncertain. There is also additional uncertainty regarding the establishment of the underwriting fund and identifying a willing/appropriate underwriter entity.

2.2.5 Auction Model

Description: An auction process is used to produce a fixed five-year SREC value for projects initiated in each auction year. Five year SREC contracts are used to provide securitization for project.

Incentives: SREC value varies for projects initiated in each new project year to produce the target IRR.

Risk Allocation: Incentive risk profile for developers is very low. States bears the bulk of the incentive risk.

Expected RPI: Relatively low RPI, but very high SREC prices due to short time frame of the incentives.

Controlling Risk: Risk is driven by lack of mechanism for establishing contracts longer than 5 years for the SRECs.

2.2.6 15 Year Tariff Model[10]

Description: A 15 year tariff is created to provide incentives. The tariff provides securitization for project.

Risk Allocation: Incentive risk premium for developers is very low (no dependence on SREC revenue). The States bears the incentive risk.

Incentives: Tariff is an adder to current value of existing electric rate offset by PV generation.

Expected RPI: Medium RPI due to longer term.

Controlling Risk: The incentive prices are not market driven and could result in either incentives that are too high or too low.

2.2.7 Hybrid-Tariff Model

Description: A 10 year tariff combined with the SREC market. The tariff portion of the incentive provides some securitization for project.

Incentives: Tariff rate set to 37.5% of 15 year Tariff Scenario with SREC provide the remaining incentive. This allocation of incentives was described in the original proposal.

Risk Allocation: Risk allocation is between SREC Only and tariff model and is, therefore, shared between the developers and the State.

[10] Referred to as the full tariff option in the March 15, 2007 report.

Incentives: Modeled tariff as an adder to current electric rate plus the SREC market provides the additional incentives over and above electricity costs offset by PV power generation.

Expected RPI: RPI should be greater than 15 year Tariff and less than SREC-Only, but will vary depending upon where the tariff rate is set

Controlling Risk: Risk is driven by lack of mechanism for establishing long-term contracts for the SREC portion of the incentives. A portion of the incentive prices are not market driven and could result in either incentives that are too high or too low.

2.3 CORE Program Data Summary

The CORE program database was one of the primary data sources for this analysis. Data through the end of 2006 was analyzed to determine:

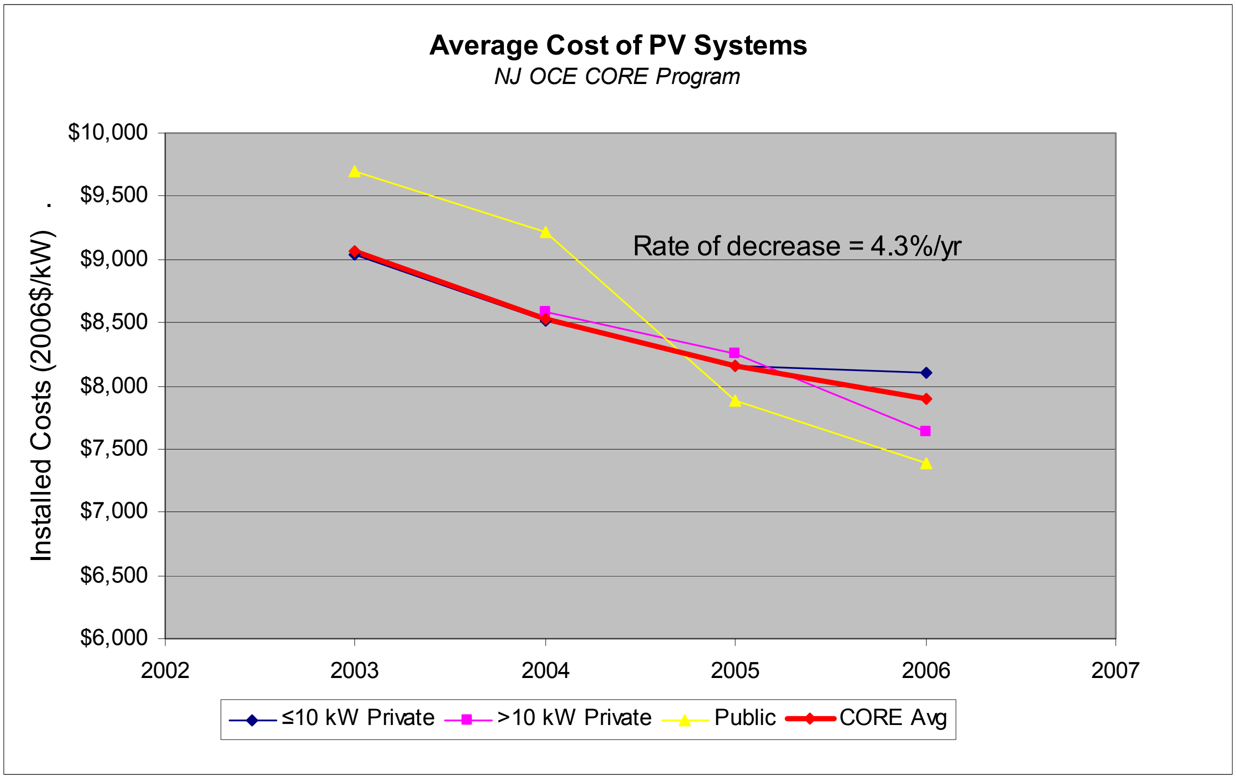
- The average cost per kW of the installed PV system,
- The average installed PV system size, and
- The distribution of installed system by project type.

The average cost of a PV system installed in the CORE program has decreased an average of 4.3% per year over the past three years (Table 2-1 and Figure 2-5). The decline in costs over this period is most likely due to project developers working out delivery efficiencies and a result of increased competition among PV project developers.

Table 2-1. Average Cost of PV System (2006$/kW)

	2003	2004	2005	2006	Avg. Annual Change	2008 Projected
≤10 kW Private	$9,033	$8,511	$8,163	$8,101	-3%	$7,553
>10 kW Private	-	$8,580	$8,259	$7,638	-5%	$6,822
Public	$9,692	$9,213	$7,885	$7,391	-8%	$6,268
CORE Avg	$9,071	$8,532	$8,161	$7,901	-4%	$7,236

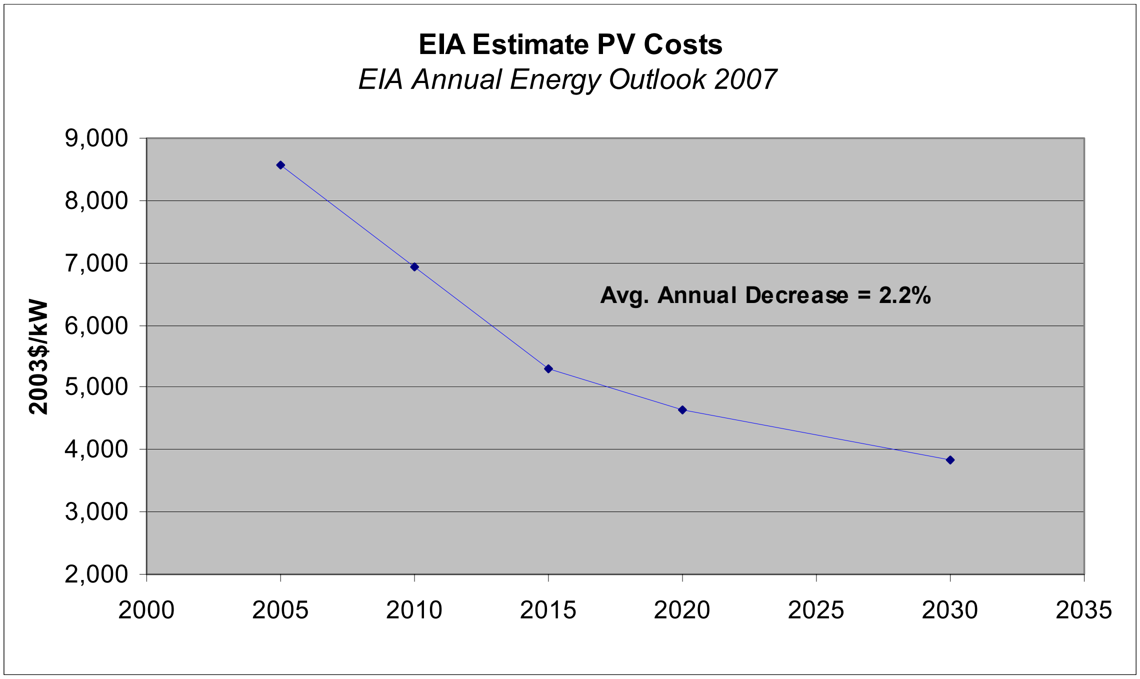
Figure 2-5. Average Cost of PV System in CORE Program (2006$/kW)



This decrease in PV project costs may not be sustainable over the fourteen years of the RPS, i.e., through 2021. Therefore we used what we believe to be a more sustainable decrease in PV costs estimated by the Energy Information Agency (EIA) (Figure 2-6).[11]

[11] "Energy Information Administration/Assumptions to the Annual Energy Outlook 2007 – Residential," page 22, Table 9.

Figure 2-6. EIA Estimate of PV Costs



A majority (86%) of the PV projects installed in the CORE Program from 2003-2006 were ≤ 10 kW Private, typically residential, projects (Table 2-2). However, the ≤ 10 kW Private project only represent 46% of the installed capacity (kW) from 2003-2006 (Table 2-3). As can be seen in Figure 2-7, the project type mix has been shifting towards more >10 kW Private projects. However, this trend will depend upon which scenario is selected going forward. For the purpose of this analysis, the average project type capacity distribution in Table 2-3 is used to calculate the weighted average RPI.

Table 2-2. CORE PV Projects 2003-2006

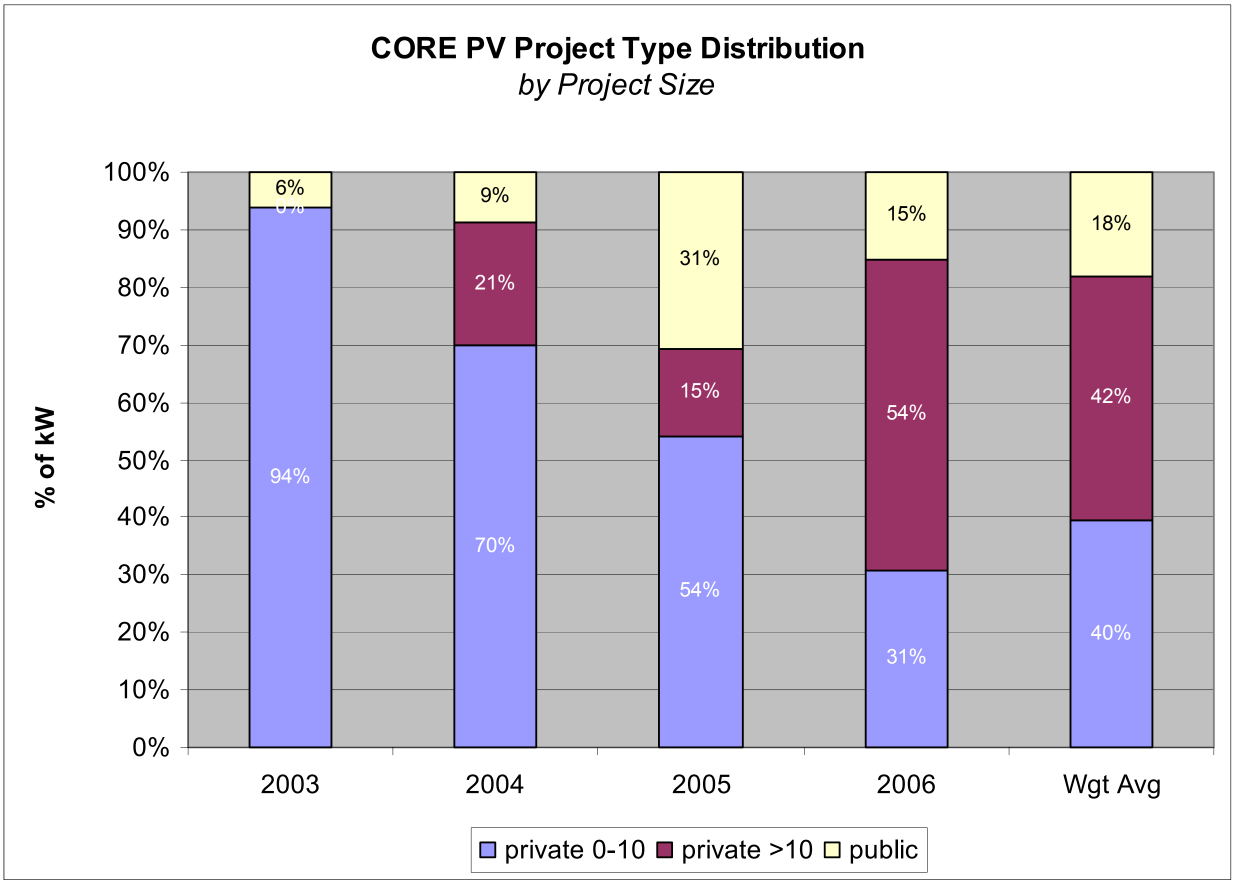
	2003	2004	2005	2006[12]	2003-2006	
Project Type	Projects	Projects	Projects	Projects	Projects	% Projects
≤ 10 kW Private	33	259	442	822	1,556	86%
> 10 kW Private	-	16	35	162	213	12%
Public	2	7	16	17	42	2%
Total	35	282	493	1,001	1,811	100%

[12] 2006 CORE program data provided by CORE Program Market Administrator on April 5, 2007.

Table 2-3. CORE Installed PV kW 2003-2006

Project Type	2003	2004	2005	2006[13]	2003-2006	
	Total kW	Total kW	Total kW	Total kW	Total kW	% Projects
≤ 10 kW Private	166	1,501	2,979	5,522	10,168	40%
> 10 kW Private	-	459	847	9,621	10,927	42%
Public	11	185	1,699	2,726	4,621	18%
Total	177	2,144	5,526	17,870	25,717	100%

Figure 2-7. CORE Program PV Project Type Distribution (2003-2006)



The average CORE program PV project size by project type was also calculated using the CORE database. Table 2-4 presents the average PV project size by year. Although there appears to be a trend towards larger >10 kW Private projects, depending on the future incentive structure this trend may not continue. To be conservative the 2003-2006 average was used in the analysis.

Table 2-4. CORE Average Project Size (kW)

Project Type	2003	2004	2005	2006[14]	2003-2006
≤ 10 kW Private	5.04	5.79	6.74	6.72	6.53
> 10 kW Private	-	28.67	24.21	59.39	51.30
Public	5.50	26.41	106.21	160.36	110.03

[13] 2006 CORE program data provided by CORE Program Market Administrator on April 5, 2007.

[14] 2006 CORE program data provided by CORE Program Market Administrator on April 5, 2007.

2.4 Model Inputs

This section presents the inputs that were used in Phase I of the analysis. For this phase of the analysis base or standard inputs were chosen. It is difficult to know the value of many of the standard variables with a high degree of certainty. Therefore the standard inputs were varied to determine the sensitivity of the model to the assumptions. The inputs were varied typically from 50% to 200% of the standard value. The key inputs to the sensitivity of the model were identified through this analysis. In Phase II of the analysis the key inputs were assigned probability distributions to reflect the uncertainty in these variables.

2.4.1 General Assumptions

There are many external factors that can change the RPI of these models. Our goal was not to try and model all these external factors, but to make reasonable assumptions about these factors for each of the project types.

The general assumptions included:

- Incentive will track the change in PV installed costs. As PV installed costs decrease, the amount of incentive need to achieve the targeted IRR will decrease also.
- Federal incentives will decrease over time to match decreasing PV installed costs. This includes the investor tax credit for both business and residential consumers.
- Projects built after the first year of the analysis will seek a consistent IRR as federal incentives track down. A project built in 2021 will look for the same IRR on the project as a project built in 2008.
- For the calculation of the present value of the solar RPS cost, a Discount Rate of 10% was used. The discount rate is often considered equal to the cost of capital for the investor.
- Based on the Energy Information Agency projection, an annual 2.2% decrease in the cost of PV systems was used (see above).
- The projected 2008 New Jersey electric retail sales = 73,800,000 MWh.[15]
- Projected New Jersey electric retail sales annual growth rate = 1.5%.[16]
- Residential annual retail electric rate growth rate = 2.99%.[17]
- Commercial annual retail electric rate growth rate = 3.24%.[18]

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[15] New Jersey Solar Market Update, January 2007. The estimate of retail sales for the RPS goals does not include on-site generation and only includes retail sales to the customers of the regulated NJ electric utilities.

[16] PJM News Release, January 16, 2007. http://www.pjm.com/contributions/news-releases/2007/20070116-2007-load-forecast-report.pdf

[17] Average annual electric rates were calculated using annual retail sales and annual retail revenue data for New Jersey sector from the Energy Information Agency website. Annual retail electric rate growth rates were calculated from the annual electric rates. (2001-2005).

[18] Ibid.

2.4.2 Project Type Standard Inputs

The standard inputs used to conduct the project-level economic analysis for each of the evaluated models is presented in Table 2-5. As indicated and discussed above, many of the Standard Inputs come from the average project type values from the CORE database. Each input is described below.

Table 2-5. Standard Inputs

Inputs	***Project Type*** ≤10 kW Private	>10 kW Private	Public[19]
Project Distribution	40%	42%	18%
System Size (kWdc)	6.5	51.3	110.0
kWac	5.130	40.272	86.374
kWH/yr/kWac	1,000	1,000	1,000
Annual Energy Generation	5,130	40,272	86,374
Electric Rates	Residential	Commercial	Commercial
Install Costs (2006$) ($/kW)	$7,553	$6,822	$6,268
Construction Cost	$49,360	$349,999	$689,637
Production Factor (first year, kwhr/Wdc STC)	1.00	1.00	1.00
System Performance Degradation (%/yr)	0.50%	0.50%	0.50%
System Maintenance Costs ($/kWh)	$0.02	$0.02	$0.02
Federal Marginal Tax Rate	0.2	0.35	0.35
Rebates Taxable	FALSE	FALSE	FALSE
MACRS Eligible	FALSE	TRUE	TRUE
Targeted IRR	6%	12%	8%

Input Definitions:

Project distribution - % kW of installed projects by project type. Source: CORE Database project type distribution 2003-2006.

System Size (kW_{dc}) – the size of the installed system in kW DC at Standard Test Conditions (STC). Source: CORE Database average project size by project type 2003-2006.

kW_{ac} – the size of the installed system in kW AC. Conversion factor of 0.785 kW_{ac}/kW_{dc}.

$kWh/yr/kW_{ac}$ – Annual energy generated by the installed system per kW capacity of the system. Source: developer interviews.[20]

Annual Energy Generation (kWh) – Annual energy generated by the installed systems. Calculation = kW_{ac} x $kWh/yr/kW_{ac}$.

Electric Rates – the set of electric rates used to calculate the avoided retail cost of energy generated by system.

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[19] It is assumed that public projects are owned by private entities to maximize tax opportunities.

[20] For proposed models with performance based incentives, it is expected that the annual generation would be higher than models without a performance based incentive. However, data was not available to document this expected improved system performance, so all models use the standard input.

Install Cost (2006$) ($/kW) – the average cost per kW of the installed system by project type. Source: CORE Database average project costs by project type 2003-2006.

Construction Cost – the cost of the installed system. Calculation = Install Cost (2006$) ($/kW) x kW_{ac}.

Production Factor (first year, kWh/W_{dc} STC) – factor to compensate for the system ramping up during the first year of operation. It is assumed that the system will be fully operation during the first year.

System Performance Degradation (%/yr) – the annual degradation of the system due to normal use. Source: Industry standard.

System Maintenance Costs ($/kWh) – the annual costs per kWh for maintaining the system. Source: Industry standard.

Federal Marginal Tax Rate – estimate of the marginal tax rate of the project owner. Source: Summit Blue estimate.

Rebates Taxable – a logic variable for whether to treat the rebate as taxable. Source: IRS ruling has recently declared that state incentives are not taxable.[21]

MACRS Eligible – a logic variable for whether or not the project type is eligible for the modified accelerated cost recovery system (MACRS), i.e., accelerated depreciation. Only projects owned by commercial entities are eligible for MACRS.

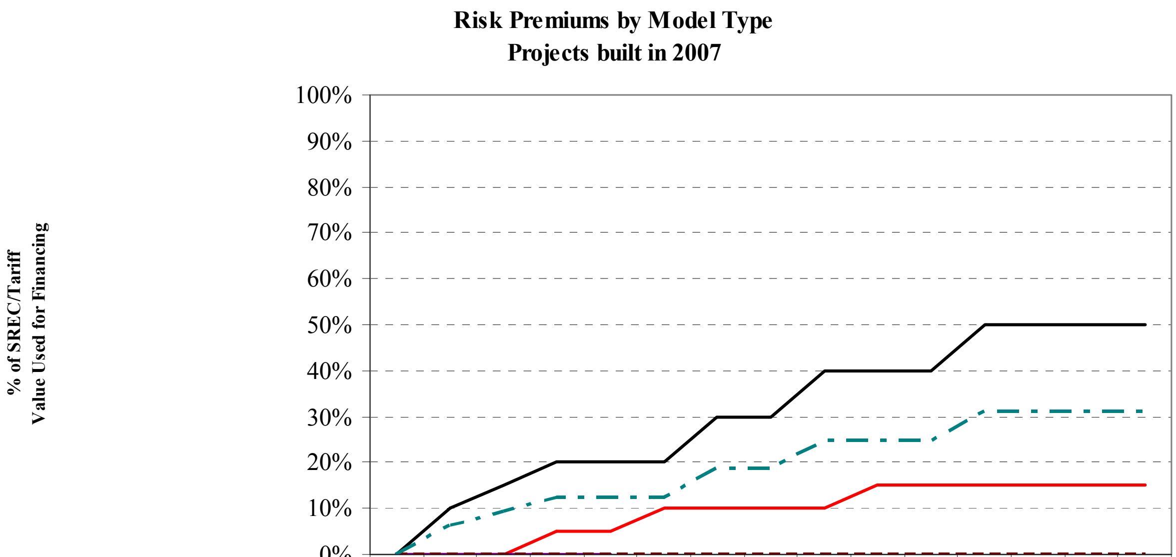
Target IRR – the project economics target IRR. Source: Based upon discussions with industry but adjusted downward to be more conservative.

2.4.3 Risk Premium Assumptions

As discussed above, each proposed scenario has a different uncertainty in the future stream of incentive payments. The 15 Year Tariff scenario has a very certain stream of incentive payments, while the SREC Only scenario has a lot of uncertainty around the value of the incentive stream. When calculating the project economics project developers will assign a high risk premium to more uncertain future incentive payments. Figure 2-8 presents the Risk Premium profiles for each of the scenarios for a project built in 2007.

[21] According to 26 USC Sec. 136 utility solar incentives for residential end-users are not considered taxable income. Utility incentives for commercial end-users used to have a limited exemption (IRS Code Sec. 136), but this was repealed in 1996.

Figure 2-8. 2007 Project Risk Premium Profile



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Base Case/SREC-Only/Commodity	0%	10%	15%	20%	20%	20%	30%	30%	40%	40%	40%	50%	50%	50%	50%
Underwriter	0%	0%	0%	5%	5%	10%	10%	10%	10%	15%	15%	15%	15%	15%	15%
Auction Model	0%	0%	0%	0%	0%										
15 Yr Tariff Model	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hybrid-Tariff Model	0%	6%	9%	13%	13%	13%	19%	19%	25%	25%	25%	31%	31%	31%	31%

Once a scenario is selected and the market has time to settle, the project developers should develop a better understanding of future incentive streams. As project developers get more experience with these future incentive streams, the risk premium assigned to these streams of incentives should also decrease.

The model is based upon the project economics of a project built in 2007. The stream of incentives needed to meet the targeted IRR for the 2007 projects is assumed to apply to projects built in years 2008-2021. This model does not take into account the expected decrease in the risk premium that developers may assign to the incentives in the more mature years of the scenario.

The difference in risk premiums assigned by the developers to the future stream of incentives in the later years of the scenario have much less impact on the RPI than the risk premiums in the early years of the program due to the time value of money and discounting. Table 2-6 shows comparison of a $1,000 incentive with a risk premium of 50% in 2008 and 2021. The present value of the 2008 incentive is significantly higher than the present value of the incentive offered in 2021. The difference between a 50% risk premium and a 25% risk premium in 2008 is $228 in 2007 dollars. The difference between a 50% risk premium and a 25% risk premium in 2021 is $66 in 2007 dollars.

Table 2-6. Risk Premium Discount Example

	Incentive Amount	Risk Premium	Adjusted Incentive	Discount Years	PV @ 10% Disc Rate
2008 Incentive	$1,000	50%	$1,500	1	$1,364
2008 Incentive	$1,000	25%	$1,250	1	$1,136
2021 Incentive	$1,000	50%	$1,500	14	$395
2021 Incentive	$1,000	25%	$1,250	14	$329

Therefore the model may overstate the risk premium for the projects built later in the maturity of the scenario; however due to discounting this should not greatly influence the RPI. As shown in the sensitivity analysis the adjustments to the risk premiums did not have a significant effect on the RPI.

2.4.4 Administrative Cost Assumptions

The experiences of other states informed the development of assumptions used for the SACP modeling effort. However, given the unique nature of market conditions in New Jersey and the proposed program structures being modeled, existing renewable energy program administrative costs were used as the reference point for developing specific assumptions regarding the administrative costs associated with the seven market models included in the modeling effort.[22]

For reference, in 2007, administrative costs equal approximately four percent of the CORE Program budget.[23] This is somewhat lower than other states where average administrative costs are in the range of seven percent of renewable energy program budgets.[24]

Key administrative cost categories considered in the estimation of administrative costs included:[25]

- **Market Manager / Incentive Program Administrator Costs**
    - Issue and process applications and incentive payments
    - Perform necessary program tracking functions
    - Conduct program outreach and respond to public inquiries
    - Overhead costs
- **OCE Oversight Costs**
    - Manage relations with Market Manager / Incentive Program Administrator

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[22] The CORE program budget represents approximately 50% of the overall Clean Energy Program budget. Therefore, 50% of OCE oversight costs were allocated to the CORE program for the purposes of establishing the rebate program baseline administrative expenses. Note that some OCE oversight costs that pertained specifically to energy efficiency were excluded. The baseline also factored in $606,000 annual expenditures for a renewable energy-related market manager, as well as $554,000 annual expenditure for SREC program administration. All values are based on the 2007 OCE budget.

[23] Based on $6,068,000 as total administrative costs for renewable energy programs (includes renewable energy-related "OCE Oversight Costs" and "Market Manager Transition Costs" from 2007 budget, as well as SREC program administrative contract), and $135,500,000 as total 2007 CORE program budget.

[24] Based on data presented in: Nigro, Ralph. "State of Delaware Sustainable Energy Utility Task Force Briefing Booklet." July, 2006. Report included data on administrative costs for renewable energy programs in Connecticut, California, New York and Vermont. Renewable energy program administrative costs for those states were eight percent, ten percent, four percent and one percent respectively. Vermont's administrative costs were excluded when calculating the average since they were much lower than the other states.

[25] The items listed under each cost category are general items assumed to fit within the cost category. Costs were only estimated for broad cost categories and not for each item listed here.

- Oversee periodic Board-authorized changes in incentive program
  - Develop / adapt policies and procedures
  - Maintain professional affiliations and oversee program evaluation
- **Legal Costs**
  - Contract development and management
  - Response to potential legal issues
- **Infrastructure Costs** (over and above existing SREC system costs)
  - Contractor, hardware and/or other expenses related to developing, facilitating, and tracking incentive program activity
- **REC Tracking System Costs**
  - For all incentive models, it was assumed that the existing SREC program administration expenses would continue, or that the same amount of money would be spent to provide customer service or other support associated with having solar owners participate in GATS.
- **Monitoring and Verification Costs**
  - Monitoring system performance and program expenditures
- **Electric Distribution Company (EDC) Costs** (for Tariff / Hybrid-Tariff Models)
  - Billing system adjustments to accommodate tariff payment tracking
  - Staff time to manage tariff payment functions and respond to customer inquiries
- **Underwriter Costs**
  - Costs associated with maintaining access to funds to sustain incentive program

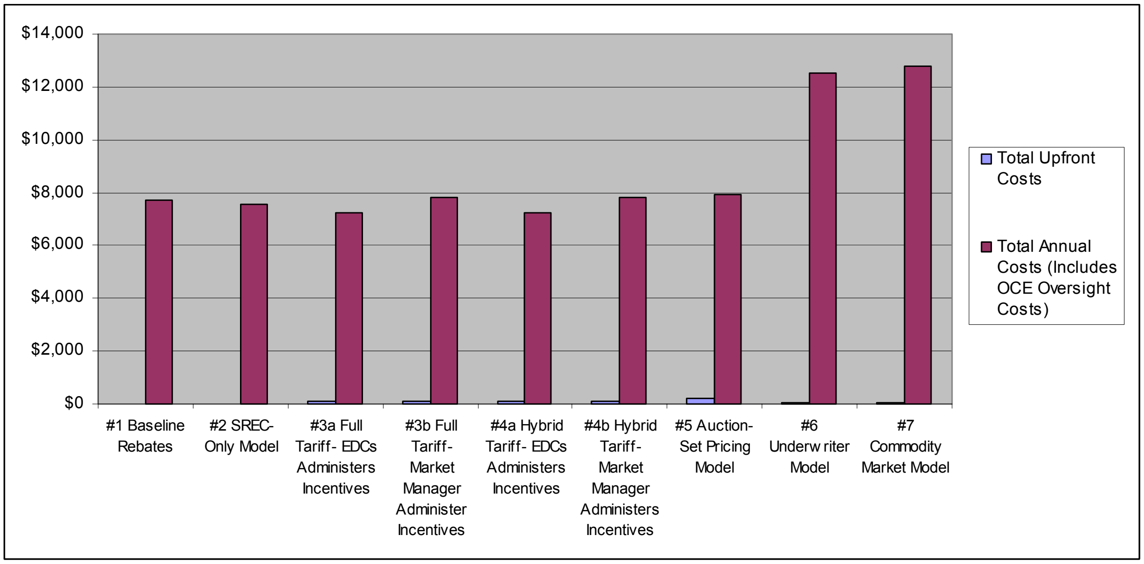
For each administrative cost category, the Summit Blue Team estimated the likely variation in costs associated with each model as compared to current baseline conditions. The values were then scaled as part of the modeling exercise according the volume of activity associated with each incentive structure that was included in the modeling effort.

For each administrative cost category listed above, the conditions associated with each incentive structure were considered. For each administrative cost category that was relevant to a particular incentive structure, the Team either: 1) applied a multiplier to existing program costs to reflect whether the incentive structure was likely to have higher or lower costs in that area relative to current program conditions; or 2) for cost categories that were unique to a particular incentive structure, the Team estimated a cost.

The administrative cost estimates are based on the Team's judgment and experience and are not precise. The goal was to establish estimates that would fall within a realistic range of likely costs associated with each potential incentive structure to represent the relative differences between structures being considered. It is important to recognize that administrative costs play a minor role in overall ratepayer impacts. Even if the estimated administrative cost estimates were to increase by a factor of two, the effects on overall ratepayer impacts would be negligible. Therefore, the practical aspects associated with administering the various incentive structures should be considered separately from the overall ratepayer impacts estimated from the modeling effort. A general qualitative review of administrative issues associated with the different incentive models was included in an earlier report. Since that report was completed, additional consideration was given to the unique issues associated with the Underwriter model, and discussion of those issues is included below.

A summary of the administrative cost estimates for each model is shown in Figure 2-9. Note that variations in administrative costs were considered for the tariff models (both hybrid and full-tariff structures) based on whether the EDCs or Market Manager / OCE were to administer the programs.

Figure 2-9. Summary of Administrative Cost Estimates (all #s '000s)



Overview of Assumptions by Cost Category

This section includes a brief discussion of variations in cost estimates by administrative cost category.

<u>Market Manager / Incentive Program Administrator Costs</u>

It was assumed that the tariff models (full-tariff and hybrid tariff models) would result in much lower market manager costs if the EDCs administer the incentive payments rather than the market manager since EDCs could take advantage of existing metering and billing system functions. However, if EDCs administer a tariff program, they would incur some costs associated with training and adapting their billing systems to facilitate the processing of tariff payments. If the market manager were to administer a tariff program the administrative costs would be higher than those associated with administering rebates since periodic payments would need to be made and regular communications kept up with participants. For this cost category, costs associated with the full and hybrid-tariff systems were assumed to be the same since the main difference would be the value of payments rather than the volume of participants.

For the auction-set pricing system, market manager costs were assumed to be the same as if the market manager were to administer a tariff program. There would be no responsibility to issue incentive payments, but the market manger would still play a significant role in overseeing and tracking the status of SREC contracts, and would be responsible for organizing and administering an annual auction.

For both the underwriter model and its variant, the commodity market model, administrative costs associated with the Environmental Infrastructure Trust Fund (EITF) were used as a proxy for many of the administrative costs associated with the underwriter function, including those of the market manager or some other program administrator. A description of the EITF and how it relates to the Underwriter model is included in the "Underwriter Costs" discussion below.

The commodity market model would include continuation of a rebate program for smaller systems. Market manager costs associated with administering those rebates are assumed to be about half that of the existing rebate program since the program would be scaled back significantly.

For the SREC-Only model, it is assumed that the market manager costs would be somewhat lower than under the current rebate program. The market manager would not process rebate payments, but would still need to review project details and process applications for participation under the program.

OCE Oversight Costs

It is assumed that OCE oversight costs would be the same regardless of the incentive structure in place. OCE will need to play a significant role in establishing the standards and procedures associated with any of the incentive models.

Legal Costs

For a tariff program, it is assumed that there would be upfront legal costs associated with establishing all necessary contracts. Ongoing legal costs of a tariff program are assumed to be the same as those associated with the baseline rebate program. For the auction-set pricing model, upfront legal costs are assumed to be about double those associated with a tariff program, and ongoing legal costs would be somewhat higher than the baseline since the role of standard contracts is central to this model. For the Underwriter and Commodity Market models, costs associated with administering the EITF are used as a proxy. Legal costs associated with the SREC-Only model are assumed to be somewhat lower than under the baseline rebate program since there would be less volume of activity and a lower level of state involvement in projects.

Infrastructure Costs

For a tariff program administered by the EDCs, infrastructure costs would be relatively low. EDCs would need to adapt their systems somewhat to accommodate tracking of solar generation and tariff payments, but this would be less expensive than if the market manager were to administer the program. If the market manager were to administer a tariff program, they would need to develop and maintain a tracking system that could accommodate the dynamic nature of the program. For the Auction-set Pricing model, a bid processing system would need to be developed, as well as a system for tracking issuance of standard contracts and compliance with contract terms. These systems would require on-going maintenance as well. For the Underwriter and Commodity Market models, start-up costs associated with developing a tracking system were included. The SREC-Only model was assumed to have ongoing infrastructure needs that would be somewhat lower than those associated with the baseline rebate program.

REC Tracking System Costs

For all incentive models, it was assumed that the existing SREC program administration expenses would continue, or that the same amount of money would be spent to provide customer service or other support associated with having solar owners participate in GATS.

Monitoring and Verification Costs

For the tariff models, it is assumed that automated metering would be incorporated into all solar projects participating in the program and that participants would absorb any costs associated with this. If the market manager were to administer the program, upfront costs are estimated for establishing a system to obtain monthly generation data. It is also assumed that ongoing monitoring and verification costs would be lower than for the baseline rebate program since actual metered production data would be available. For all other incentive models, it is assumed that monitoring and verification costs would be the same as for the baseline rebate program.

EDC Costs

If EDCs administered a tariff program, they would incur a relatively low level of administrative costs associated processing incentive payments, which would be passed along to ratepayers.

Underwriter Costs

It is challenging to estimate the costs associated with administering the underwriter function included in both the Underwriter and Commodity Market models. As proposed, the underwriter would rely on SACP / ACP payments as the primary source of funding. This does not seem like a practical approach since the SACP / ACP funds would not be a predictable or reliable source of funds and availability of these funds may not coincide with the timing of the funding needs of the program. Therefore, for the purposes of estimating the costs of administering an underwriter program, we have assumed that an underwriter would secure access to funds to support the program commitments with some associated premium. We have not characterized the specific details of such an arrangement (i.e., what entity would act as the underwriter and what arrangement would be used to secure funds) as these details would depend on factors that are outside the scope of this analysis.

As a proxy for costs associated with administering the Underwriter program, we have looked to the New Jersey Environmental Infrastructure Trust, a program that provides low-cost financing for the construction of infrastructure related to maintaining water quality.[26] The Trust provides projects with funds from a zero-interest revolving loan fund and from tax-exempt revenue bonds sold by the Trust. While the Trust functions quite differently than an underwriter would, it was deemed a suitable proxy for administrative costs given its role as a major state-based financing entity supporting infrastructure development. In 2006, the Trust's financing program supported $832 million worth of project development and total costs to administer the program were $5,375,989. Assuming an SREC floor value of $300, the maximum underwriter exposure in 2021 is estimated to be $657 million. Given that the financial support provided by the underwriter program would be much lower than that of the EIT even at its greatest level in 2021, the costs associated with the Trust are assumed to be a conservative proxy for underwriter costs.

Another program that was examined as a means of estimating the costs of administering an underwriter program was **Massachusetts' Green Power Partnership** (MGPP) administered by the Massachusetts Technology Collaborative's Renewable Energy Trust (MTC). MGPP is similar to an underwriter model in that MTC functions as a REC buyer of last resort for renewable energy projects. MTC enters long-term contracts with a select set of utility-scale projects to provide certainty about the future minimum value of RECs from the projects. Contracts can be for straight REC purchases, or for put and/or call option(s). The program has had two solicitations (2003 and 2005), and 11 projects have been funded representing $59M in nominal funding commitment.[27]

The first round of program funding came entirely from SBC funds. MTC determined the amount of funding it could commit based on the needs of the project applicants and the amount of SBC funds that could be put in escrow in the form of bonds to yield the funding commitment in the years those commitments would come due (participants could choose a future set of years to have MTC commit to). The second round of program funding was about a 50/50 split between SBC and ACP funds. ACP funds

[26] Information obtained from the New Jersey Environmental Infrastructure Trust Fund website: http://www.njeit.org/news/encap-statement.htm.

[27] Information regarding MGPP came from personal communication with the program manager, Nils Bolgen, and from information available on MTC's website: http://www.mtpc.org/renewableenergy/mgpp.htm.

had already been collected, and MTC knew how much money it was working with before making commitments.

MTC secures access to funds to support program commitments by buying “zero coupon” treasury bonds. These treasury bonds are held in escrow. Buying bonds helps MTC leverage funds. Thirty-nine million dollars in SBC funds (present value) has been used to leverage $59 million (nominal value) in ultimate funds available to pay out to project participants. MTC analysis determined that purchasing bonds and holding committed funds in escrow was the most cost-efficient method for providing the level of security necessary for project development. Since MTC uses currently available funds (either through SBC and/or ACP) and takes on the responsibility of administering the program, there are no premiums paid for gaining access to funds through a third-party entity, as is a concern related to administering an underwriter program in New Jersey.

MTC incurred approximately $675,000 in program-specific costs related to administering the first round of MGPP funding. This included the development of the RFP and contracts, selection of awardees, financial planning, and program oversight. The costs are quite low in comparison to the proxy costs assumed for a New Jersey underwriter program for modeling purposes. In New Jersey, over the period of the RPS, an underwriter program would support a much higher volume of projects and would make a much higher funding commitment than MGPP has to date. However, since MGPP is similar in nature to an underwriter program, it serves as a valuable comparison.

3. RPI MODELING RESULTS

This section presents the results of the RPI modeling analysis. The models were first run with the standard inputs for each of the project types. Then the models were re-run four times for each of the project types varying the standard inputs from 50% to 200% to determine the models' sensitivity to the input variables. The key input variables were identified and used in the Monte Carlo simulation to produce the probability distribution of the RPI.

3.1 Results with Standard Inputs

Each model was run three times for each of the three project types using the standard inputs. For each project type the incentive level that provided the targeted IRR was determined. The incentive levels were then applied to 100% of the estimated annual solar RPS generation requirements to calculate the annual solar RPS generation costs. The analysis assumes that each project type will meet 100% of the RPS requirements. The model administrative costs, up-front and annual, were added to the annual solar RPS generation costs to calculate the total annual solar RPS costs. The annual solar RPS costs were then discounted back to 2007 dollars using the discount rate. The net present value of the solar RPS costs were divided by the estimated total retail sales of electricity during the analysis period (2008-2035) to calculate the RPI in $/kWh.

Table 3-1 presents the RPI of each model by project using the standard inputs in $/kWh. Table 3-2 presents the RPI of each model by project type in millions of dollars. Table 3-2 was calculated by multiplying the results in Table 3-1 by the estimated total retail sales of electricity during the analysis period (2008-2035). The weighted average values in these two tables were calculated using the project type distribution data from the standard inputs.

Table 3-1. Ratepayer Impacts ($/kWh)

	≤10 kW Private	>10 kW Private	Public	Weighted Average
Rebate/SREC	0.00225	0.00166	0.00116	0.00181
SREC Only	0.00307	0.00183	0.00117	0.00220
Underwriter Model 15y	0.00256	0.00158	0.00100	0.00186
Commodity Market Model	0.00295	0.00183	0.00123	0.00216
Auction Model	0.00244	0.00128	0.00088	0.00167
15 Yr Tariff Model	0.00191	0.00119	0.00074	0.00139
Hybrid-Tariff Model	0.00248	0.00155	0.00096	0.00181

Table 3-2. Ratepayer Impacts ($ millions)

	≤10 kW Private	>10 kW Private	Public	Weighted Average
Rebate/SREC	$5,821	$4,291	$2,998	$4,664
SREC Only	$7,936	$4,735	$3,016	$5,691
Underwriter Model 15y	$6,611	$4,086	$2,573	$4,813
Commodity Market Model	$7,610	$4,726	$3,181	$5,589
Auction Model	$6,296	$3,298	$2,285	$4,301
15 Yr Tariff Model	$4,930	$3,079	$1,915	$3,602
Hybrid-Tariff Model	$6,403	$3,992	$2,482	$4,674

Figure 3-1 shows that the RPI of the small private projects is much higher than the RPI of both the large private and public projects. This result is due to the higher installed cost of the small private projects and the use of MACRS for the large private and public projects.

Figure 3-1. Ratepayer Impacts ($/kWh) – Standard Inputs

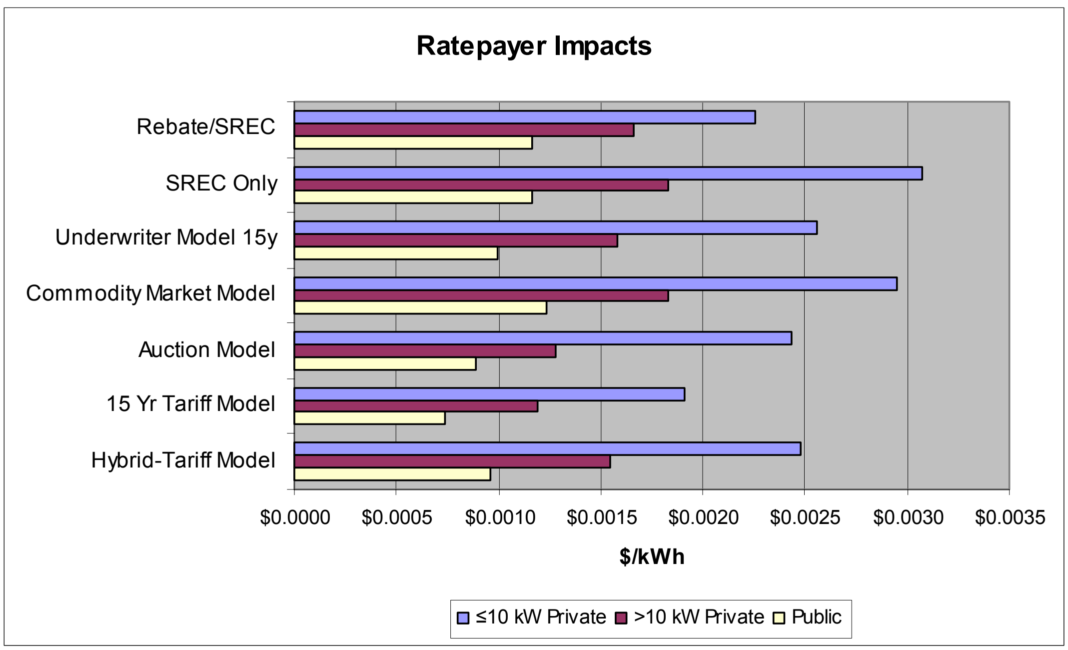


Figure 3-2 presents the weighted average RPI results. This figure shows that the 15 Year Tariff model had the lowest RPI while the SREC Only and the Commodity Market Model have the highest RPI. The 15 Year Tariff has the lowest RPI because of the low risk premium assigned by developers to the stream of incentives from the firm tariff. Conversely, the SREC Only and Commodity Market Models have high RPI because developers assign a high risk premium to the uncertain stream of incentives in these models.

Figure 3-2. Weighted Average RPI – Standard Inputs

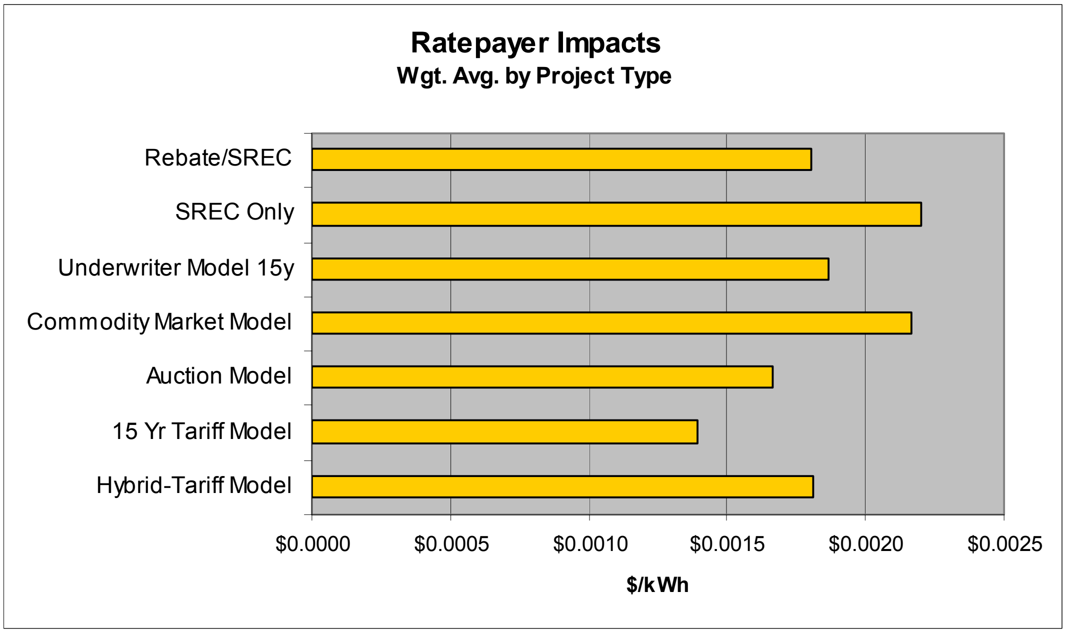


Figure 3-3 presents the weighted average RPI again with the administrative costs shown separately. As is shown on this chart the administrative costs do not significantly impact the overall RPI.

Figure 3-3. RPI Impacts Administrative Costs – Standard Inputs

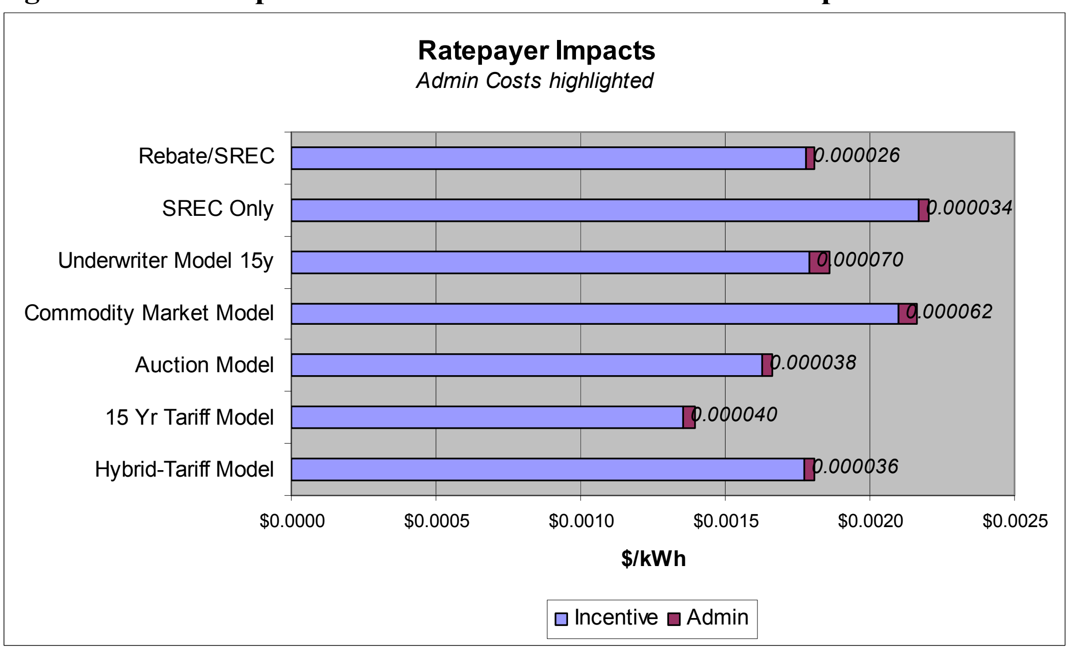


Figure 3-4, Figure 3-5 and Figure 3-6 present the annual RPI for the small private project type. These figures shows that the cost burden of the models are not distributed equally over the analysis period. Some models, e.g., Auction Model, have high costs in the early years, while the cost of other models is more distributed throughout the analysis period.

Figure 3-4. Annual RPI - ≤ 10 kW Private

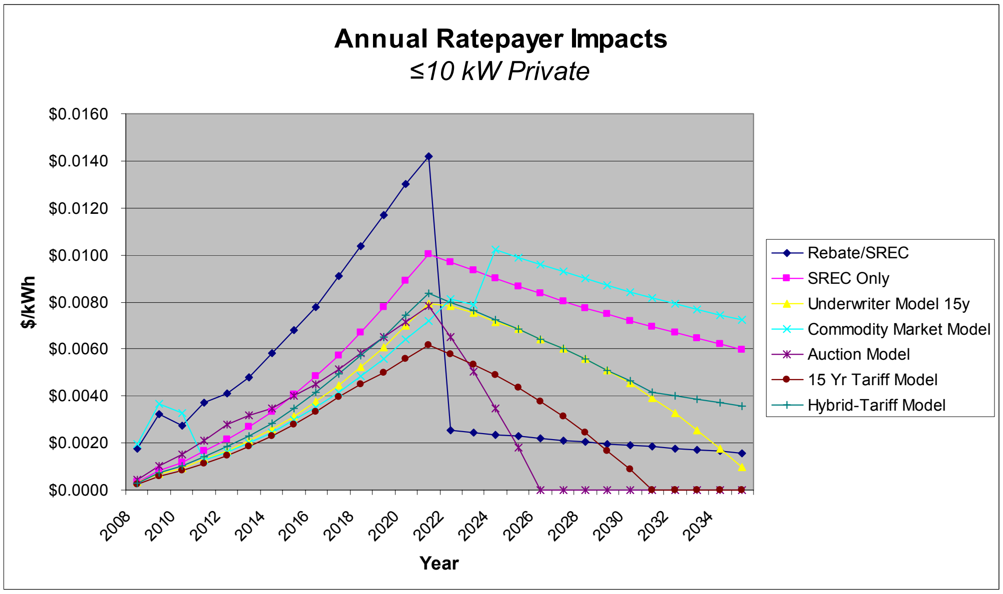


Figure 3-5. Annual RPI - > 10 kW Private

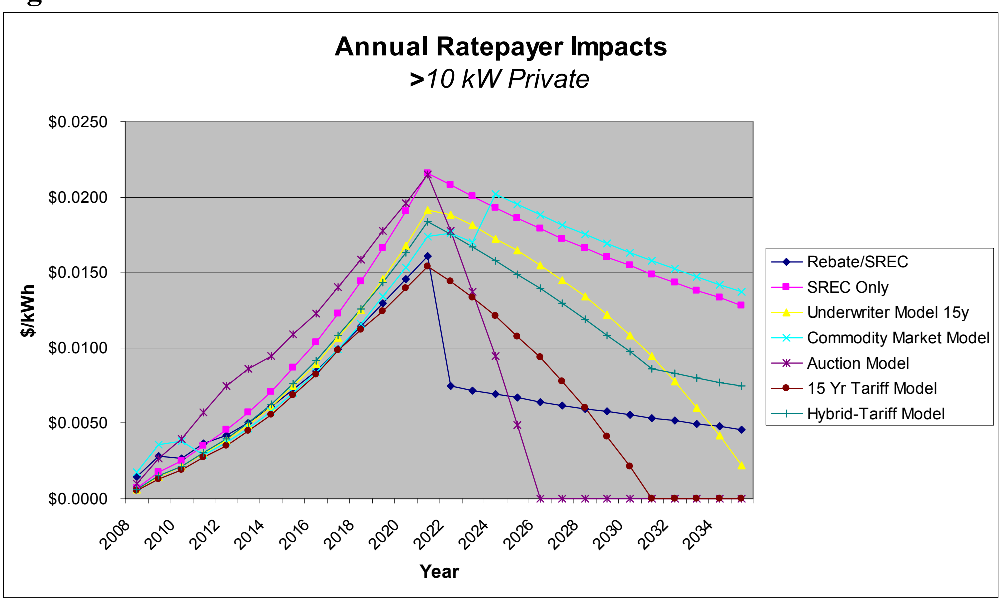


Figure 3-6. Annual RPI - Public

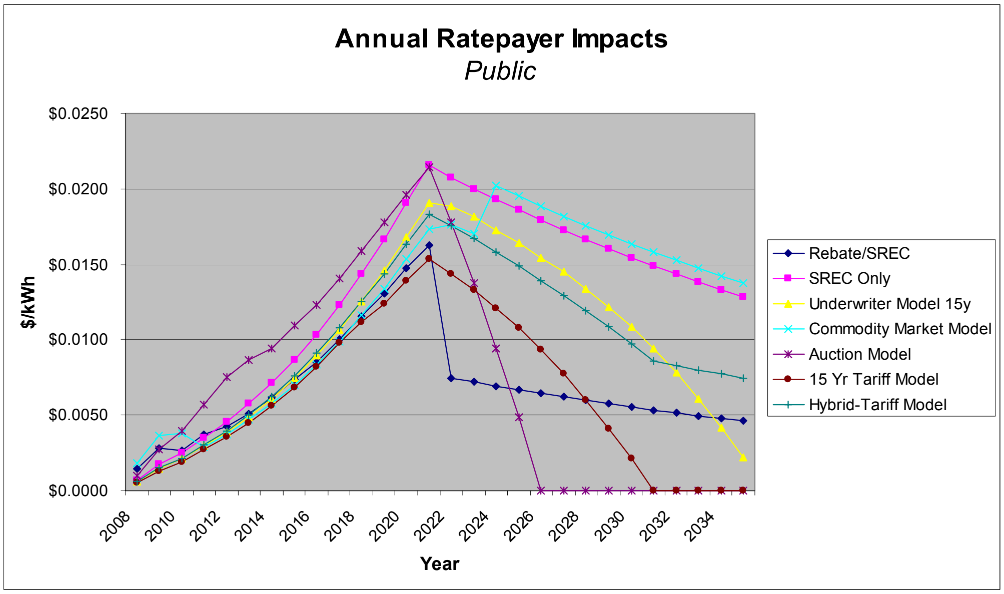


Table 3-3 presents the incentives values required to provide the targeted IRR for each scenario.

Table 3-3. 2008 Incentive ($/MWh) Value by Scenario – Standard Inputs

Scenario	Incentive Type[28]	≤10 kW Private	>10 kW Private	Public	Wgt. Avg.
Base Case	SREC	$510	$380	$139	$388
SREC Only	SREC	$1,430	$849	$537	$1,023
Underwriter Model 15y	SREC	$1,151	$705	$437	$833
Commodity Market Model	SREC	$1,151	$705	$437	$833
Auction Model	SREC	$2,216	$1,152	$792	$1,508
15 Yr Tariff Model (Tariff)	Tariff	$1,067	$662	$407	$776
Hybrid-Tariff Model (SREC)	SREC	$815	$505	$311	$593

3.2 Sensitivity Analysis

The values of the primary standard inputs were varied to determine which inputs have a significant influence on the RPI value. The primary standard inputs that were included in the sensitivity analysis were:

- Discount Rate
- Project Type IRR Targets
- Financial Risk Premium of the Incentives
- Annual Generation of the Installed PV System
- Installed Cost of the PV System

[28] 1 SREC = 1 MWh

- Annual Change in Installed PV System Cost
- Electric Sales Annual Growth Rate
- Annual Change in Electric Rates

The following set of charts show the sensitivity of the RPI to the primary standard inputs. The standard inputs were varied from 50% of the standard value to 200% of the standard value. The inputs that have a strong influence on the RPI are:

- Discount rate (Figure 3-7)
- Project type IRR (Figure 3-8)
- Annual Generation of the PV System (Figure 3-10)
- Installed Cost of the PV System (Figure 3-11)

Figure 3-7. Sensitivity Analysis – Discount Rate

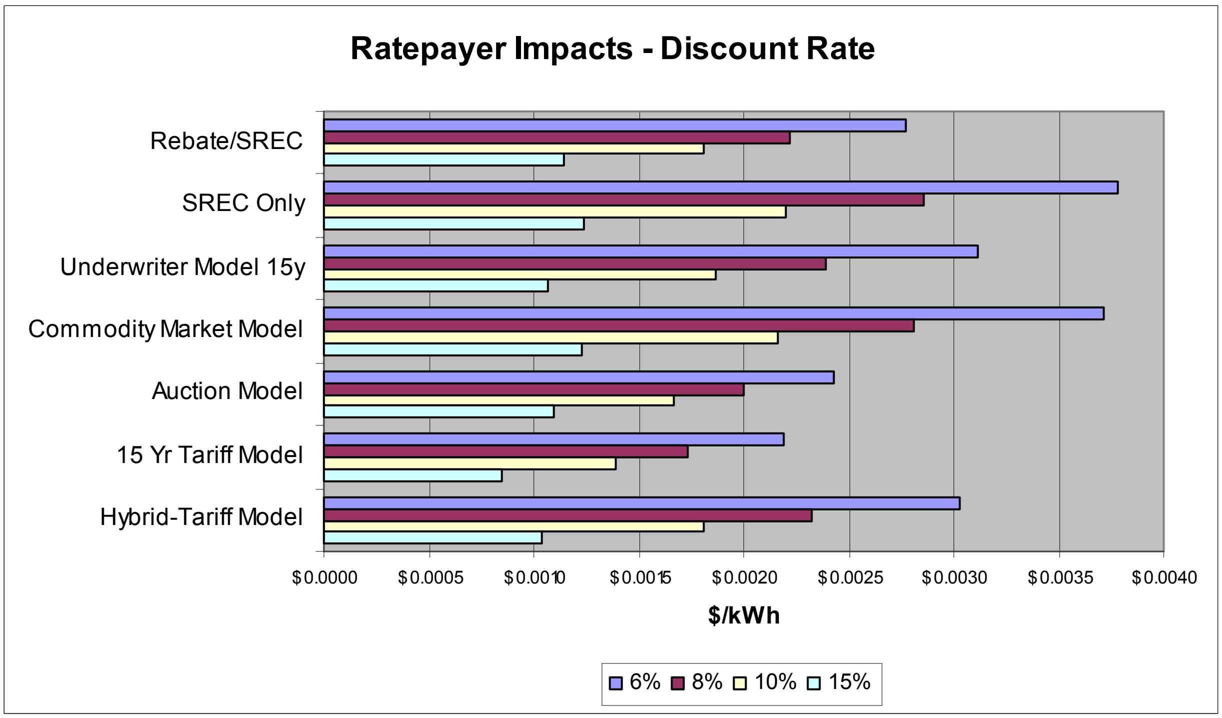


Figure 3-8. Sensitivity Analysis – Project IRR Targets

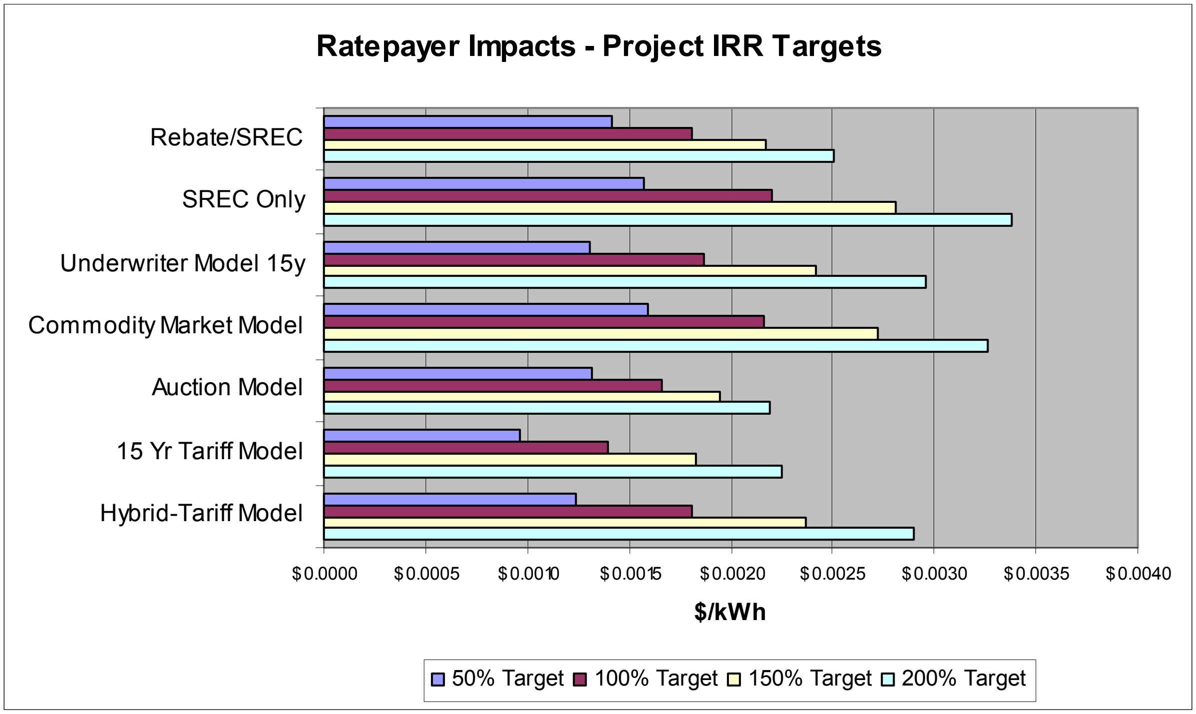


Figure 3-9. Sensitivity Analysis – Incentive Risk Premium

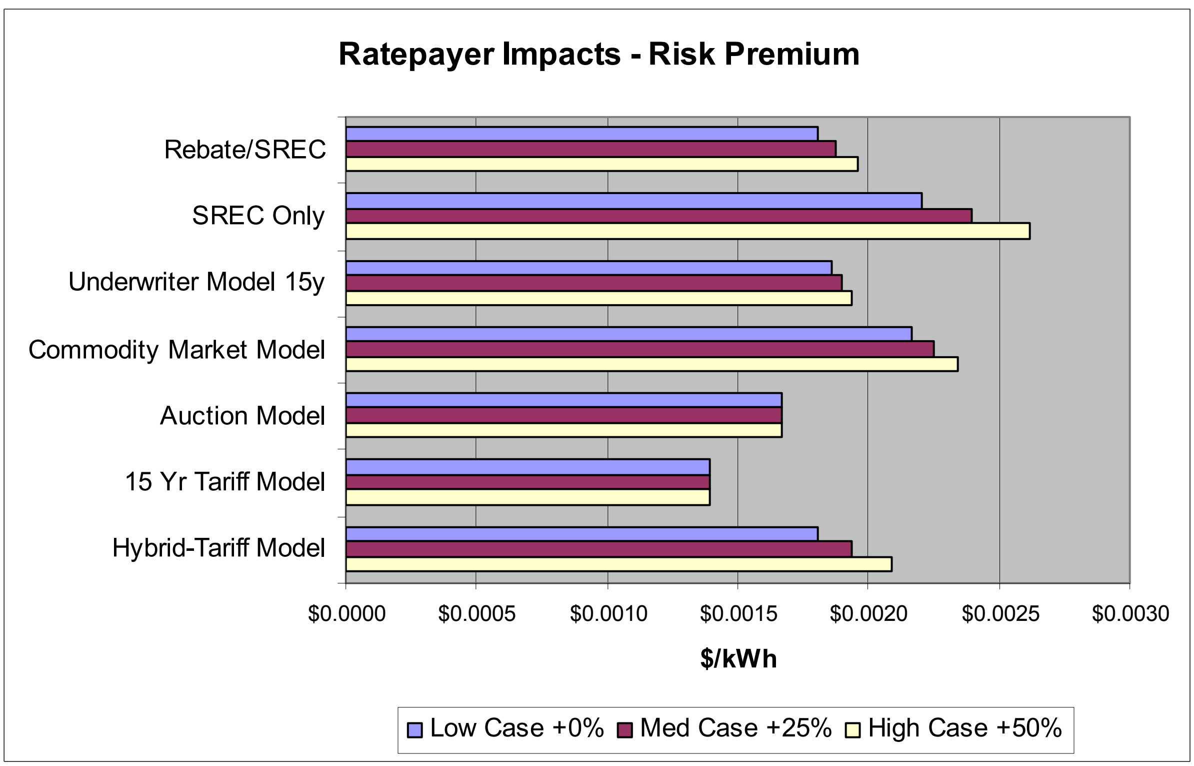


Figure 3-10. Sensitivity Analysis – Annual Generation of Installed System

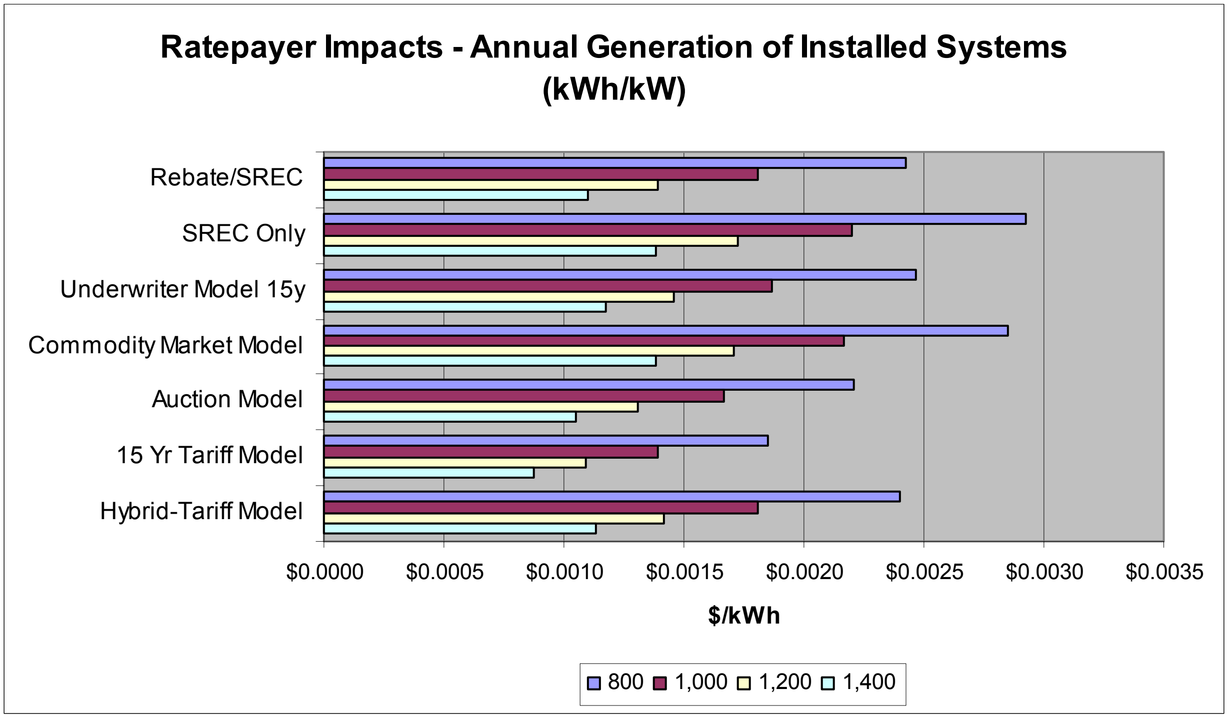


Figure 3-11. Sensitivity Analysis – Installed Costs of PV System

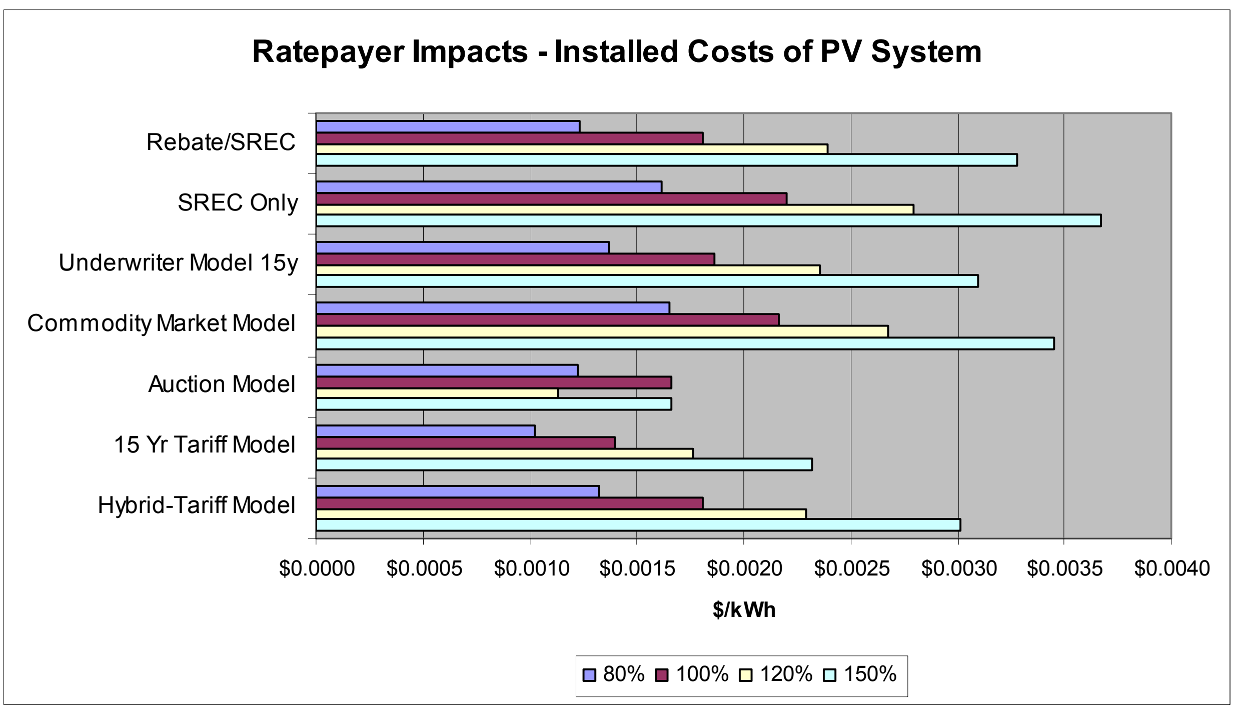


Figure 3-12. Sensitivity Analysis – Annual Change in System Costs

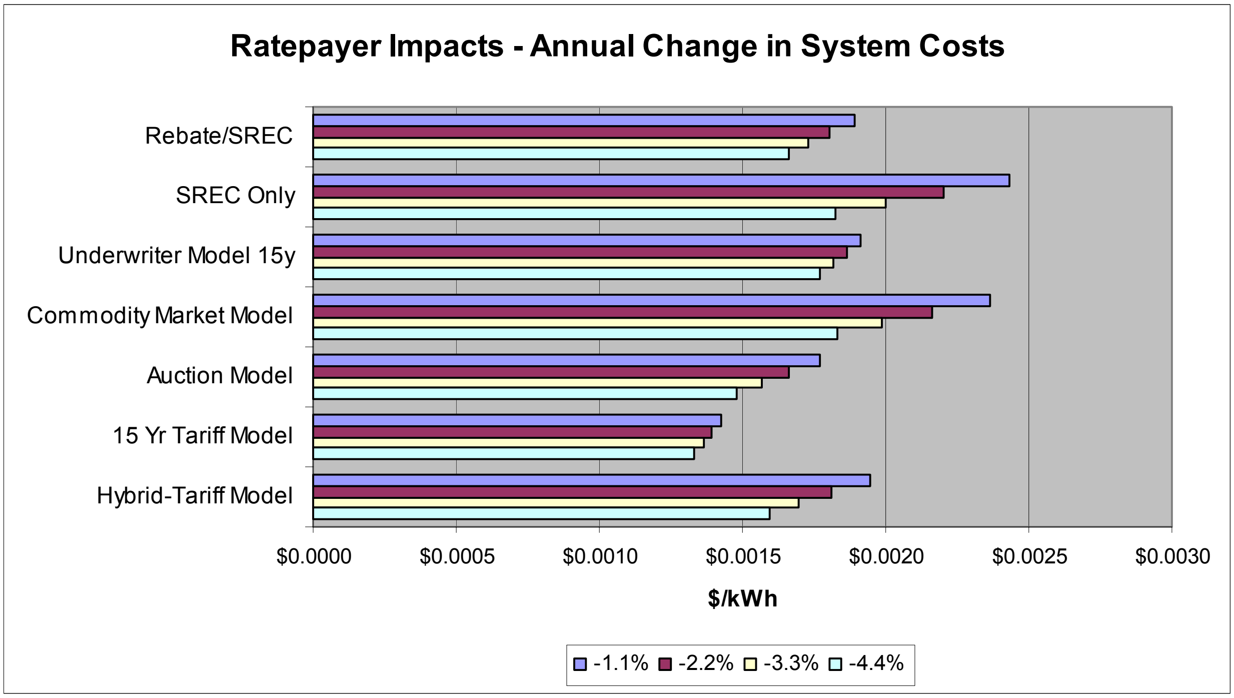


Figure 3-13. Sensitivity Analysis – Electric Sales Growth Rate

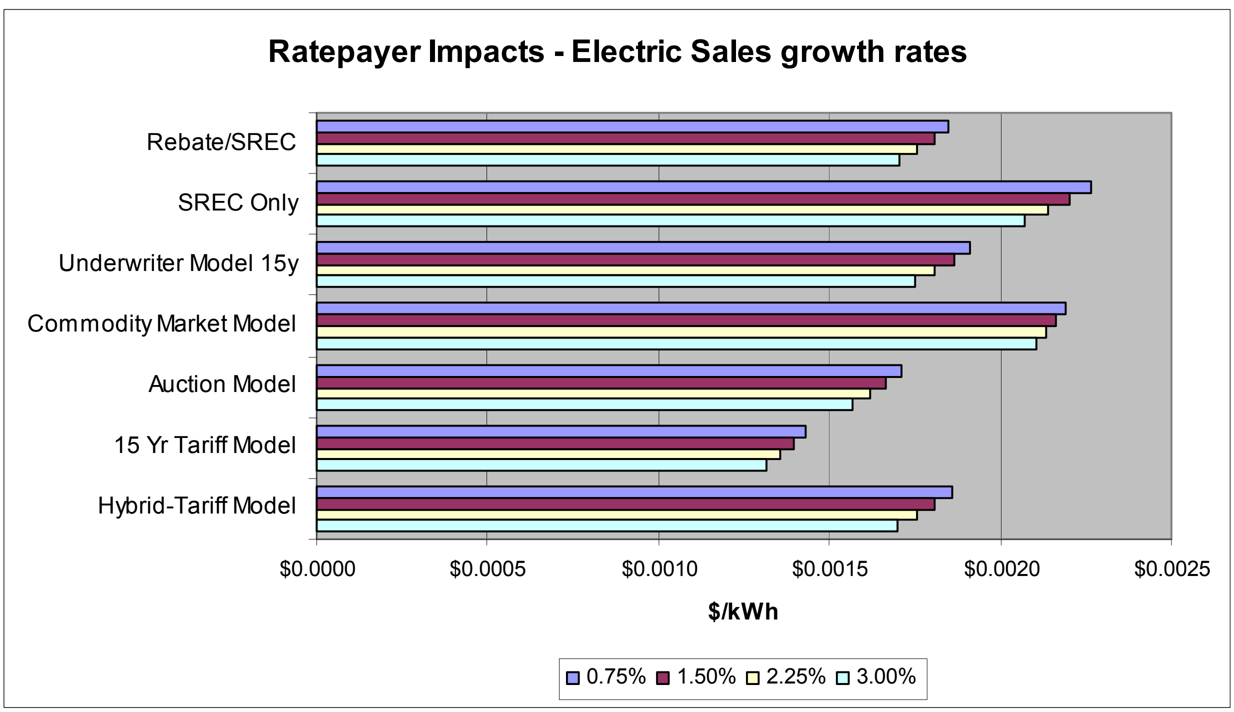
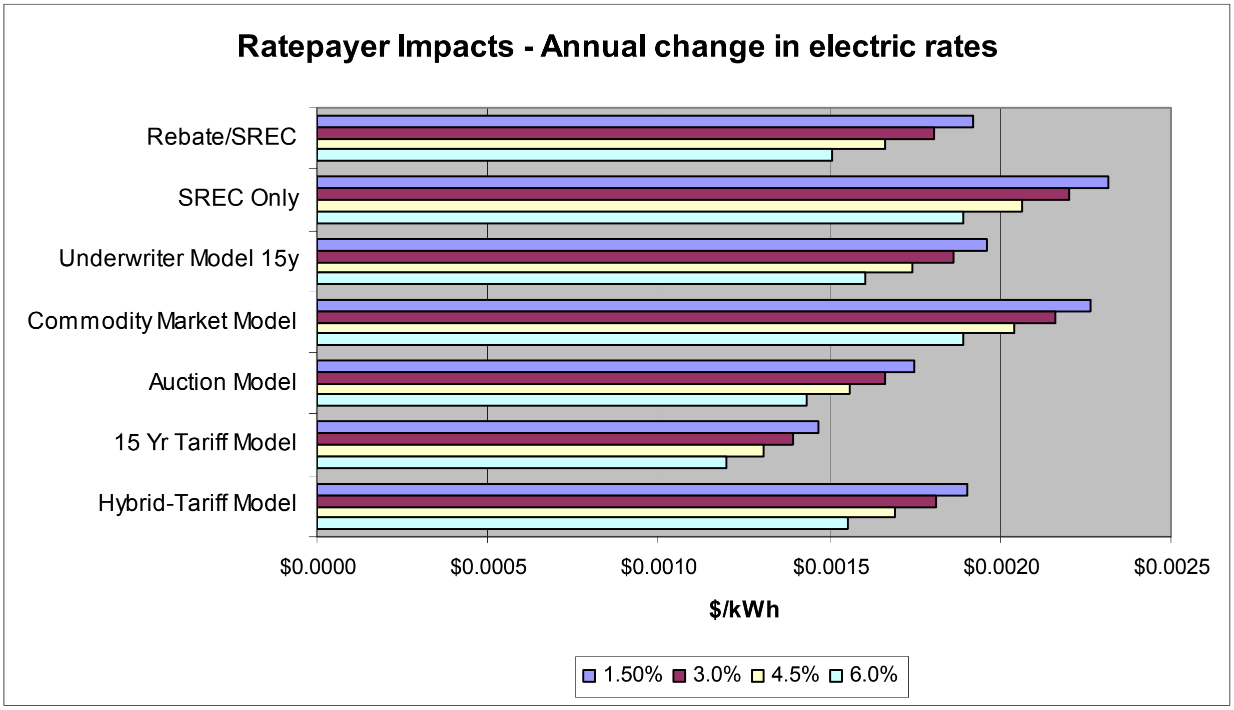


Figure 3-14. Sensitivity Analysis – Annual Change in Electric Rates



3.3 Monte Carlo Analysis and Results

An Excel spreadsheet model can only calculate one outcome at a time, generally the most likely or average scenario. Spreadsheet risk analysis uses both a spreadsheet model and simulation to automatically analyze the effect of varying inputs on outputs of the modeled system. A common method used in spreadsheet simulation is a Monte Carlo simulation, which randomly generates values for uncertain inputs over and over to simulate a model.

For each uncertain variable in a simulation, all the possible values are defined using a probability distribution. The distribution shows each of the possible values and the probability of that value occurring. A simulation calculates numerous scenarios of a model by repeatedly picking values from the probability distribution for the uncertain variables and running the calculations using those values. Examples of probability distributions include normal distributions, triangle distributions, uniform distributions, and lognormal distributions.

The results of each calculation in a Monte Carlo simulation are captured and probability distributions of the results are compiled. In this analysis the result is a probability distribution of the expected RPI. The probability distribution for each RPI results can be described by its mean value and standard deviation.

3.3.1 <u>Monte Carlo Inputs</u>

As discussed in Section 3.2, the key variables to the RPI calculation were determined. For each of these key variables, a probability distribution was developed. The sources of these probability distributions were industry experience and the available data. If enough data was available for the inputs, then a probability distribution was selected that best fit the data.

The discount rate is expected to vary from 6% to about 12% with the mean value around 10%. Most mature companies, i.e., companies not in early stages of development, use a discount factor of between 10% and 15%. The triangular distribution was the best fit for simulating the discount rate. Figure 3-15 presents the discount rate probability distribution.

Figure 3-15. Discount Rate Probability Distribution

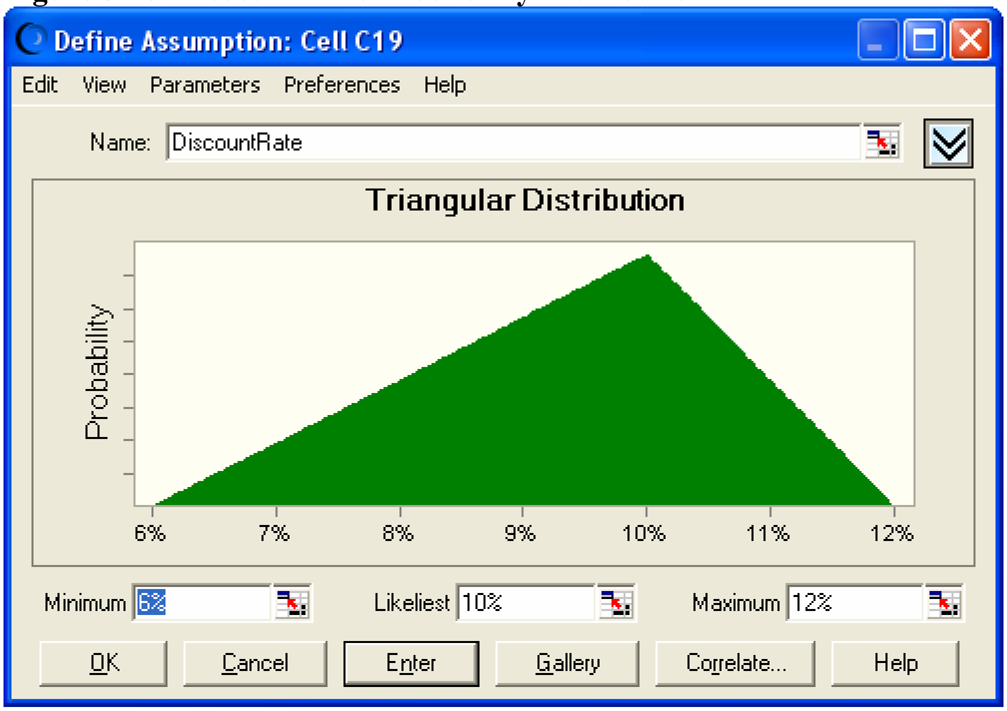


Figure 3-16 presents the probability distribution for the annual PV system electric generation. Current developers estimate that the average system in New Jersey annually produces 1,000 kWh/kW. The annual system generation will vary by installation and location. Based upon experience with PV system generation and the feedback from industry, a normal distribution with a mean of 1,000 kWh/kW and a standard deviation of 100 kWh/kW was chosen for this input.

Figure 3-16. Electric Generation Probability Distribution

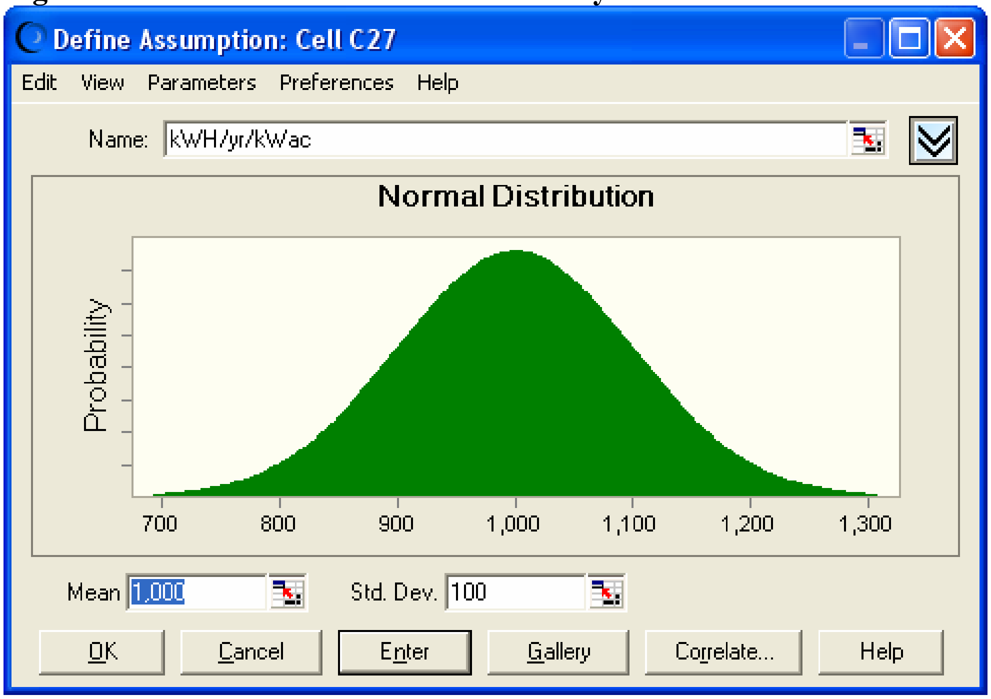


Figure 3-17, Figure 3-18, and Figure 3-19 present the probability distribution for the installed cost of the PV system for each of the project types. PV system costs per kW will vary by installation and location. An analysis of the CORE data indicated that a normal distribution best fit the data. The average system costs from the CORE database were used for the mean value and a standard deviation of 10% was assumed.

Figure 3-17. Installation Costs ($/kW) Probability Distribution - ≤ 10 kW Private Projects

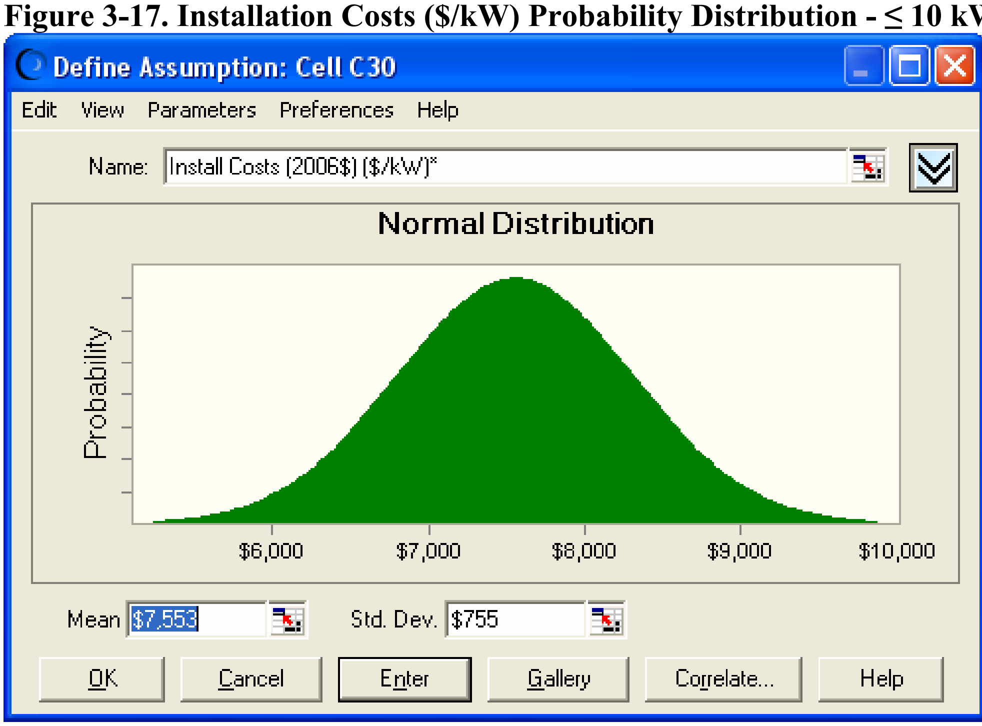


Figure 3-18. Installation Costs ($/kW) Probability Distribution - >10 kW Private

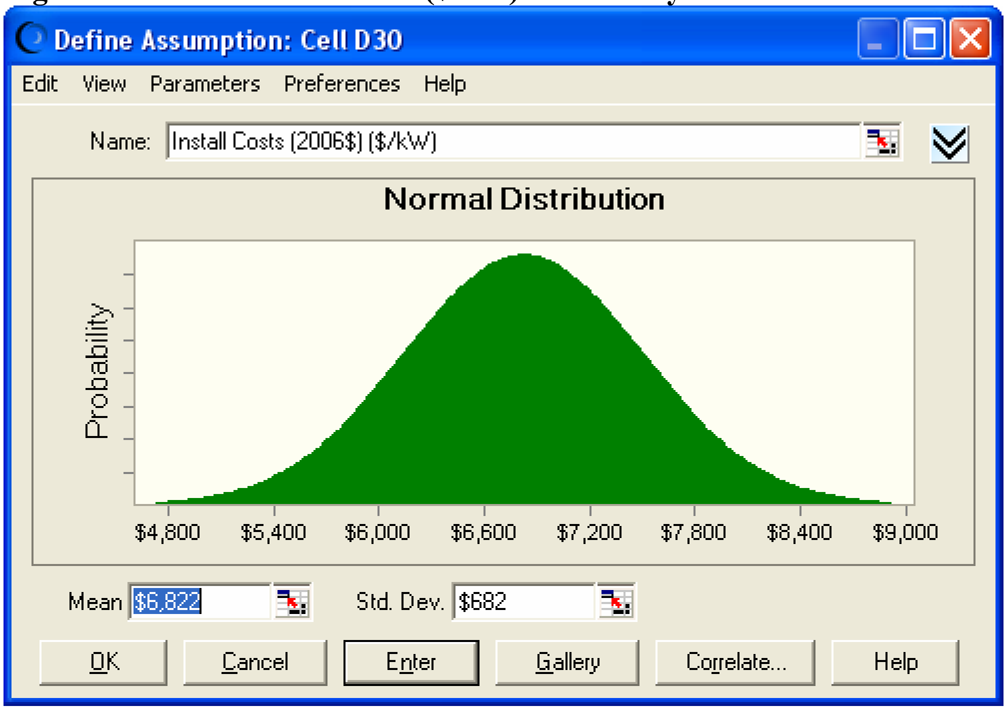
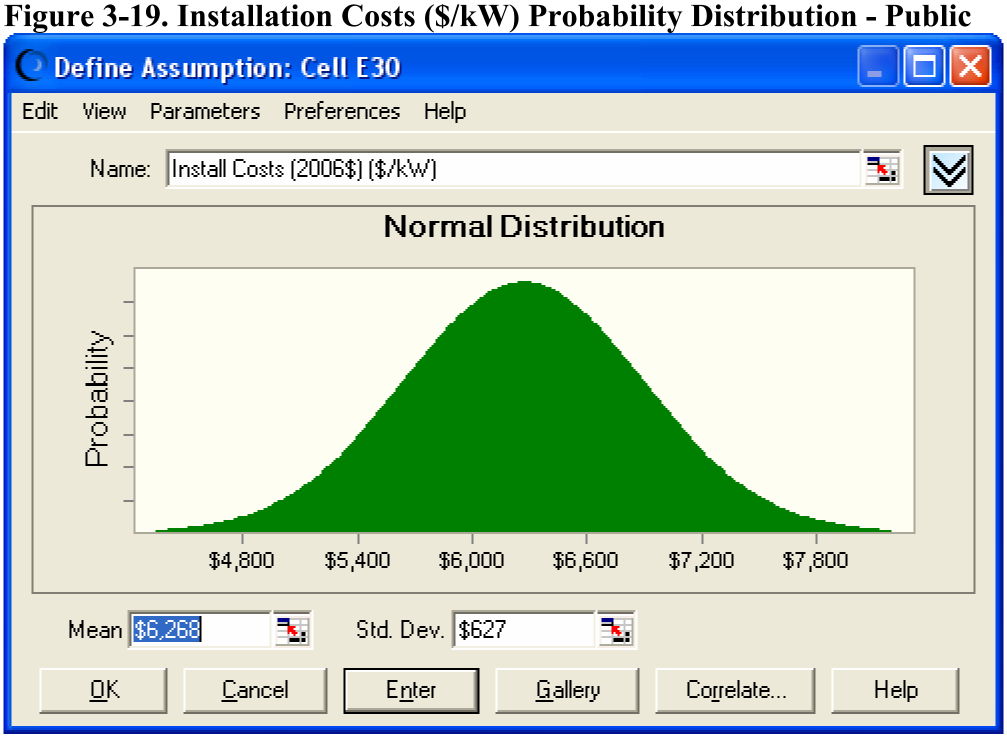


Figure 3-19. Installation Costs ($/kW) Probability Distribution - Public



The targeted IRR is the input variable with the most uncertainty. Each customer and project owner will have their own hurdle rate or cost of capital that will need to be achieved for the project to get built. Based on surveys of the project developers and industry experts, expected ranges of IRR were developed. Since these targeted IRRs are highly uncertain, a uniform distribution was selected so that each of the targeted IRR has the same probability of occurring. Figure 3-20, Figure 3-21 and Figure 3-22 present the probability distribution for each of the project types.

Figure 3-20. Targeted IRR Probability Distribution - ≤ 10 kW Private

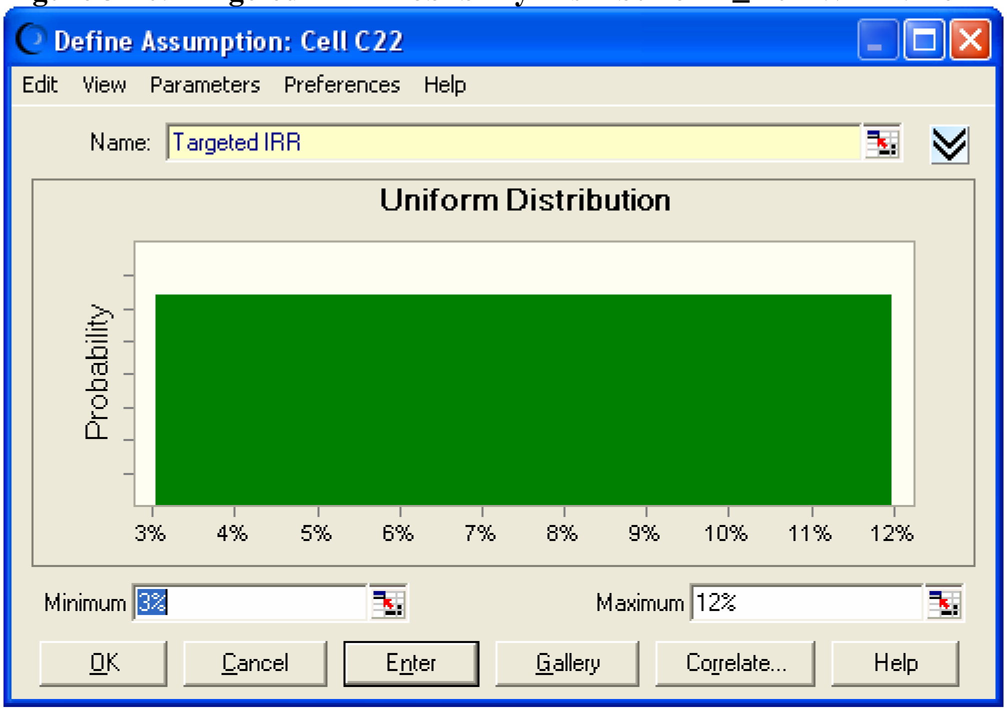


Figure 3-21. Targeted IRR Probability Distribution - >10 kW Private

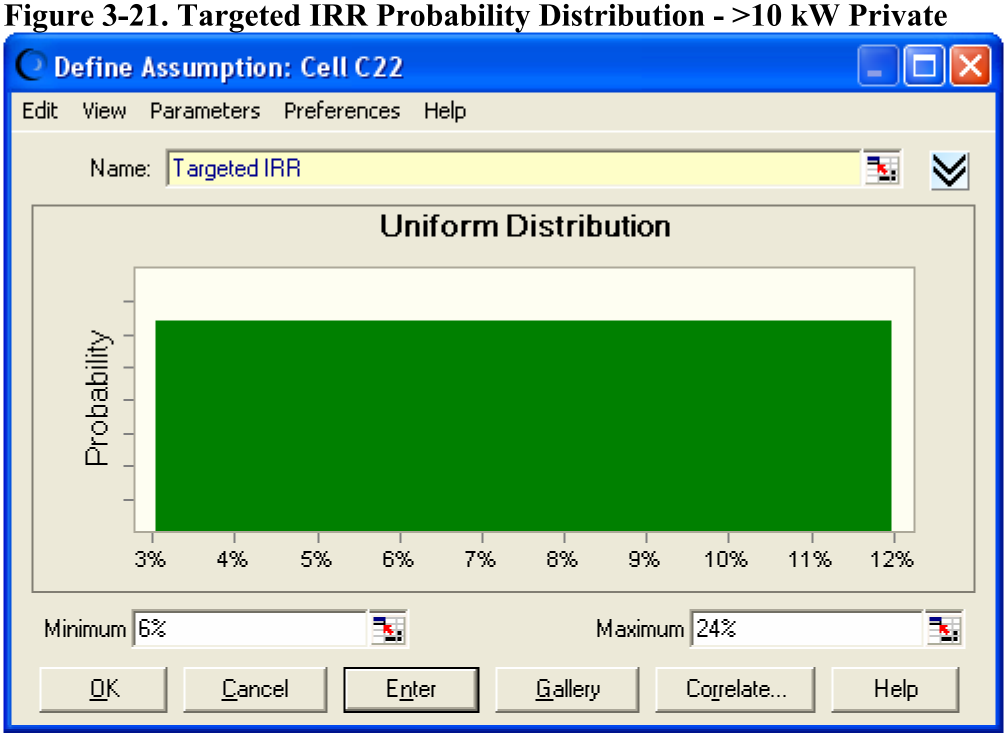
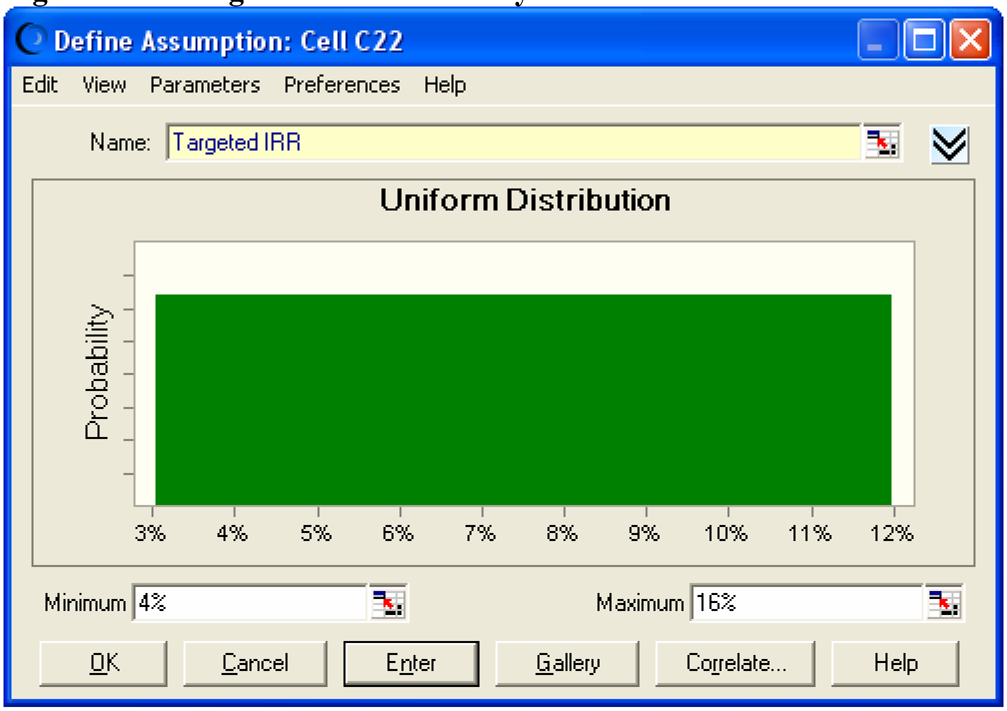


Figure 3-22. Targeted IRR Probability Distribution - Public



3.3.2 Monte Carlo Results

One thousand different sets of inputs were randomly selected from the input distributions and the RPIs were calculated for each set of inputs. The result was a probability distribution showing the expected value of the RPI. This simulation was performed for all 7 proposed models and for each project type. Figure 3-23 shows an example of the RPI probability distribution. The mean and standard deviation was calculated for each distribution. Each RPI probability distribution is presented in Appendix B.

Figure 3-23. Example RPI Probability Distribution

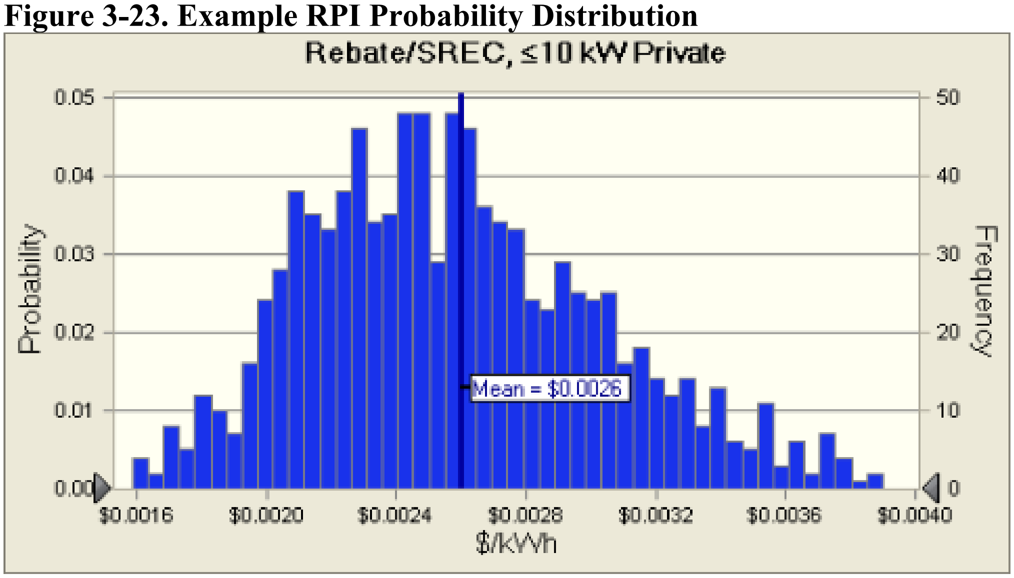


Table 3-4 presents the results of the Monte Carlo simulation ranked by lowest RPI proposed scenario by project type. The lowest RPI for all project types was the 15 Year Tariff Model.

Table 3-4. Scenario Rankings by RPI by Project Types

		$/kWh		Total $ (millions)	
Project Type	**Scenario**	**Mean**	**StdDev**	**Mean**	**StdDev**
≤10 kW Private	15 Yr Tariff Model	0.00229	0.00049	$5,910	$1,266
	Rebate/SREC	0.00260	0.00048	$6,710	$1,243
	Auction Model	0.00272	0.00040	$7,019	$1,022
	Hybrid-Tariff Model	0.00302	0.00062	$7,793	$1,599
	Underwriter Model 15y	0.00308	0.00071	$7,952	$1,822
	Commodity Market Model	0.00353	0.00070	$9,123	$1,820
	SREC Only	0.00369	0.00083	$9,533	$2,137
>10 kW Private	15 Yr Tariff Model	0.00130	0.00037	$3,363	$953
	Auction Model	0.00133	0.00028	$3,445	$715
	Hybrid-Tariff Model	0.00169	0.00043	$4,371	$1,108
	Underwriter Model 15y	0.00174	0.00051	$4,501	$1,319
	Rebate/SREC	0.00179	0.00040	$4,633	$1,027
	SREC Only	0.00202	0.00059	$5,208	$1,526
	Commodity Market Model	0.00202	0.00047	$5,224	$1,208
Public	15 Yr Tariff Model	0.00098	0.00033	$2,527	$848
	Auction Model	0.00102	0.00027	$2,641	$686
	Hybrid-Tariff Model	0.00127	0.00037	$3,288	$957
	Underwriter Model 15y	0.00132	0.00047	$3,421	$1,218
	Commodity Market Model	0.00138	0.00039	$3,569	$998
	Rebate/SREC	0.00142	0.00034	$3,679	$873
	SREC Only	0.00152	0.00051	$3,930	$1,323

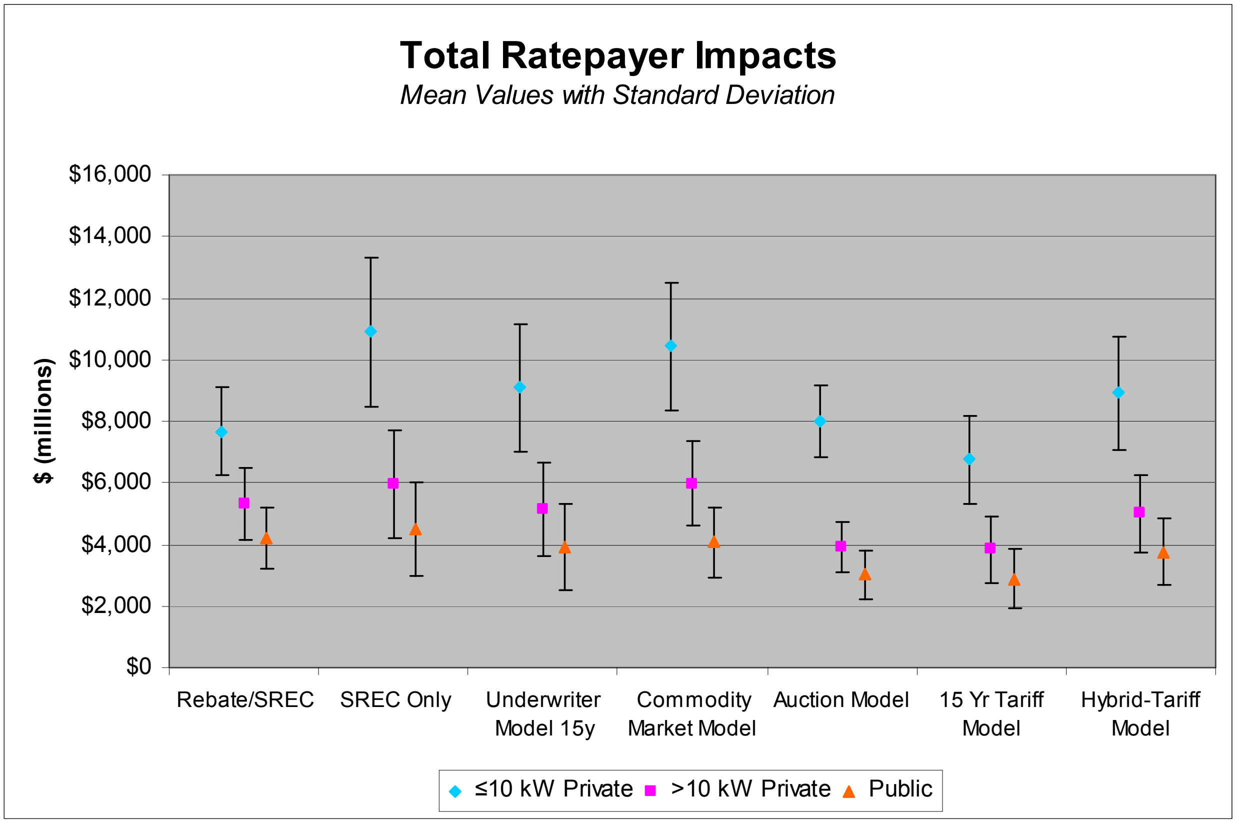
Table 3-5 presents the overall ranking of the proposed scenario and project type combinations. The public project and 15 Year Tariff scenario had the overall lowest RPI with a total projected mean impact of $2.5 billion. The low RPI for this scenario and project type is a result of the low installation costs and the low risk associated with the 15 Year Tariff scenario.

Table 3-5. Overall Ranking by RPI

		$/kWh		Total $ (millions)	
Project Type	**Scenario**	**Mean**	**StdDev**	**Mean**	**StdDev**
Public	15 Yr Tariff Model	0.00098	0.00033	$2,527	$848
Public	Auction Model	0.00102	0.00027	$2,641	$686
Public	Hybrid-Tariff Model	0.00127	0.00037	$3,288	$957
>10 kW Private	15 Yr Tariff Model	0.00130	0.00037	$3,363	$953
Public	Underwriter Model 15y	0.00132	0.00047	$3,421	$1,218
>10 kW Private	Auction Model	0.00133	0.00028	$3,445	$715
Public	Commodity Market Model	0.00138	0.00039	$3,569	$998
Public	Rebate/SREC	0.00142	0.00034	$3,679	$873
Public	SREC Only	0.00152	0.00051	$3,930	$1,323
>10 kW Private	Hybrid-Tariff Model	0.00169	0.00043	$4,371	$1,108
>10 kW Private	Underwriter Model 15y	0.00174	0.00051	$4,501	$1,319
>10 kW Private	Rebate/SREC	0.00179	0.00040	$4,633	$1,027
>10 kW Private	SREC Only	0.00202	0.00059	$5,208	$1,526
>10 kW Private	Commodity Market Model	0.00202	0.00047	$5,224	$1,208
≤10 kW Private	15 Yr Tariff Model	0.00229	0.00049	$5,910	$1,266
≤10 kW Private	Rebate/SREC	0.00260	0.00048	$6,710	$1,243
≤10 kW Private	Auction Model	0.00272	0.00040	$7,019	$1,022
≤10 kW Private	Hybrid-Tariff Model	0.00302	0.00062	$7,793	$1,599
≤10 kW Private	Underwriter Model 15y	0.00308	0.00071	$7,952	$1,822
≤10 kW Private	Commodity Market Model	0.00353	0.00070	$9,123	$1,820
≤10 kW Private	SREC Only	0.00369	0.00083	$9,533	$2,137

Figure 3-24 shows the relative RPI and uncertainty of each of the proposed model by project type. The SREC Only, Underwriter and Commodity Market Models all have the high relative uncertainties compared to the other models. In particular the smaller private projects have the highest uncertainty in these models.

Figure 3-24. Total Ratepayer Impacts – Mean and Standard Deviation ($ million)



Appendix B includes the RPI probability distributions by proposed model and project type.

3.4 Current Offer Estimated Ratepayer Impacts

The same RPI analysis method was applied to the existing CORE program offering, i.e. the current rebate structure plus the SRECs capped by the current SACP level of $300. This data is provided for reference only since the current incentive level results in different project IRR than the above analysis.

The current offering was stretched through 2021 by making similar assumptions to the scenarios above. It is expected that PV installed costs will also decrease at 1.4% annually. Therefore the rebate levels were set to decline at 1.4% annually. The SREC values were not allowed to float above the SACP and the SACP also declined at 1.4% annually.

Table 3-6 shows the RPI of the current offering through 2035 for each of the 3 project types.

Table 3-6. Current Offering RPI

	IRR	Payback	$/kWh	Total ($ millions)
≤10 kW Private	3%	14	0.001806	$4,664
>10 kW Private	10%	7	0.001490	$3,848
Public	17%	5	0.001505	$3,886

4. RPS RATEPAYER IMPACTS BENCHMARKING

The Summit Blue Team reviewed ratepayer impacts to date resulting from renewable energy initiatives in other states with RPS policies in place. While 23 states and the District of Columbia have adopted some form of RPS policy, very few of these states have had any real experience in the compliance phase. In addition, only a limited amount of data is publicly available regarding historic and long-term contract pricing for renewable energy supply. These data limitations make it difficult to arrive at any broad conclusions. However, the data that do exist provide some early evidence of the policy and market conditions most likely to result in lower RPS compliance costs.

4.1 Factors Affecting RPS Compliance Costs

RPS ratepayer impacts are affected by a number of factors rooted in policy design, renewable energy resource availability, and market conditions that exist in each state.[29] Key factors include:

- Ability of renewable energy generators to enter into long-term contracts for the sale of renewable supply (REC-only and/or bundled energy and REC contracts), and/or the presence of some other pricing certainty mechanism.
- Presence of a cap on compliance costs, which may take the form of an Alternative Compliance Payment (ACP) mechanism (as in states like New Jersey, Rhode Island, Massachusetts and others), a spending limitation (as in New York and California where RPS costs are limited by SBC funding levels), a limit on the percentage by which RPS costs can increase consumer electric bills (as in Colorado where there is a 1% cap on RPS-related bill increases), or some other cost threshold (as in New Mexico where RPS impacts must not exceed a “reasonable cost threshold” which has been interpreted differently for each eligible technology).[30]
- Existence of specific resource “set-asides,” such as the solar requirements in New Jersey, Nevada, and Colorado.
- Renewable energy siting and permitting challenges.
- Geographic restrictions on resource eligibility.
- Temporal flexibility for compliance (i.e., banking provisions and REC lifetime).

While capping compliance costs clearly limits RPS ratepayer impacts by establishing an upper boundary, the other factors listed above arguably play a more important role in actually determining the ultimate cost of RPS compliance. Given the critical nature of price certainty in the process of financing large-scale renewable energy projects, one of the strongest elements associated with low RPS compliance costs is the ability for renewable energy generators to enter into long-term contracts. Since this factor plays a defining role in determining the pace of renewable energy project development, and therefore, RPS compliance costs, it warrants further discussion.

States which lack elements to facilitate long-term contracting end up relying on more volatile short-term market pricing. When combined with project development delays and resulting early-phase supply

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[29] Wiser, Ryan, Kevin Porter and Robert Grace. “Evaluating Experience with Renewables Portfolio Standards in the United States.” Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

[30] California Public Utilities Commission. “Renewable Energy Certificates and the California Renewable Energy Portfolio Standard Program.” Staff White Paper. April, 2006.

shortages, as in Massachusetts, this drives compliance costs up to the cap.[31] Many other states with competitive electricity markets are also faced with challenges in the area of long-term contracting. In many cases, customer transition to competitive suppliers has moved slowly and competitive suppliers lack enough certainty about future demand to enter into long-term contracts with renewable energy generators.

Some states have taken steps to help facilitate the use of long-term contracts. Examples of competitive markets that have done so include Massachusetts, through its Massachusetts Green Power Partnership Program, and Connecticut, through its Project 100 which requires utilities to enter into >10 year contracts for at least 100 MW of supply. In some states, such as Nevada, where utilities are actually *required* to enter into long-term contracts, a lack of utility creditworthiness has limited the execution of long-term contracts.[32]

As evidenced by the fact that numerous Texas wind projects that have been financed through low-price, long-term contracts (Table 4-1), it is clear that long-term contracting, coupled with ample resource availability and limited siting issues, are a recipe for low-cost RPS compliance. On the other end of the spectrum, Massachusetts has demonstrated that a lack of long-term contracting, coupled with siting difficulties, can cause RPS cost impacts to reach their maximum limits while slowing progress toward the policy's goal to trigger the development of renewable energy generating capacity. Clearly, issues such as resource availability and siting constraints are beyond the control of state entities responsible for designing and implementing RPS policies, and RPS policies can still be successful despite early challenges.

Another important compliance cost factor worthy of further discussion is the setting of ACP levels. In states relying on ACPs as a compliance cost cap, the levels set will function as a price ceiling and will potentially have a substantial impact on the market pricing of RECs. The levels set must reflect the goal of limiting ratepayer impacts if a supply shortage occurs. However, in order to limit the ACP's influence on market pricing in market conditions where supply and demand are relatively in balance, it is important to set the level high enough above expected compliance costs that entities with RPS obligations have a strong incentive to become active market participants and to truly consider the ACP a last-resort option for compliance. By keeping the ACP / SACP far enough above the levels needed to make projects economically viable, RPS compliance costs will be more a function of actual project development costs and less a function of ACP/SACP level. Policy experts have recommended setting ACP levels that are at least double the level that coincides with expected compliance costs.[33]

Of course, a variety of other mechanisms exist for capping RPS compliance costs. For reference the summaries of cost cap mechanisms in place in other states are included in Appendix C. While these other strategies avoid the balancing act of setting an appropriate ACP level, they each come with their own administrative and technical challenges.

The long-term contracting issue is of great relevance to New Jersey. Since BGS suppliers operate on a three-year contract cycle, there is little incentive to enter into contracts with terms substantially longer than three years. This situation has been a key driver behind the solar industry's intense focus on

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[31] Long-term contracting difficulties in Massachusetts are partly to blame for this initial shortage of supply, but siting challenges have been one of the biggest factors contributing to the slow pace of renewables development in New England.

[32] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

[33] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004; Hamrin, Jan, personal communication, 12/1/06.

identifying a practical financial incentive option that will provide long-term price stability. Given the relatively short-term BGS contract cycle and given New Jersey's large RPS goals for in-state solar, one of the most expensive resources to develop, it is imperative for New Jersey to address the issue of price certainty in order to keep RPS compliance costs from reaching the cap set by future ACP and SACP levels. In addition, it is critical for New Jersey to consider setting the ACP and SACP levels high enough above REC/SREC pricing levels necessary to deliver target project IRRs in order to keep the alternative compliance mechanisms from having too much influence on REC/SREC pricing.

Table 4-1. Early RPS Experience

State & First Compliance Year	Comments
Arizona (2001)[34]	• As of 2004, RPS-obligated entities had reportedly fallen short of compliance without repercussions.[35]
California (2003)[36]	• SBC funds are used to cover above-market RPS compliance costs. • Utilities enter into 10-20 year contracts with projects (required to offer 10-year minimum). For PG&E, all contracts to date except one have been for values less than the "Market Price Referent," currently set at $0.085/kWh.[37] • 62 contracts for eligible resources have been approved by CPUC since 2002. Based on current and pending contracts, CPUC expects that new (post 2002) resources will account for 46% of portfolio requirement in 2010. • Geothermal expected to account for largest portion of the portfolio; over 6,000 GWh expected to be produced by 2010. Wind, biomass and solar thermal expected to make up largest portion of remaining portfolio target by 2010; 2,000 GWh from wind, 1,500 GWh from biomass, and 1,200 GWh from solar thermal electric. Expect greatest growth in solar thermal, geothermal, and biomass. • In 2005, utility renewables percentages were: PG&E, 11.8%; SCE, 17.7%; SDG&E, 5.2%.
Connecticut (2000)[38]	• For the 2004 compliance year (most recent available data), all obligated entities complied through REC procurement. No ACPs were made. • Class I CT REC trading values ranged from $35-$40/MWh. Class II CT REC trading values ranged from $0.50-$0.75/MWh.[39]

[34] Solar Portfolio Standard was in place in 1999, but first compliance year for multi-attribute RPS was 2001.

[35] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

[36] Unless otherwise noted, data on California's RPS experience is sourced from: California Public Utilities Commission, "Progress of the California Renewable Portfolio Standard As Required by the Supplemental Report of the 2006 Budget Act." Report to the Legislature, January, 2007.

[37] California regulators periodically set a "Market Referent Price." It is set based on natural gas pricing (10 year forward curve) and is intended to estimate the marginal price of the next unit of generating capacity to go online. If renewable energy projects exceed the Market Referent Price, they can apply for Supplemental Energy Payments. Hal LaFlash, PG&E, "CA S.B. 107" Presentation at EUCI RPS Conference, Westminster, CO, April 23, 2007.

[38] Original compliance year was 2000, though there were many loopholes (only applied to competitive suppliers and suppliers could defer compliance for up to two years). Revisions to the RPS law were passed in 2003 which held all suppliers to compliance and the first compliance year under the new rules was 2004.

[39] Data for the 2004 compliance year are the most current that are available. Connecticut Public Utility Control. "DPUC Review of Renewable Portfolio Standards Compliance for 2004." Docket No. 05-11-01. March, 2006.

State & First Compliance Year	Comments
Iowa (1999)	• As of 2004, after having experienced compliance delays, the state saw "reasonably stable costs supported by end-users."[40]
Maine (2000)	• No cost impacts since requirements set below level of renewable energy already generated in the state.
Massachusetts[41] (2003)	• For the 2005 compliance year (most recent available data), 35% of the RPS target (2% of the state's electricity sales) was met through ACP, totaling over $19.5M in ACPs. • Biomass and landfill gas have supplied the vast majority of output counted toward RPS compliance. • 24.4% of RECs used for compliance came from generators located within MA. Remaining RECs came from generators elsewhere in New England and New York. • ACP funds used by Massachusetts Technology Collaborative (MTC) to support further development of renewable energy resources. • Shortage of eligible supply has driven MA REC trading values to ACP level of $50/MWh. • Limited long-term contracting occurring, so substantial amount of compliance REC-based compliance occurring through short-term market transactions. • MTC's Massachusetts Green Power Partnership addressing difficulties with long-term contracting by offering REC floor price for select utility-scale projects.[42]
Nevada (2001)	• As of 2004, RPS was effectively driving development of new resources with contract pricing ranging from 3-5.5 cents/kWh.[43] • 287 MW of geothermal, wind and solar resources are under contract with utilities for ~20 year terms.[44] • RPS-obligated entities have fallen short of compliance in the past, but expanded eligibility requirements under new RPS requirements (updated in 2005) increase the likelihood of future compliance.

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[40] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

[41] Massachusetts Division of Energy Resources. "Massachusetts Renewable Energy Portfolio Standard Annual RPS Compliance Report for 2005." February, 2007.

[42] Further information on the Massachusetts Green Power Partnership is available at http://www.mtpc.org/renewableenergy/mgpp.htm

[43] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

[44] Nevada Public Utilities Commission: http://www.puc.state.nv.us/renewable_energy.htm.

State & First Compliance Year	Comments
New Jersey (2001)[45]	• A total of 19 ACPs were made toward Class I compliance ($950 revenue), and 163 SACPs were made toward solar compliance ($48,900 revenue). • Of the Class I RECs that were contracted for directly by suppliers, all came from landfill gas plants located in New Jersey.
New Mexico[46] (2006)	• For first compliance year (2006), all utilities are expected to fulfill requirements. • REC expenditures ($/kWh) are limited to "reasonable cost thresholds" and different levels have been determined for each qualifying resource. • Overall RPS compliance costs must not exceed lesser of 1% of customers' annual electric bill or $49,000 per utility in 2006, increasing incrementally to 2% of customers' annual electric bill or $99,000 (adjusted for inflation) per utility in 2011. • Penalty costs range from $100 to $100,000 for each offense
New York[47]	• $764.4 million in funding will be collected through RPS charge on customer bills through 2013. • NYSERDA plays central procurement role, purchasing renewable energy attributes / RECs on behalf of ratepayers. Enter into contracts with suppliers, between 3-10 years in length. • $500.4 million is committed to "Main-Tier" contracts. • $45 million in funding authorized for spending on "Customer-Sited Tier." • Main Tier contracts expected to result in ~844 MW of projects (primarily wind) serving NYSERDA RPS. However, 1,200 total new capacity will be developed by end of 2008 program year.[48] • Weighted REC price for Main Tier contracts is $17/MWh. • Expected to meet 80% of 2008 program goal.
Texas (2002)	• Deemed lowest cost RPS compliance costs of any state. • Long-term wind contract pricing in 3 cent/kWh range.[49] • In 2006, surpassed 2009 RPS goal to install 2,800 MW of renewable energy capacity (equaled about 2.1% of all electricity generated in the state and came largely from wind).[50] • Based on a drop in REC pricing from $12.30/MWh in 2005 to $4/MWh in 2006, the ratepayer impact of RPS compliance was believed to be lower in 2006 than in 2005. However, there is no requirement for electricity suppliers to pass on to customers the cost/savings associated with RPS compliance.[51]

[45] New Jersey BPU RPS compliance records for 2006 reporting year.

[46] New Mexico Public Regulation Commission RPS compliance estimates for 2006: http://www.nmprc.state.nm.us/renewable.htm; and California Public Utilities Commission. "Renewable Energy Certificates and the California Renewable Energy Portfolio Standard Program." Staff White Paper. April, 2006. Completion of New Mexico's first RPS compliance report is expected in September, 2007.

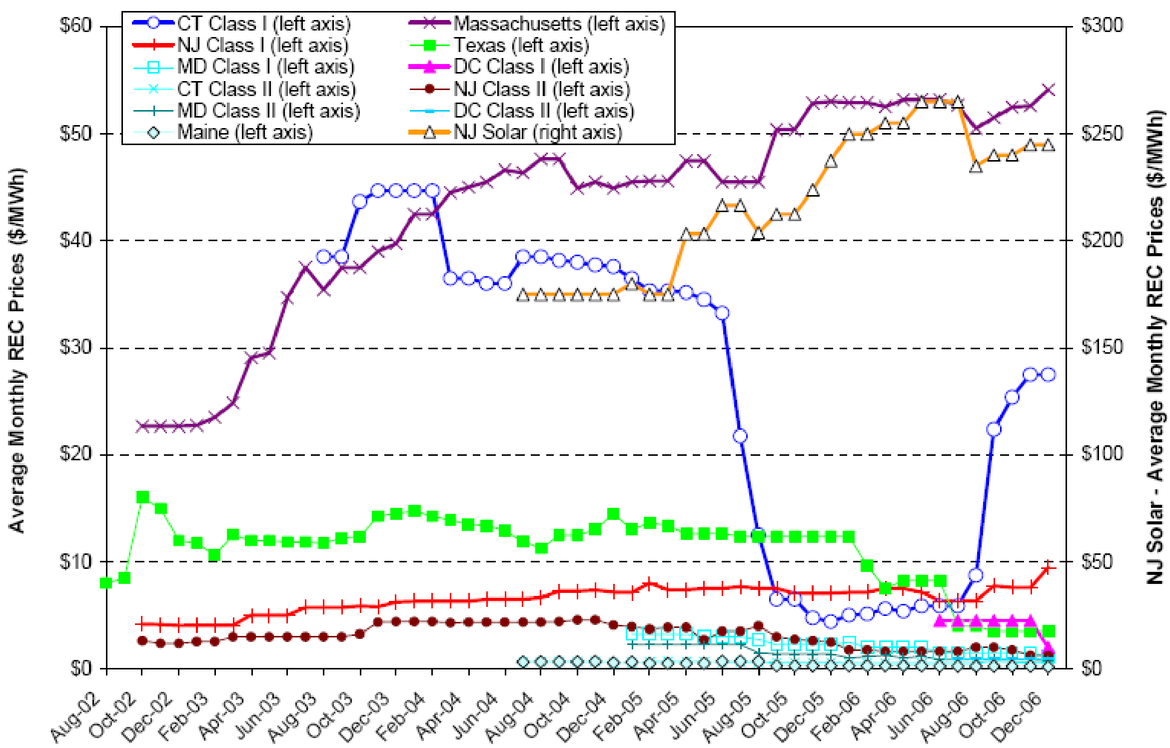
[47] John Saintcross, "New York State Renewable Portfolio Standard." Presentation at EUCI RPS Conference, Westminster, CO, April 23, 2007.

[48] NYSERDA contracts leverage more capacity development than is actually procured by NYSERDA. NYSERDA will not procure more than 95% of any facility's output, as NYSERDA wishes to leave capacity available to serve the voluntary market.

[49] Wiser, Ryan, Kevin Porter and Robert Grace. "Evaluating Experience with Renewables Portfolio Standards in the United States." Ernest Orlando Lawrence Berkeley National Laboratory. March, 2004.

In the absence of more robust empirical data regarding early RPS compliance costs, one can look to REC pricing as one indicator of RPS cost impacts. Figure 4-1, presents REC pricing data for RPS markets that use RECs to demonstrate compliance. These data were collected by the Lawrence Berkeley National Laboratory based on monthly market reports produced by REC broker, Evolution Markets. It is important to recognize that the Evolution Markets' pricing summary does not reflect all trades occurring in the markets. However, the REC pricing data does provide an indication of the relative value of RECs in different markets. As shown, New Jersey's solar RECs are by far the highest priced RECs on the market followed by Massachusetts RECs and Connecticut Class I RECs. In markets where supply of RPS-eligible resources is less constrained, REC prices are much lower.

Figure 4-1. REC Pricing



Source: Wiser, R. C. Namovicz, M. Gielecki, and R. Smith. "Renewables Portfolio Standards: A Factual Introduction to Experience from the United States." Lawrence Berkeley National Laboratory, April, 2007. Based on data from Evolution Market's monthly pricing reports compiled by Lawrence Berkeley National Laboratory.Evolution Markets.

4.2 Projected RPS Ratepayer Impacts

In March 2007, Lawrence Berkeley National Laboratory (LBNL) released a report which reviewed 28 RPS cost studies that have been conducted since 1998 for 18 states across the U.S.[52] Seventy percent of RPS cost studies reviewed predict that retail rates will increase by no more than one percent under base-

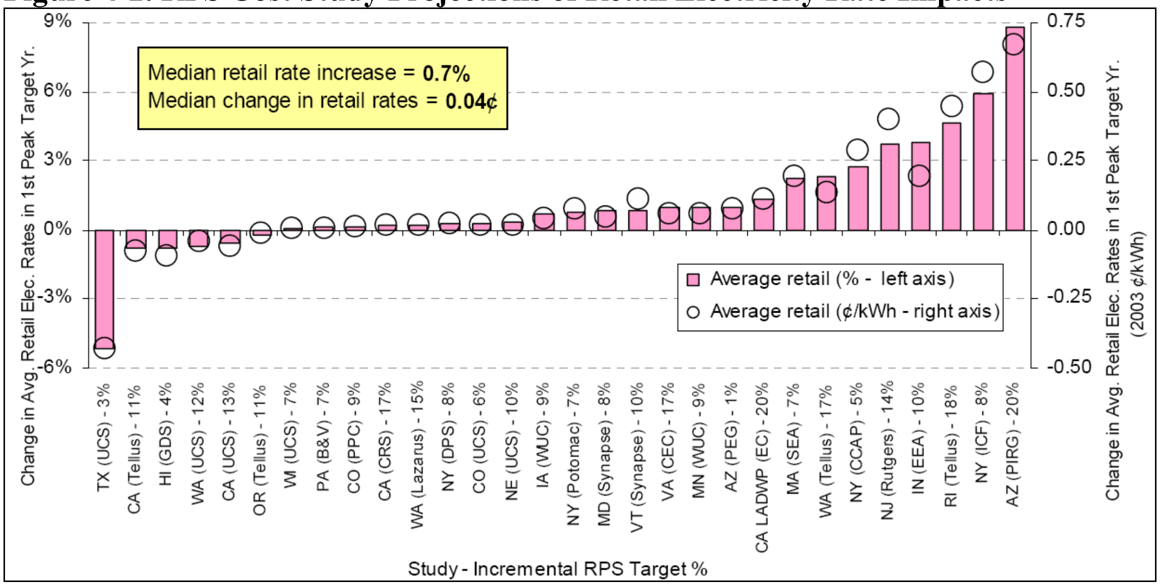
[50] Public Utility Commission of Texas. "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas." January, 2007.

[51] Ibid.

[52] Chen, Cliff, Ryan Wiser and Mark Bolinger. (2007) "Weighing the Costs and Benefits of State Renewables Portfolio Standards: a Comparative Analysis of State-Level Policy Impact Projections." Ernest Orlando Lawrence Berkeley National Laboratory.

case conditions in the year in which the RPS policy reaches its peak percentage target. The median retail rate increase projected by the studies reviewed was 0.7 percent, and the median increase in retail rates projected by the studies reviewed was $0.04 per kWh (Figure 4-2). The median bill impact across all of the studies was $0.38 per month.

Figure 4-2. RPS Cost Study Projections of Retail Electricity Rate Impacts



Source: Chen, Cliff, Ryan Wiser and Mark Bolinger. (2007) "Weighing the Costs and Benefits of State Renewables Portfolio Standards: a Comparative Analysis of State-Level Policy Impact Projections." Ernest Orlando Lawrence Berkeley National Laboratory.

While the median projected rate impacts are moderate, the range in results across studies is significant. Furthermore, the LBNL study highlights the importance of conducting sensitivity analyses with its findings that the cost projections are highly sensitive to modeling assumptions, and that the majority of studies reviewed underestimated wind power capital costs and natural gas prices in their modeling assumptions. According to the authors, these cost categories are critical, as wind is expected to account for the majority of RPS supply, and natural gas prices are central to projections of avoided costs resulting from renewable energy supply. The authors explain that the effects of underestimating the two cost categories could counter one another, but that the extent of this potential canceling out effect is unknown.

The authors present several recommendations regarding improvements that could be made in designing future RPS cost studies. Of note among those recommendations is the need for: 1) more careful consideration of transmission costs, integration costs and capacity value; 2) a recognition of the impacts of future carbon regulations and RPS policies coming into effect in neighboring states; and 3) greater recognition of public benefits (i.e., job creation, hedge value of renewables) and improvements in the assumptions used to calculate projections of macroeconomic benefits.

4.3 Renewable Energy SBC Spending

In addition to reviewing broader indicators of the ratepayer impacts of RPS policies in other states, the Team collected data on the renewable energy Systems Benefit Charge (SBC) funds in place in many states. In many cases, these funds exist to provide direct financial support for renewable energy project development. Of the 24 jurisdictions with RPS policies, 15 states also collect SBC funds to support renewable energy development. New York and California use SBC funding alone to pay for the above-market costs of renewable energy used for RPS compliance (i.e., there is no additional pass-through of RPS compliance costs to ratepayers). However, it is more common for states to pass the costs of RPS compliance through to ratepayers through more standard rate recovery procedures. In either case, SBC spending plays an integral role in supporting renewable energy development that will ultimately contribute to RPS compliance. While SBC funding levels are not necessarily linked to a state's ultimate RPS compliance costs, SBC funding is an indicator of a state's commitment to invest in renewable energy development. A summary of state renewable energy SBC funding is included in Appendix C.

5. ADDITIONAL BENEFITS OF RPS

Ratepayer impacts associated with state funding for solar project development must be viewed in the context of the broader economic, environmental, and health impacts that will also result. Two studies have examined the economic impacts of New Jersey's RPS.

The first was Rutgers University's December, 2004 report, "Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard." The research team used the Rutgers Economic Advisory Service Econometric Model of the New Jersey Economy (R/ECON™) as the basis for calculating estimated impacts of a 20% by 2020 RPS on New Jersey's economy. The study examined impacts under a variety of scenarios; key scenarios included low vs. high energy prices, as well as an expected rate vs. an historic rate of reduction in technology costs over time. Key findings from the study, based on the assumption that technology costs decrease at the expected rate, include:

- Compared to the impacts of the RPS goals that existed at the time of the study, electricity prices would rise by 3.7 percent between 2004 and 2020 as a result of the 20% RPS.[53]
- Assuming that all jobs associated with manufacturing, installing and supporting renewable energy installations associated with meeting the RPS are kept in New Jersey, the 20% RPS is projected to add a total of 11,700 jobs to the state by 2020. On an annual basis, those jobs would support $1 billion in gross state product, including $700 million in job earnings and $77 million in state and local tax revenues.[54]
- By reducing demand for natural gas, the RPS would put downward pressure on natural gas prices.
- Increased renewable energy system availability would improve electric system reliability.
- Reduced air emissions would result in several hundred million dollars of avoided costs, such as avoided health care costs and other costs pertaining to the reductions in environmental quality that would occur in the absence of the 20% RPS.[55]

The projected benefits presented in the Rutgers study hinge on the very uncertain assumption that installed costs for PV and wind projects will decline at rates higher than have historically existed. In fact, if technology costs only decline at historical rates,[56] the Rutgers study estimates that electricity prices will rise by 24 percent in 2020 as a result of the 20% RPS. This would result in substantial negative economic impacts by 2020, including 2,000 fewer jobs than would exist if the RPS were not increased to 20% by 2020.

A second study examining the economic impacts of the New Jersey RPS was completed in June 2006. That report, "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey," by Cureington, et al. uses input assumptions similar to those used in the Rutgers study for electricity demand projections and historic rates of technology cost reductions. However, the study finds that increases in electricity prices will have much more negative impacts on the economy than is assumed in the Rutgers study. The authors conducted their analysis using New Jersey-specific inputs in the IMPLAN Economic

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[53] The existing RPS target was for 6.5% of the state's electricity to be supplied from renewables by 2009.

[54] This annual economic impact pertains to the year 2020 and beyond and is presented in year 2000 dollars.

[55] Due to the extensive New Jersey specific data and modeling that would be required to arrive at precise estimates of the avoided costs associated with RPS-related emissions reductions, the Rutgers research team instead used externality adders from other studies perform illustrative calculations and arrive a range for the value of avoided emission-related costs.

[56] These historical rates presented in the 2004 Navigant Market Assessment report for New Jersey are 5 percent per year for solar and 2.5 percent per year for wind.

Impact Assessment Model, a model which has been used across a number of industries, and in several other states' RPS cost impact assessments.[57]

The Cureington report recognizes that renewable energy development would result in job growth and other economic benefits, but states that these benefits would be far outweighed by negative impacts, producing substantial net negative impacts on the economy. The authors factor in losses in benefits that would have resulted if the electric demand met by renewables under the RPS was instead met with increases in fossil fuel power generators. The authors challenge the Rutgers study's assumption that renewables development under the RPS would have measurable impact on natural gas prices since New Jersey's natural gas usage accounts for such a small percentage of total U.S. consumption.[58] Finally, the authors assume that much of the renewable energy development that occurs under New Jersey's RPS would be built with equipment manufactured outside the state, and that a large percentage of the economic benefit associated with renewable energy development in New Jersey would "leak" out of the state as a result.

The Cureington study finds that the 20% by 2020 RPS will increase electricity expenditures by $3.3 billion during the period 2005 to 2021 compared to the state's previous RPS levels. This would result in a $7 billion cumulative NPV decrease in the net output of New Jersey's economy over the next 20 years. These findings are based on the assumption that technology costs will continue to decrease at historical rates. The authors highlight that the negative impacts of the RPS would be much greater if technology costs do not continue to decline in the future. The study does not factor in the value of environmental and health benefits.

As both studies point out, predicting economic impacts so far into the future is challenging and heavily dependent on the assumptions used. A recent report released by Lawrence Berkeley National Laboratory examined RPS cost impact studies conducted across the country, including the Rutgers study for New Jersey. The report notes that many RPS cost studies use dated assumptions about technology costs and highlights the importance of updating cost assumptions for future studies. Like the authors of the Rutgers report, the authors of the LBNL report emphasize the need for RPS impact studies to recognize the effect that reduced fossil fuel consumption will have on natural gas prices. The authors of the LBNL report explain that these impacts will play out in the form of both lower electricity prices and lower end-use natural gas prices.

For reference Table 5-1 below shows how the Rutgers study compared to other studies examined in the LBNL study in its estimation of net jobs created and impacts on gross state product.

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[57] Other RPS cost impact studies using the IMPLAN model include those conducted for Arizona, Wisconsin, Nebraska, Colorado, Texas and Washington. Chen, C., R. Wiser, M. Bolinger. (2007) "Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections." Ernest Orlando Lawrence Berkeley National Laboratory.

[58] The Cureington study stated that New Jersey's natural gas consumption accounted for less than one percent of total U.S. consumption in 2004.

Table 5-1. Employment and Gross State Product Impacts Projected in RPS Cost Studies

Cost Study	Incremental Net Jobs In Peak Target Year	Timeframe of Analysis	Cumulative Incremental RPS Target (GWh)	Change in Gross State Product ($2003 Millions)	Model Used
Arizona (PIRG)	308	2005-2020	96,500	$374 (in 2020)	IMPLAN
Wisconsin (UCS)	380	2006-2020	61,300	$95 (in 2020)	IMPLAN
Nebraska (UCS)	357	2003-2012	14,500	$37 (in 2012)	IMPLAN
Arizona (PEG)	600	1998-2010	5,700	n/a	Spreadsheet
Colorado (UCS)	1,290	2005-2020	46,500	$51 (in 2015)	IMPLAN
Pennsylvania (B&V)	3,747	2006-2025	186,600	$9,038	RIMS II
New Jersey (Rutgers)	2,600-11,700	2005-2020	90,300	$203-1014 (in 2020)	R/ECON I-O
Texas (UCS)	14,600	2005-2025	225,800	$61 (in 2025)	IMPLAN
Washington (UCS)	30	2010-2025	76,400	$10 (in 2020)	IMPLAN

Note: All employment figures represent employment gains that occur in the state of the modeled state RPS. The employment figures from Pennsylvania (B&V) are based on a model of the state's Alternative Energy Portfolio Standard, which includes requirements for energy efficiency and other "Tier II" alternate (mostly non-renewable) energy sources. Employment and gross state product figures from Washington (UCS) represent only the impacts of the renewable energy additions of the state RPS (the study also models an efficiency standard), and do not include induced impacts from energy price changes. The Pennsylvania and Arizona employment figures are calculated by dividing the job-years reported in the studies by the length of the study's timeframe. Lower and upper bounds of range of New Jersey (Rutgers) impacts represent results from two renewable technology manufacturing scenarios: one in which all renewable technology is manufactured out-of-state, and one in which 100% of renewable technology is manufactured in-state (the data in Figure 14 represents the average of these two scenarios). Wisconsin (UCS) provides Scenario 2 results in the report text, but data shown here is from Scenario 1 (to be consistent with our base-case designation).

Source: Chen, C., R. Wiser, M. Bolinger. (2007) "Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections." Ernest Orlando Lawrence Berkeley National Laboratory.

The projections presented in the Rutgers and Cureington reports would not be substantially affected by BPU's choice regarding a future solar incentive model. As long as New Jersey can succeed in achieving its RPS targets, including developing the amount of solar capacity necessary to generate electricity equivalent to the target 2.12% of electricity sales in the state by 2021, the environmental and health benefits estimated in the Rutgers report would result regardless of the associated cost to ratepayer.[59] However, the net value of these benefits will be greater if New Jersey can achieve the required solar development at a lower cost to ratepayers. Assuming that the RPS produces net negative economic impacts, these would be lessened somewhat by implementation of a more cost-effective solar incentive program. Furthermore, it is worth noting the model used for this analysis incorporates some more current assumptions than were included in the Rutgers and Cureington studies which, if applied in those studies, would produce somewhat different result than were included in the ratepayer impact projections presented in those reports.

[59] The environmental and health benefits projected in the Rutgers report are based on assumptions about the distribution of technologies that are used to meet the non-solar portion of the RPS.

APPENDIX A:

NEW JERSEY FORECASTED ENERGY CONSUMPTION

AND

SOLAR RPS REQUIREMENT

Energy Year ending in	Total Electric Sales (PJM Projection) (MWh)	Solar Electric Generation (RPS Requirement) (%)	Solar RPS Requirement (MWh/yr)	Generation from new PV capacity (MWh/yr)
2007	73,800,000	0.039%	29,003	29,003
2008	74,907,000	0.082%	61,199	32,196
2009	76,030,605	0.160%	121,649	60,450
2010	77,171,064	0.221%	170,548	48,899
2011	78,328,630	0.305%	238,902	68,354
2012	79,503,559	0.394%	313,244	74,342
2013	80,696,113	0.497%	401,060	87,816
2014	81,906,555	0.621%	508,640	107,580
2015	83,135,153	0.765%	635,984	127,344
2016	84,382,180	0.928%	783,067	147,083
2017	85,647,913	1.118%	957,544	174,477
2018	86,932,632	1.333%	1,158,812	201,268
2019	88,236,621	1.572%	1,387,080	228,268
2020	89,560,170	1.836%	1,644,325	257,245
2021	90,903,573	2.120%	1,927,156	282,831
2022	92,267,127	2.120%	1,956,063	
2023	93,651,133	2.120%	1,985,404	
2024	95,055,900	2.120%	2,015,185	
2025	96,481,739	2.120%	2,045,413	
2026	97,928,965	2.120%	2,076,094	
2027	99,397,899	2.120%	2,107,235	
2028	100,888,868	2.120%	2,138,844	
2029	102,402,201	2.120%	2,170,927	
2030	103,938,234	2.120%	2,203,491	
2031	105,497,308	2.120%	2,236,543	
2032	107,079,767	2.120%	2,270,091	
2033	108,685,964	2.120%	2,304,142	
2034	110,316,253	2.120%	2,338,705	
2035	111,970,997	2.120%	2,373,785	
Total	113,650,562	2.120%	2,409,392	

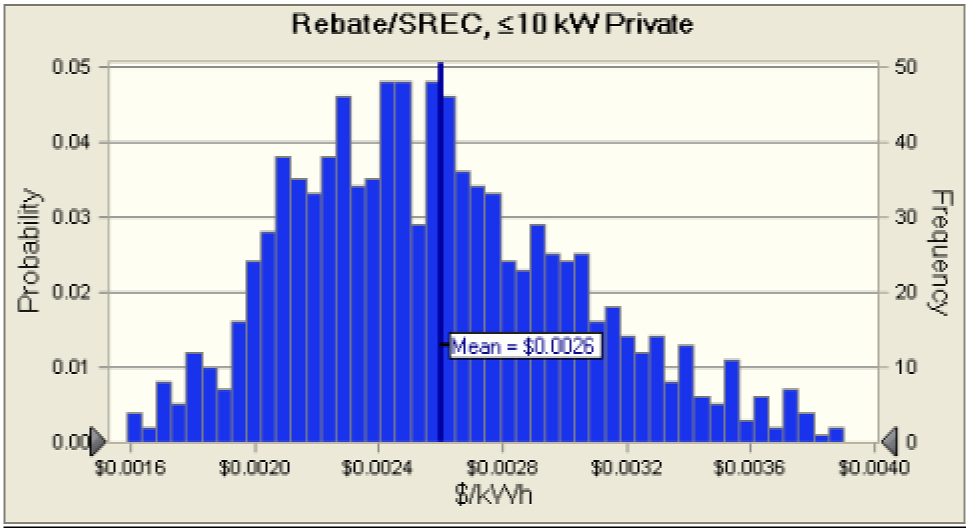
Source: BPU OCE and PJM project growth rate of 1.5% (http://www.pjm.com/contributions/news-releases/2007/20070116-2007-load-forecast-report.pdf)

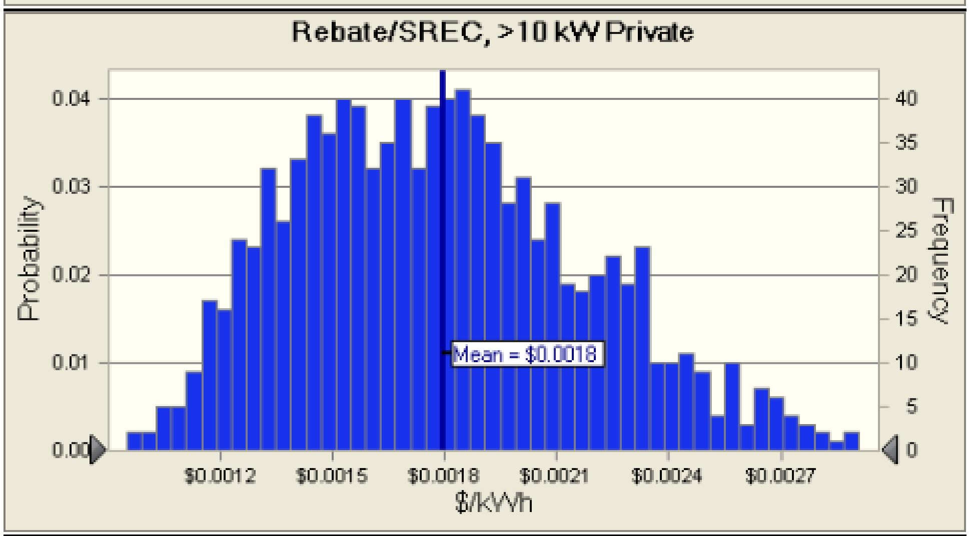
APPENDIX B:

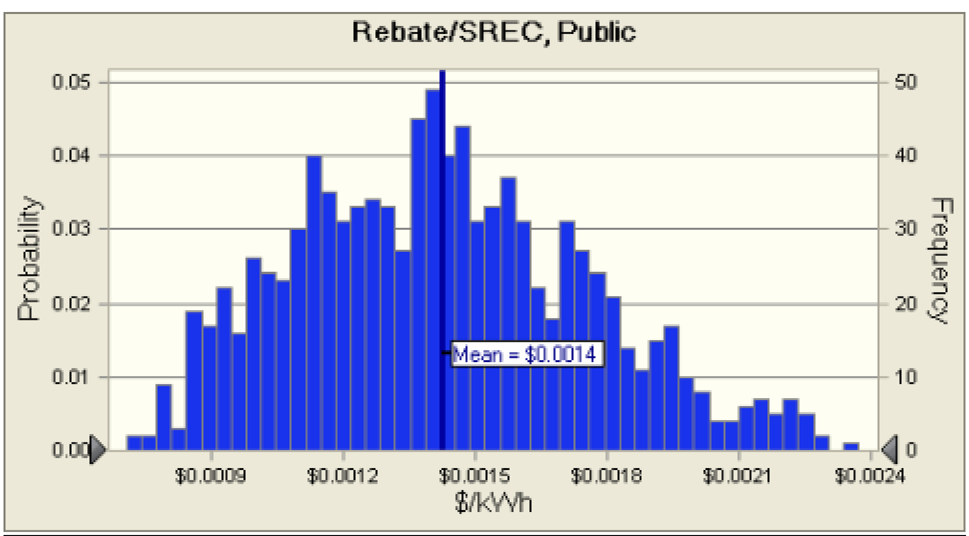
MONTE CARLO SIMULATION

RPI PROBABILITY DISTRIBUTION CHARTS

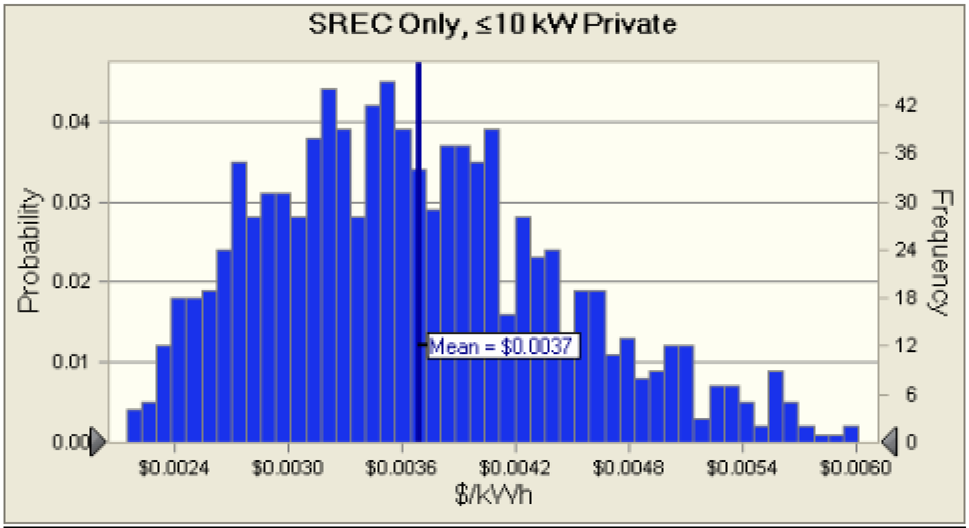
Rebate/SREC Model

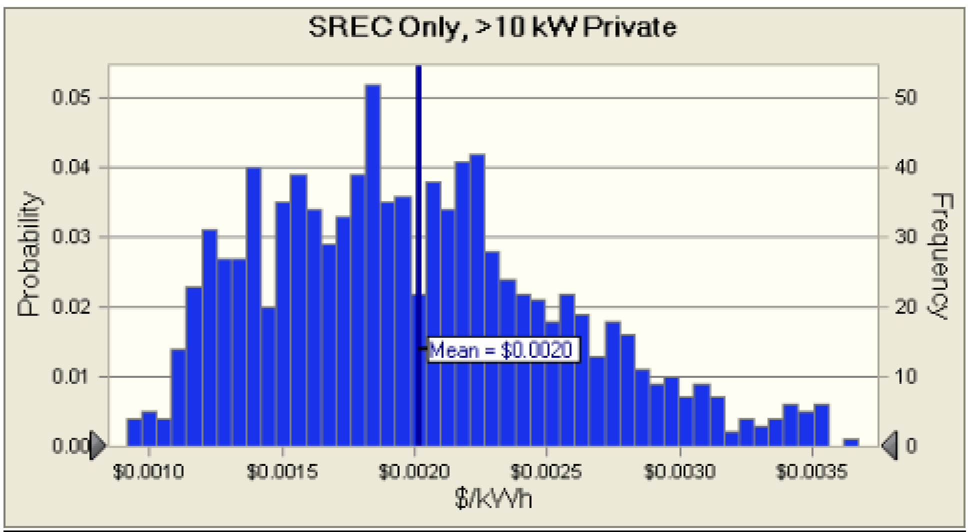


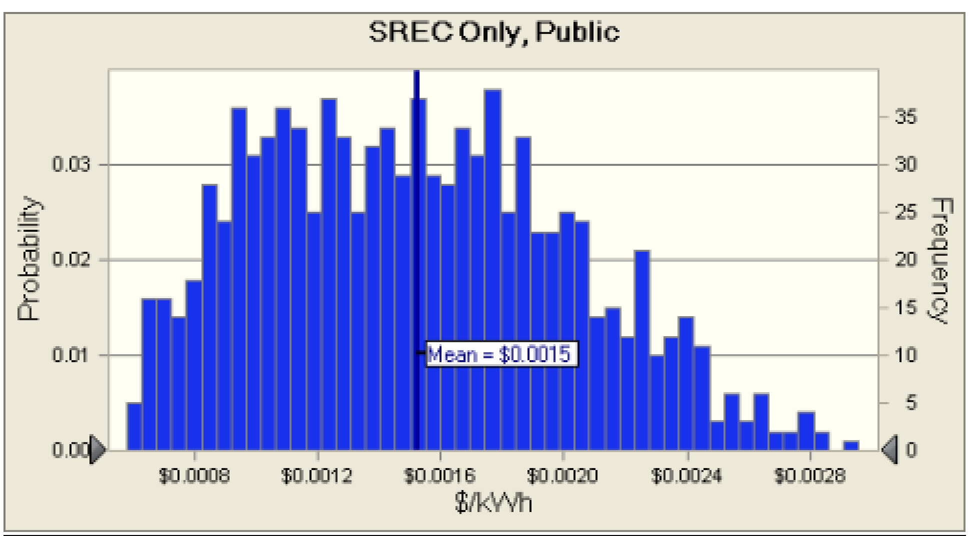




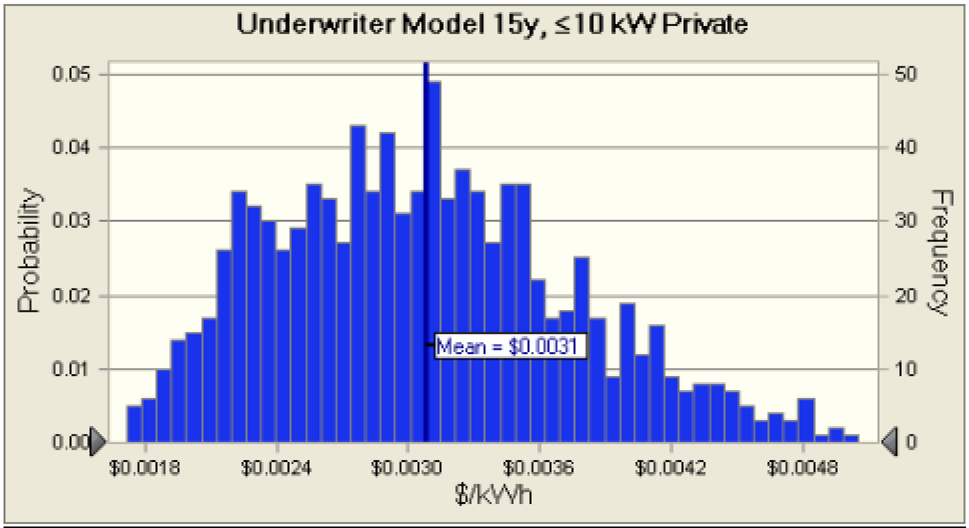
SREC Only Model

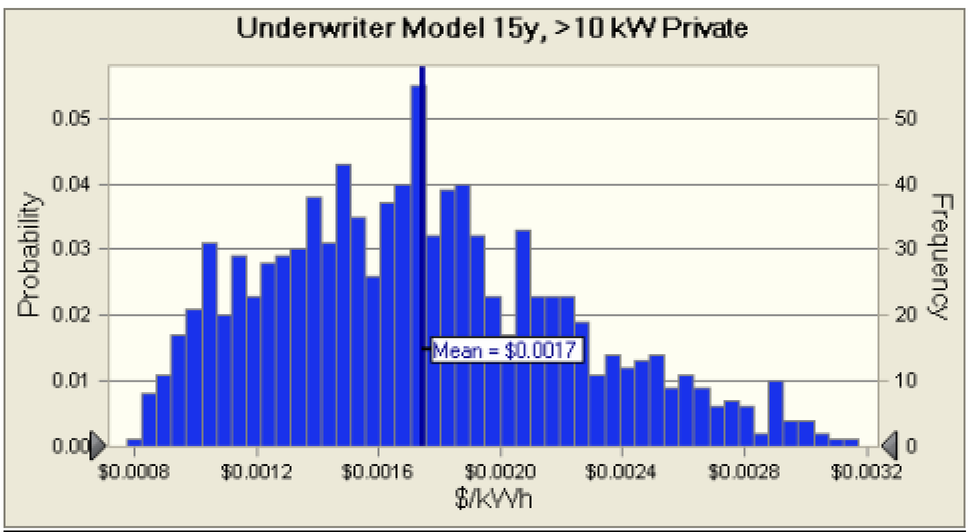


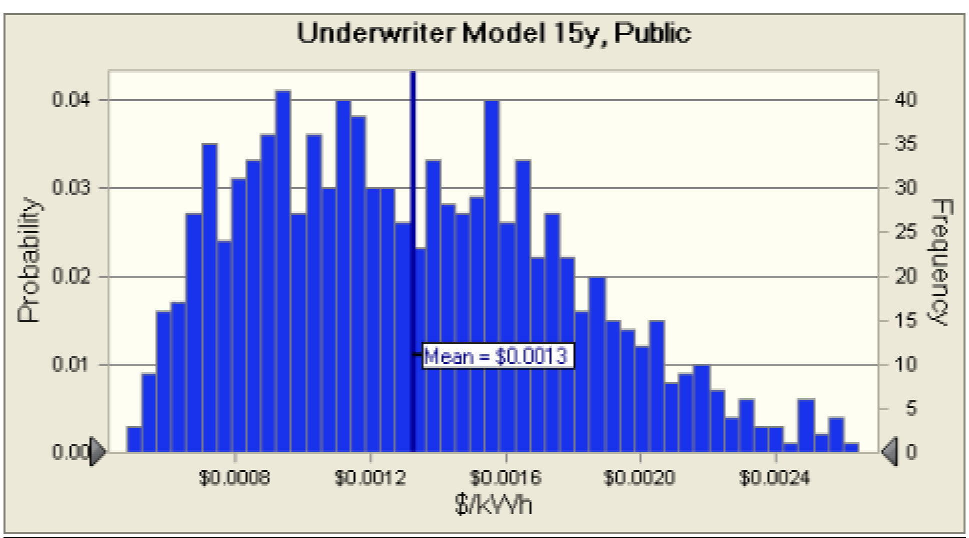




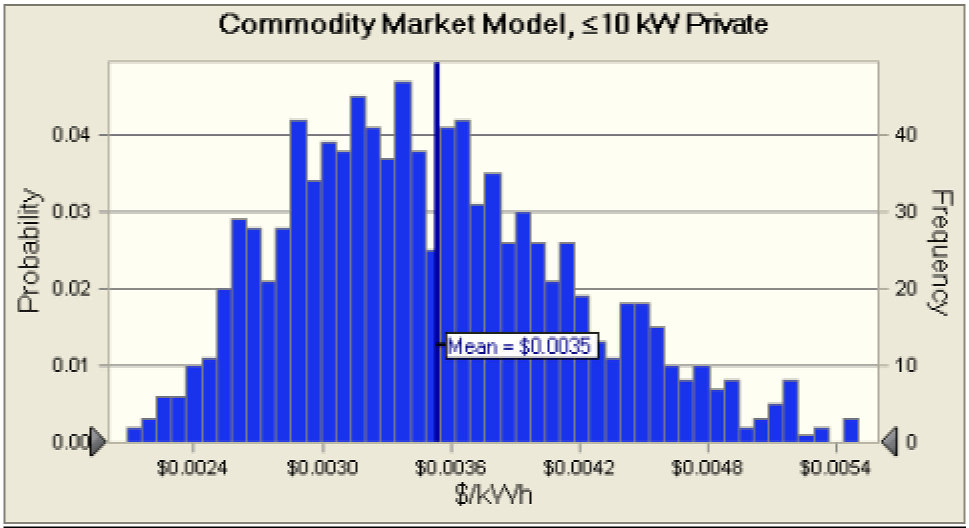
Underwriter Model

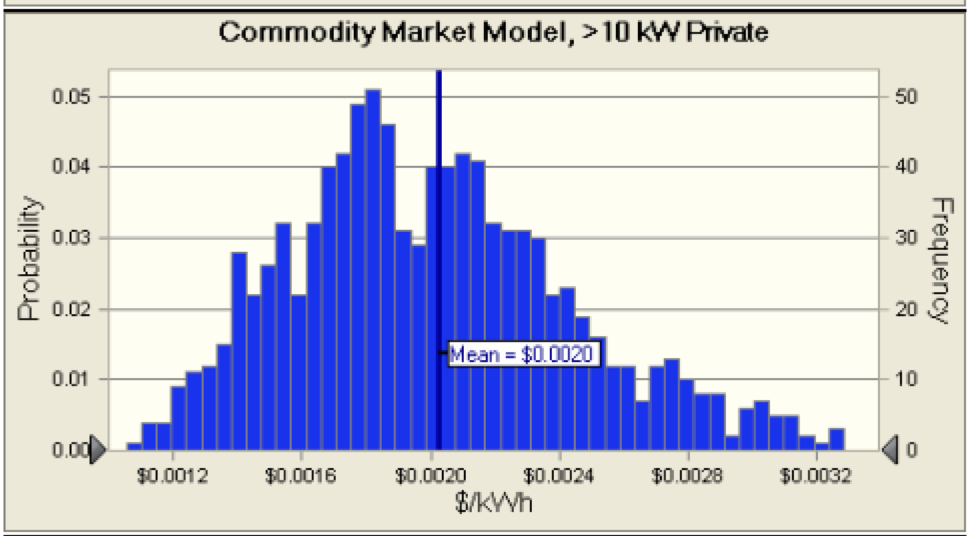


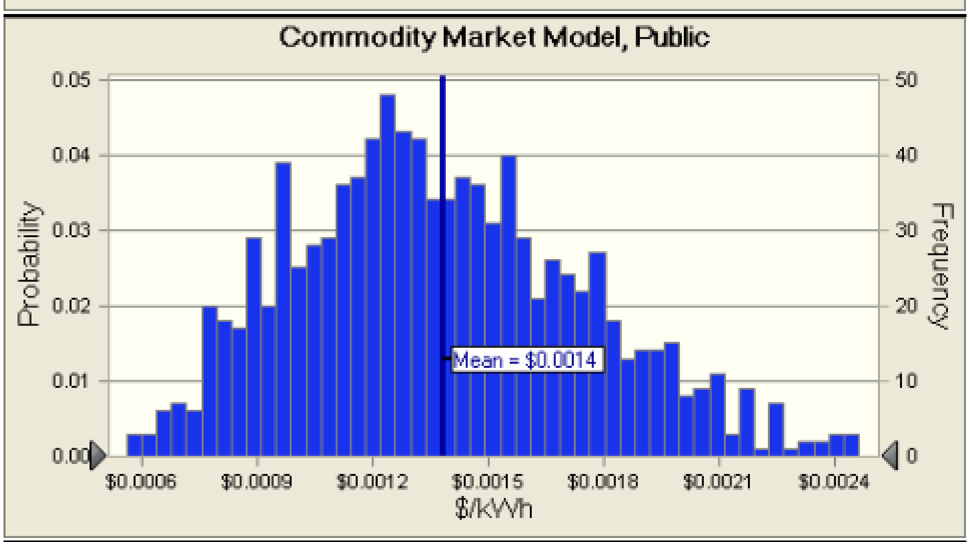




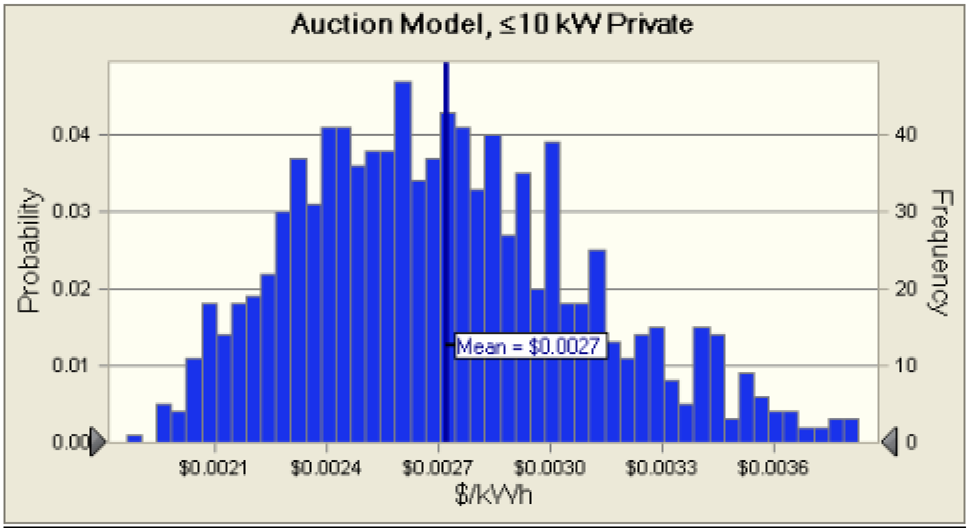
Commodity Market Model

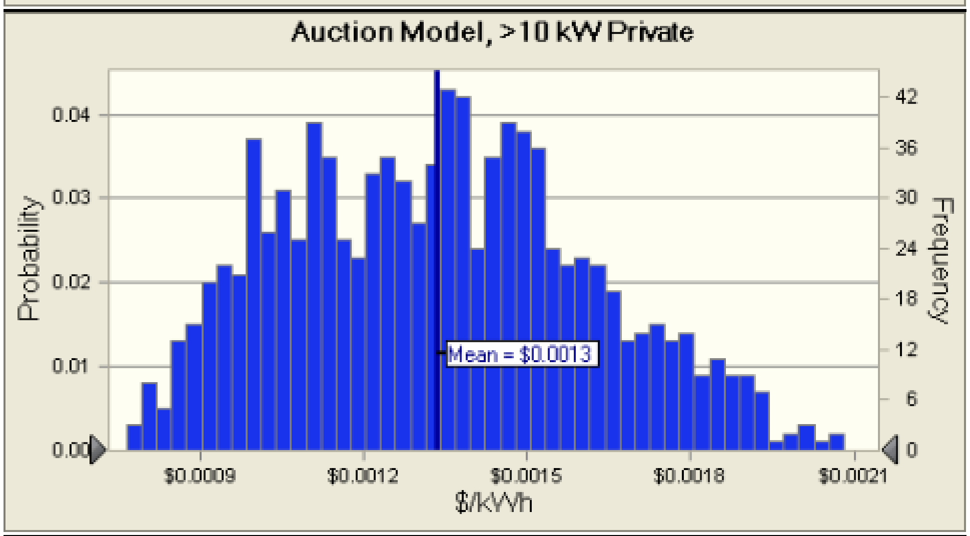


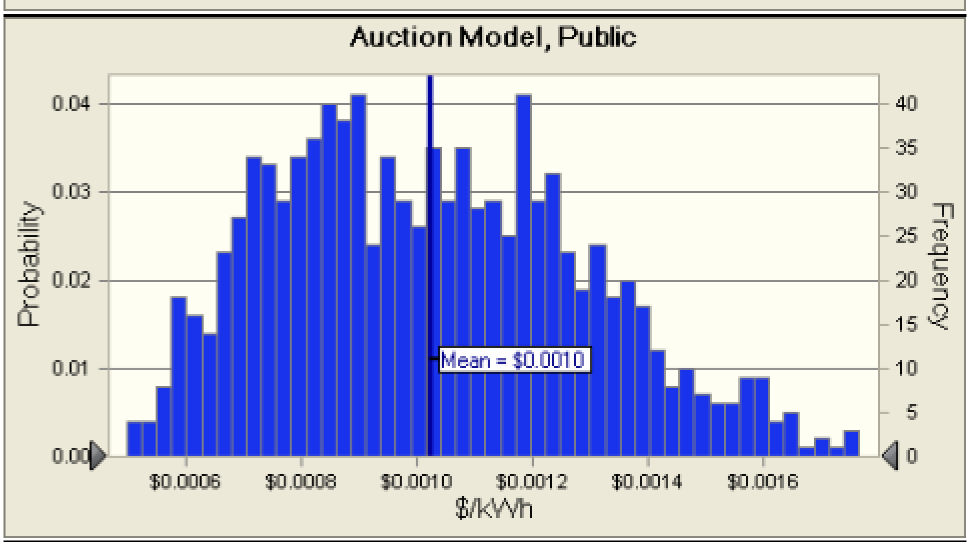




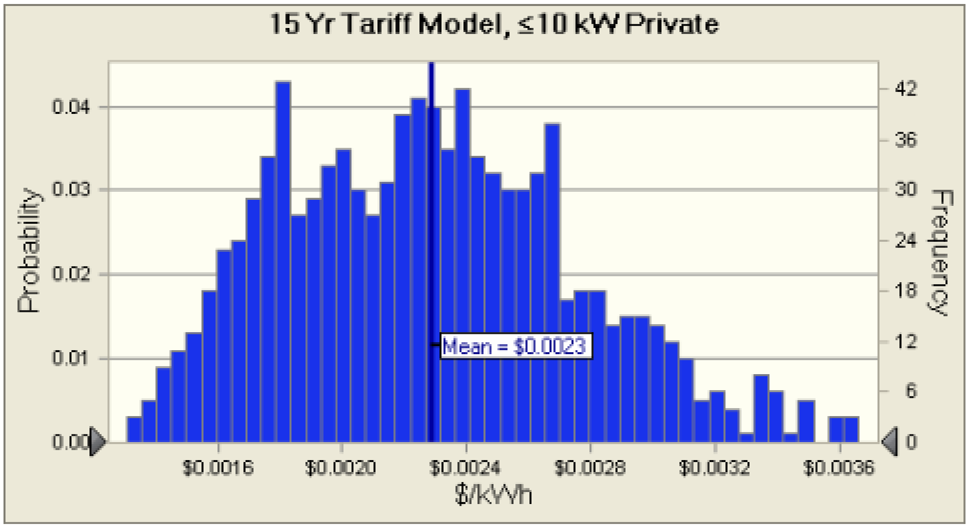
Auction Model

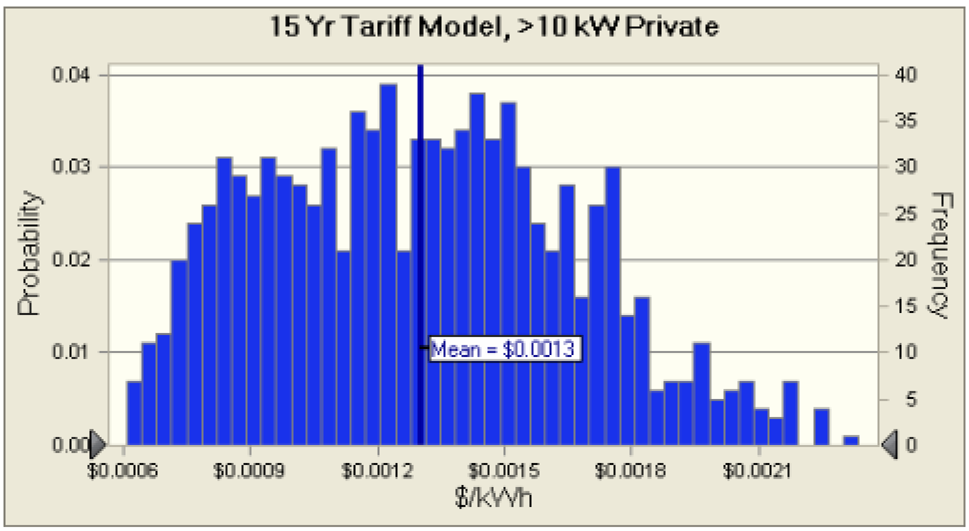


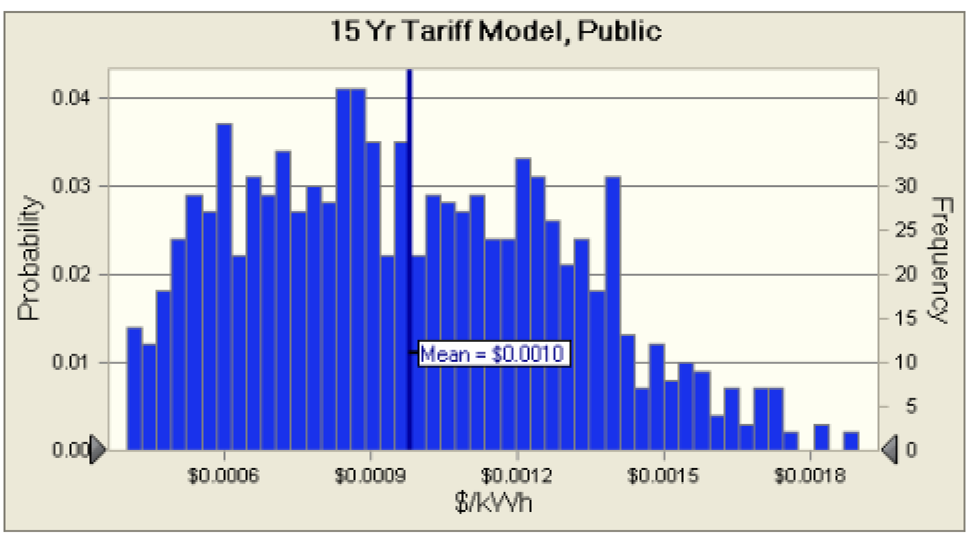




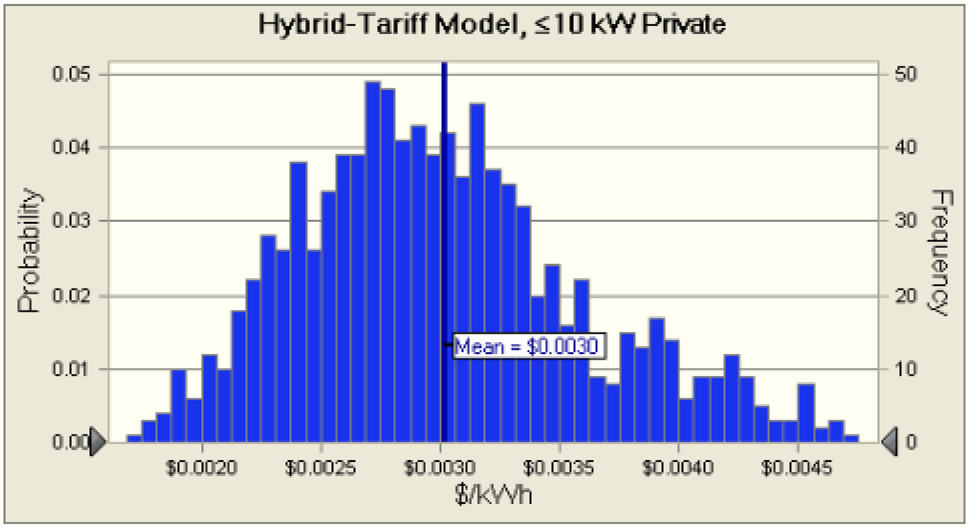
15 Yr Tariff Model

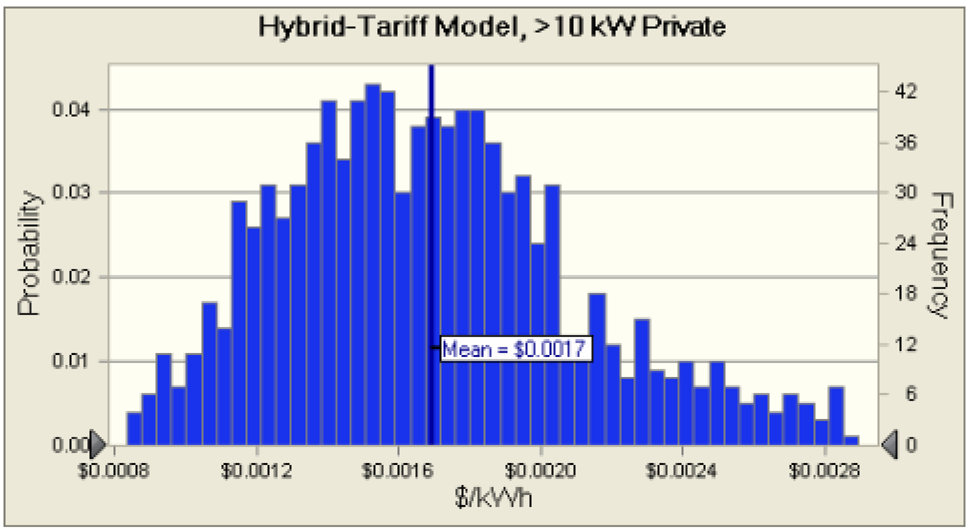


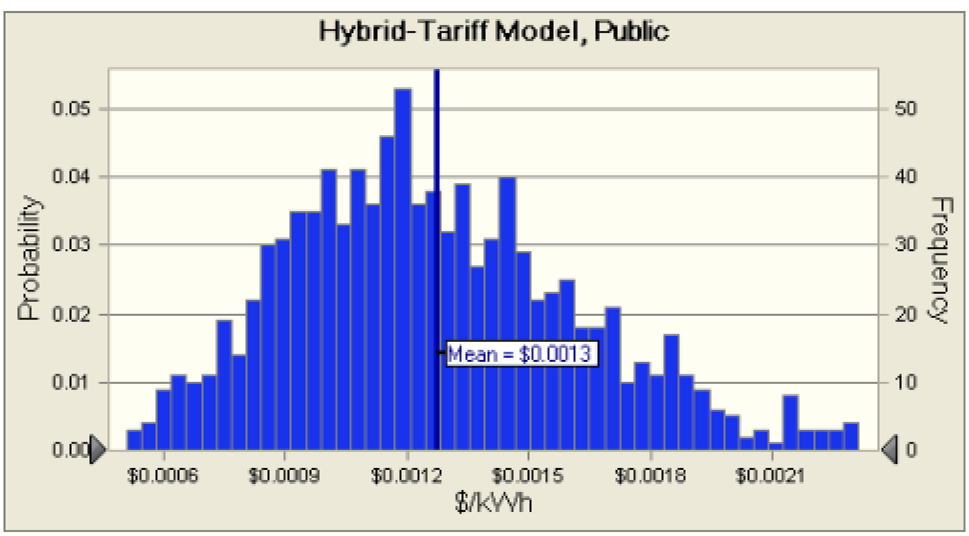




Hybrid-Tariff Model







APPENDIX C:

BOARD ORDERED SACP RESEARCH ISSUES

The State of New Jersey Board of Public Utilities

Docket No. EO06100744

Recommendations for Alternative Compliance Payments and Solar Alternative Compliance Payments for Energy Year 2008. A Stakeholder Process Regarding Alternative Compliance Payment and Solar Alternative Compliance Payment Levels for Energy Years 2009 and 2010 or Longer, and a Solar REC-Only Pilot.

On page 11 of the proceeding the following questions were posed by the Board:

1. What is the expected shortfall in solar PV capacity required to meet the RPS if the SACP levels for 2009 and 2010 remain at their current level of #300 per MWh?

2. What is the optimal SACP level required to ensure that sufficient solar PV capacity will be installed to meet the RPS goals at the least costs to the New Jersey ratepayer?

3. For what number of years should the SACP be established? Should it be established only for the Reporting Years of he next BGS auction timeframe of RY 2008-2010, longer, or shorter? What timeframe is reasonable?

4. Should the ACP and SACP in RY 2009 start at a higher level and decrease over subsequent Reporting Years, or should it start at a relatively low level, but higher than the RY 2008 level, and increase over multiple Reporting Years?

5. Can the SACP be structured to enable different SREC prices for solar electricity delivered by rebated and non-rebated solar facilities?

6. Should the SACP and the subsequent SREC have a life for payment to the renewable energy generator? Should the SREC continue only until the system is "paid for"? How long should that timeframe be?

7. What are the advantages and disadvantages to the Board's posting a multi-year schedule for SACP levels?

8. What are stakeholder's views regarding the Board's detailed economic analysis of the customer bill costs and the rate impacts of transitioning to a certificate-based financing system without rebates?

Appendix D:

RPS Benchmarking Tables

Table D-1. Summary of RPS Details and Systems Benefit Charge Funding by State[60]

	RPS Details						Renewable Energy SBC Funding	
State	**Ultimate RPS Target**	**Year Enacted**	**First Compliance Year**	**Resource Tiers and Special Resource Provisions**	**Cost Cap**	**Alternative Compliance Mechanisms / Penalties**	**Mils/kWh Collected**	**Million $ / Year Collected**
Arizona	15% by 2025	1996- Solar Portfolio Standard; 2001- Environmental Portfolio Standard	2001: multi-resource RPS	Distributed generation must account for 5% of renewables portfolio in 2007, increasing to 30% by 2011	SBC funds capped at $1.05/mo for res customers; $39/mo for non-res customers; and $117/mo for customers with load >3MW	If fail to comply with required amount of RECs, must file compliance plan to make up shortfall. Costs to make up shortfall are not recoverable.	0	0
California	20% by 2010-mandated, goal of 33% by 2020	2002	2003		SBC spending	Failure to comply with annual procurement targets automatically results in penalty of $55/MWh. Failure to comply with 20% goal will result in further penalties.	~2.7	150
Colorado	20% by 2020	2004	2007	Of renewables generated each year, 4% must come from solar electric. Of this amount, at least half must come from customer-sited systems.	Retail rate impact may not exceed 1% annually for all retail customers.			0
Connecticut	4% Class I and Class II by 2004; 10% by 2010; 4%	1998	2000[61]	Separate requirements for resources in Classes I, II, and III		Penalty = $55/MWh	1	20

[60] Sources for RPS details include Database of State Incentives for Renewable Energy (DSIRE) website (www.dsireusa.org); Union of Concerned Scientists Renewable Electricity Standards Toolkit (http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main); and Wiser, R. C. Namovicz, M. Gielecki, and R. Smith. "Renewables Portfolio Standards: A Factual Introduction to Experience from the United States." Lawrence Berkeley National Laboratory, April, 2007; and individual state public utility commission websites. Sources for SBC funding details include DSIRE website, and New York Public Service Commission Order, September, 2004.

[61] Original compliance year was 2000, though there were many loopholes (only applied to competitive suppliers and suppliers could defer compliance for up to two years). Revisions to the RPS law were passed in 2003 which held all suppliers to compliance and the first compliance year under the new rules was 2004.

	RPS Details						Renewable Energy SBC Funding	
State	Ultimate RPS Target	Year Enacted	First Compliance Year	Resource Tiers and Special Resource Provisions	Cost Cap	Alternative Compliance Mechanisms / Penalties	Mils/kWh Collected	Million $ / Year Collected
	Class III by 2010							
Delaware	10% by 2019	2005	2007			ACP = $25/MWh; If fail to comply for 2 years in a row,	0.089	0.75
District of Columbia	11% by 2022	2005	2007	Tier 1 and Tier II, plus 0.386% must come from solar by 2022		ACP = $25/MWh for Tier 1, $10/MWh for Tier 2, $300/MWh for solar.	2 mils max, 1 mil min, the majority of which has gone to low income and energy efficiency program spending	0.25 spent on renewables in 2005 and 2006
Hawaii	20% by 2020	2004[62]	2005	No	If PUC decides utility cannot meet RPS in cost-effective manner, can issue waiver.		0	0
Illinois	8% by 2013	2001	2007	75% of total portfolio must come from wind	RPS compliance costs may not increase retail electricity rates by more than 0.5% in any one year, or by more than 2% cumulatively.	Targets are goals only-compliance is voluntary	Varies by customer type (electric bill charges average $0.05/mo for res, $0.50/mo non res <10 MW demand, $37.50/mo non res >10MW; customers slso charged on gas bills based on gas demand categories)	5[63]

[62] An earlier version of Hawaii's RPS was past in 2001, but was unenforceable.

[63] $50 million spent on renewables over 1998-2007.

	RPS Details						Renewable Energy SBC Funding	
State	Ultimate RPS Target	Year Enacted	First Compliance Year	Resource Tiers and Special Resource Provisions	Cost Cap	Alternative Compliance Mechanisms / Penalties	Mils/kWh Collected	Million $ / Year Collected
Iowa	105 MW, or ~2% by 1999[64]	1983					0	0
Maine	30% total (new or existing) by 2000, 10% "new" by 2017	1997	2000			Utilities allowed to demonstrate compliance by averaging compliance over 2 or more years. Various penalties may occur for non-compliance including license revocation or fines (no determined amounts).	voluntary charges	(as of 11/05, Fund contained $100,000)
Maryland	7.5% by 2019	2004	2006	Tier I and Tier II. Plus solar receives 200% credit toward compliance. Through 2005, wind receives 120% credit toward compliance. For 2006-2008, wind receives 110% credit toward compliance. Through 2008 methane receives 110% credit toward compliance.		ACP = $20/MWh for Tier 1; $15/MWh for Tier II	0	0
Massachusetts	4% by 2009 (increasing by 1% per year after 2009)	1997	2003	None		ACP = $50/MWh when RPS first implemented. Rises annually with inflation and was 55.13 for 2006.	0.50	25

64 Percentage value is based on translation of capacity goal, found in LBNL, May, 2007.

	RPS Details						Renewable Energy SBC Funding	
State	Ultimate RPS Target	Year Enacted	First Compliance Year	Resource Tiers and Special Resource Provisions	Cost Cap	Alternative Compliance Mechanisms / Penalties	Mils/kWh Collected	Million $ / Year Collected
Minnesota	Xcel: 30% by 2020 requirement; 25% by 2025 "good faith objective" for all other utilities	1994	2005	25% of Xcel's supply must be generated by wind by 2025 (remaining 5% can come from other eligible sources).	PUC can change or delay standards it is deemed to be in the public interest.	A variety of penalties are possible for non-compliance either for Xcel or for other utilities with good faith goals. Penalty may not exceed amount required to construct resources or purchase credits.	Xcel Donations	16
Montana	15% by 2015	2005	2008	Special procurement requirements to stimulate rural economic development.	Yes	ACP = $10/MWh though can apply for short-term compliance waiver	Electric suppliers contribute 2.4% of 1995 revenue.	~3.7 ($14.9 M collected annually and divided across RE, EE, low income and R&D spending)
Nevada	20% by 2015	1997	2001	5% of portfolio must be from solar. PV resources receive a 2.4 multiplier for compliance purposes. PV systems installed at retail customer site where retail customer uses at least 50% of production from system annually can receive a 2.45 multiplier for compliance purposes. Savings from energy efficiency measures can be counted toward RPS compliance for up to 25% of a utility's required portfolio amount in any given year.			0	0

	RPS Details						Renewable Energy SBC Funding	
State	Ultimate RPS Target	Year Enacted	First Compliance Year	Resource Tiers and Special Resource Provisions	Cost Cap	Alternative Compliance Mechanisms / Penalties	Mils/kWh Collected	Million $ / Year Collected
New Jersey	22.5% by 2021	1999	2001	2.12% must come from solar by 2021		ACP = $50/MWh for Class I, $300/MWh for solar	Varies annually	~81 for 2007[65]
New Mexico	20% by 2020	2004[66]	2006	For compliance purposes: biomass, geothermal and landfill gas resources receive a multiplier of 2 for RPS compliance purposes; solar recieves a multiplier of 3.	Cap varies by technology: $0.049/kWh for wind and hydro; $0.06254/kWh for biomass and geothermal; $0.15/kWh for solar <10kW and $0.10/kWh for solar >10kW. Additional cost of the RPS to each customer may not exceed the lower of 1% of customer's annual electric charges or $49,000. Procurement limit criterion increases by 0.2% or $10,000 per year until January 1, 2011, when it remains fixed at the lower of 2% of the customer's annual electric charges or $99,000. After January 1, 2012, the commission may adjust limit for inflation.		0	0

[65] Figure does not include funds carried over from 2006.

[66] Public Regulation Commission approved an RPS in 2002. The rules were codified in 2004 through Senate Bill 43.

	RPS Details						Renewable Energy SBC Funding	
State	**Ultimate RPS Target**	**Year Enacted**	**First Compliance Year**	**Resource Tiers and Special Resource Provisions**	**Cost Cap**	**Alternative Compliance Mechanisms / Penalties**	**Mils/kWh Collected**	**Million $ / Year Collected**
New York	24% by 2013 (mandatory), plus 1% target from voluntary market	2004	2006	Main Tier (utility scale resources) and Customer-sited Tier. 2% of total requirement must come from Customer-sited Tier resources.	Yes		see notes for annual funding	RPS charge: ~47 projected RPS costs for 2007; New York Energy $mart Program: additional ~36 to be spent annually on R&D, including renewables infrastructure, from 2006-2011. Funding for customer-sited renewables projects supported through RPS charge funds.
Pennsylvania	18% during compliance year 2020-2021 (includes 8% Tier I and 10% Tier II)	2004	2007	0.5% must come from solar by 2020-2021 compliance year. Separate Tier I and Tier II categories for renewables eligibility. By 2021, 7% must come from Tier 1 and 10% from Tier II.	All reasonable and prudent costs are recoverable.	ACP = $45/MWh; for solar = "200% of average market value" of the solar credits sold during the reporting period.	Varies by utility territory	Multiple funds exist, created through settlements, and funding available varies by utility territory.
Rhode Island	16% by 2020	2004	2007			ACP = $50/MWh, adjusted annually for inflation	0.30	2.4
Texas	5,880 MW by 1/1/15, about 5% of state's electricity demand	1999	2002	Target: at least 500 MW from non-wind resources	The PUCT has the authority to cap the price of RECs	ACP = lesser of $50/MWh or 200% of value of RECs traded during compliance year.	0	0

	RPS Details						Renewable Energy SBC Funding	
State	**Ultimate RPS Target**	**Year Enacted**	**First Compliance Year**	**Resource Tiers and Special Resource Provisions**	**Cost Cap**	**Alternative Compliance Mechanisms / Penalties**	**Mils/kWh Collected**	**Million $ / Year Collected**
Vermont	Total incremental growth in demand from 2005-2012 must be met with new renewables (10% cap)- not mandatory	2005	In 2012, determine whether RPS becomes mandatory	Energy efficiency is an eligible resource.			0	0
Washington	15% by 2020 and cost effective conservation	2006	2012	Distributed generation recieves a multiplier of 2 for compliance purposes. Facilities developed after 12/31/05 using apprenticeship program receive multiplier of 1.2 for compliance purposes.	All prudently incurred costs can be passed along.	Penalty payment = $50/MWh	0	0
Wisconsin	10% by 2015	1998	2001	Hydropower receives special treatment			Varies by utility territory	Varies by utility through 6/30/07. Beginning 7/1/07, each utility is required to spend 1.2% of its annual operating revenue on efficiency and renewables.