ASSESSMENT OF THE NEW JERSEY RENEWABLE ENERGY MARKET

VOLUME II

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1 INTRODUCTION

This volume of the report includes detailed assessment reports for New Jersey's renewable energy market, and for each of the BPU's renewable energy programs, as well as a review of renewable energy market development strategies in place in other jurisdictions. Volume II also includes summaries of two reports the research team completed in support of the BPU's solar market transition efforts. This volume is intended for an audience interested in reviewing detailed data and discussion related to market and program performance, and policy and incentive strategies in place in other jurisdictions.

As was noted in Volume 1, for the purposes of maintaining consistency in program evaluation and monitoring methods, programs have been evaluated based on the amount of installed capacity that has *received incentive payment* as of the end of 2006. These projects are described as "completed" throughout the remainder of this report. In some cases, additional capacity has been installed, but has not received payment, and therefore is not included in the values presented in this assessment.

One project of particular note is the Jersey Atlantic Wind project. The 7.5 MW wind project was installed in 2005 with commitments to receive funding through both the CORE program (for the 2.635 MW of capacity serving on-site load), and from the REPGF program (for the 4.875 MW of capacity serving the electric grid). As of the end of 2006, the project had received its first payment under the REPGF program in 2006 ($173,759 of a total grant commitment of $1,696,000), but had not yet received payment from the CORE program. For the purposes of this assessment, 4.875 MW is counted toward the total amount of wind capacity "completed" in 2006 for the REPGF *program evaluation*, though the portion funded through the CORE program will not be counted as completed until 2007, when the project actually received payment from the program. However, because the project is by far the largest wind project installed to date in New Jersey, for the purposes of the *market-wide assessment*, the research team counted the full 7.5 MW of capacity from the project as "completed" in 2006 to provide a more accurate representation of the installed wind capacity which existed by the end of the assessment period.

2 MARKET LEVEL SUMMARY

2.1 Introduction

This section focuses on the effects that the BPU's programs and New Jersey's renewable energy policies are having on the New Jersey renewable energy market. To date, the key drivers of renewable energy market development in New Jersey have been the state's rebate and grant programs, federal tax incentives, and the RPS requirement to achieve 20% renewables supply by Energy Year 2021, including a 2.12% solar requirement. The RPS drives the market in that EDCs must procure enough RECs to meet their requirements, or pay an Alternative Compliance Payment. To the extent that SREC market values will increase under a new long-term SACP schedule, and rebate levels will decrease, the RPS requirements will become a much greater solar market driver relative to the rebates and incentives. The goal of this section is to provide feedback on the progress of the Board's programs and policies toward achieving goals for market development.

The section first provides a summary of the BPU's overall status toward achieving market-level goals approved by the Board. Next, market-level indicators are identified and discussed, followed by a discussion of market barriers. A discussion of the broad market effects of New Jersey's renewable energy programs and policies follows, and the section ends with a summary of key findings.

2.2 Summary of Goals and Achievements

2.2.1 BPU Goals Status Summary

The two goals the BPU has set forth for renewable energy market development, and the status toward these goals, are summarized in Table 2-1. For reference, as discussed in Volume 1, Section 2 of the report, New Jersey divides RPS eligible resources into two classes based on technology. Class I eligible resources include solar energy, wind energy, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels and certain other forms of biomass. Class II electricity resources include small hydropower (less than 30 MW) and resource recovery facilities. Within the Class I category, there is a separate requirement for solar resources.

Table 2-1. Summary of Market-Level Renewable Energy Development Goals

GOAL	STATUS[1]	ACHIEVED GOAL?
By 12/31/08, install 300 MW of Class I renewable energy generation capacity in New Jersey, of which a minimum of 90 MW should be from PV.	As of 12/31/06, 39 MW of Class I renewable energy capacity was funded through BPU programs; of which 27 MW was solar PV. A total of 115 MW of Class I resources were installed in the state including non-program-funded landfill gas.	An additional 185 MW of Class I renewable energy by 12/31/08; of which 63 MW must be solar PV and 122 MW must be non-solar resources. [2]
By 12/31/08, 6.5% of electricity in NJ should be provided by Class I or Class II renewables (defined in RPS), and 4% of Class I resources, including 120,000 MWh (90 MW) from solar.[3]	As of 12/31/06, NJ-sited renewable resources produced enough electricity to supply a total of 1.05% of the state's electricity load: Class I, 0.64% Class II 0.37% Solar, 0.03%	In 2006, Class I generation was 15% of what is needed to meet the BPU's 2008 goal, Class II generation was 14% of what is needed in 2008, and solar generation was 22% of what is needed in 2008.

2.3 Market Indicators

Market indicators (discussed in this section) and program performance indicators (addressed in Volume II, Section 2 of this report) are integrally related. Programs are designed to transform the market, and the effects of program implementation will manifest themselves in market trends and developments. In addition, market activity can be substantially affected by external factors (i.e., the existence of aggressive rebate programs in other states or countries could limit the availability of PV modules in New Jersey, and thus, slow the progress of PV installations). In developing new market indicators and assessing existing indicators, the focus was on broad market elements, including those beyond the control of the BPU programs.

Market indicators were developed to address the following questions:

- What size is the renewable energy market in New Jersey?
- How is the market changing?
- Is the market self-sustaining?

[1] This table excludes 1.5 MW of fuel cells and correlating generation. Fuel cells were excluded because those funded by BPU do not run on renewable fuels, which is a requirement for RPS eligibility, and the table only includes RPS eligible resources. This table also excludes the capacity associated with the existing 122,213 MWh of biomass resources.

[2] This assumes that the 300 MW goal pertains to all installed renewable energy capacity, whether or not a project received funding through a BPU program.

[3] These goals are specified in the BPU 2005-2008 and Beyond Strategic Plan.

An initial set of indicators were developed and measured for the purposes of completing this assessment. These indicators are listed below. Some additional indicators were identified that could not be measured for the purposes of this assessment due to lack of available data, but are recommended for measurement in the future. A full list of market indicators recommended for future measurement is included in Appendix B.

What size is the Renewable Energy Market in New Jersey?

1) Installed capacity by technology for Class I and Class II technologies

2) Generation by technology for Class I and Class II

3) Percent of electricity supplied to New Jersey residents and businesses that is from renewable sources

4) Amount of RECs generated by New Jersey generators for New Jersey RPS compliance

5) Number of renewable energy businesses serving New Jersey

How is the Market Changing?

6) Rate of change of installed RE capacity by technology for Class I and II

Is the Market Self-Sustaining?

7) Installed cost, by technology

8) Cost-effectiveness of RE technologies, by technology, for Classes I and II

9) Customer Return on Investment, by technology, for Classes I and II

10) New Jersey program expenditures

11) Amount of third-party investment support for the projects

12) Amount of local financing dedicated to RE systems

13) Willingness of participants to take on debt to facilitate installation

2.3.1 List of Indicators and Values

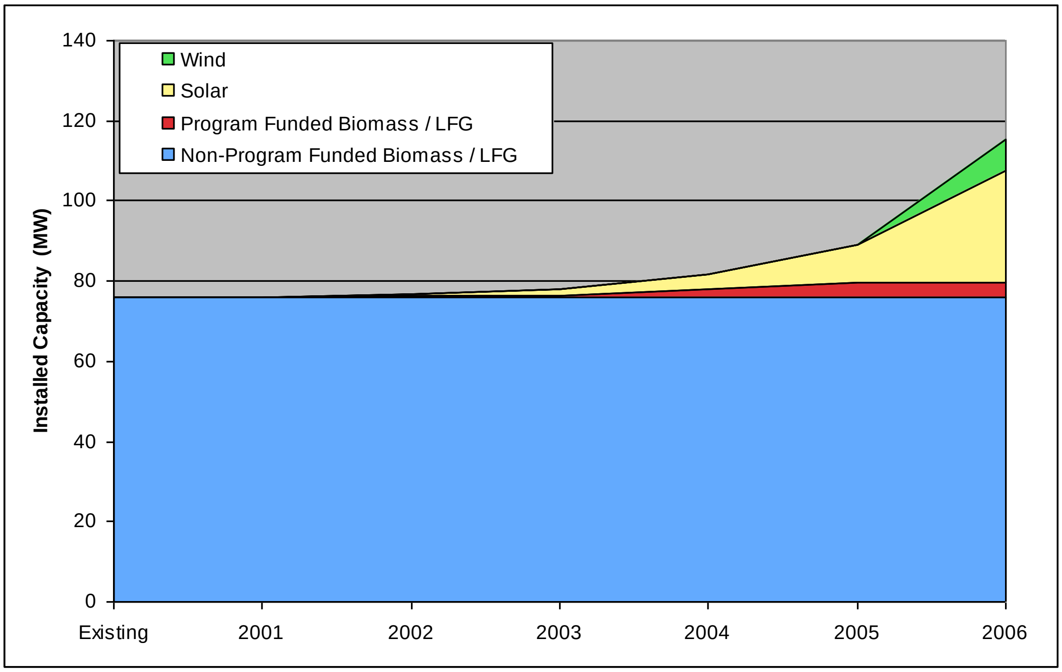
The indicators, the relationship to overall the BPU goals, and the results from the analysis are presented in this section.

Indicator #1: Installed Class I and Class II renewable energy capacity by technology

By December 31, 2008, the BPU's goal is for 300 MW of Class I renewable energy generation capacity to exist in New Jersey, of which a minimum of 90 MW should be PV.[4]

As shown in Table 2-1, as of December 31, 2006, 39.2 MW of Class I RE was completed (paid) through the BPU's programs, not including fuel cells.[5] Of this, 27.9 MW is PV. Seventy-six MW of landfill gas installed capacity existed prior to the BPU's program efforts getting underway. Because this existing landfill gas capacity makes up the majority of New Jersey's Class I renewable energy supply, it is included in Figure 2-1. However, only projects that had received payment from the BPU as of the end of 2006 are counted in this summary of New Jersey's Class I renewable energy supply. Including the existing landfill gas, the total Class I capacity as of December 31, 2006 was 115 MW. In order to achieve the 300 goal, New Jersey must add 185 MW of Class I renewable energy by December 31, 2008, of which 62.1 MW must be solar.

Figure 2-1. Class I Completed (Paid) Capacity as of December 31, 2006, plus Non-program-Funded Landfill Gas[6]



[4] "BPU 2005-2008 and Beyond Strategic Plan"

[5] This does not include fuel cells installed through the CORE program, as they are fueled with natural gas and, therefore, do not qualify as Class I sources. This number does include the 7.5 MW Community Energy / Jersey Atlantic wind project that had only received a small portion of its total grant payment as of the end of 2006 ($173,759 of a total $1,700,000 grant award).

[6] Sources: CORE and Renewable Energy Project Grants and Financing program data, and DEP files on non-program funded landfill gas. Note that only projects recorded as "completed" as of 12/31/06 are included.

Table 2-2. Class I Renewable Energy Capacity Completed by Year

Calendar Year (CY)	Solar	Wind	Biomass/LFG	Total
Existing	0.00	0.00	76.00	76.00
2001	0.009	0.00	0.00	0.01
2002	0.76	0.01	0.17	0.94
2003	0.76	0.02	0.15	0.93
2004	2.14	0.00	1.60	3.74
2005	5.53	0.01	1.85	7.39
2006	18.13	7.50	0.00	25.63
Total	27.30	7.54	79.77	**114.60**

Class II technology status is the second element of Indicator #1. RPS compliance data indicates that 314,191 MWh of Class II renewable energy was generated in New Jersey during the 2006 Reporting Year. Data on the installation dates and capacity of the Class II generators producing this electricity is unavailable. For the purposes of this report, the research team assumed that the renewable energy systems producing this electricity were installed prior to 2001.[7] Using estimated capacity factors for each technology type, the research team converted the Class II generation data to capacity estimates. It was estimated that Class II generators producing this electricity consist of 41 MW of Municipal Solid Waste (MSW) and 2 - 4 MW of small hydro (Table 2-3).

Table 2-3. Class II RE Capacity[8]

Class 2 Technologies Total		
Technology	**MW**	**Annual MWh**
MSW	41	305,135
Small Hydro	2 to 4	9,056
Total	43 to 45	314,191

Indicator #2: Generation by technology for Class I and II

During the 2006 Reporting Year, Class I generation from New Jersey sources was 543,160 MWh (2006 Class I RPS requirement was approximately 830,000 MWh).[9] Class II generation from New Jersey sources totaled 314,191 MWh during the 2006 Reporting Year (2006 Class II RPS requirement was

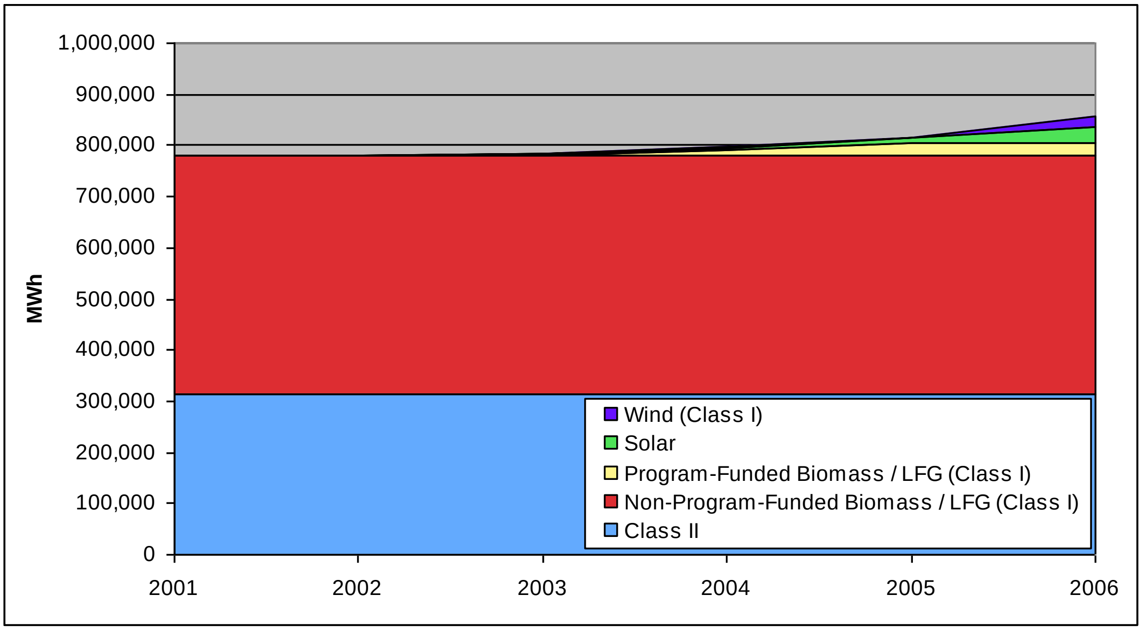
[7] The capacity values for these biomass generators were estimated based on capacity factor assumptions, and by accounting for the developers' generation estimates for BPU-funded systems.

[8] NJ BPU data, "RPS Comp 2006 Class I RECs.xls."

[9] Class I and Class II non-solar generation can come from both in-state and out-of-state resources. All suppliers complied with New Jersey's 2006 RPS requirements.

approximately 2.1 million MWh). Class I and Class II generation by technology and by year is presented in Figure 2-2.

Figure 2-2. Class I and Class II Annual Generation as of December 31, 2006



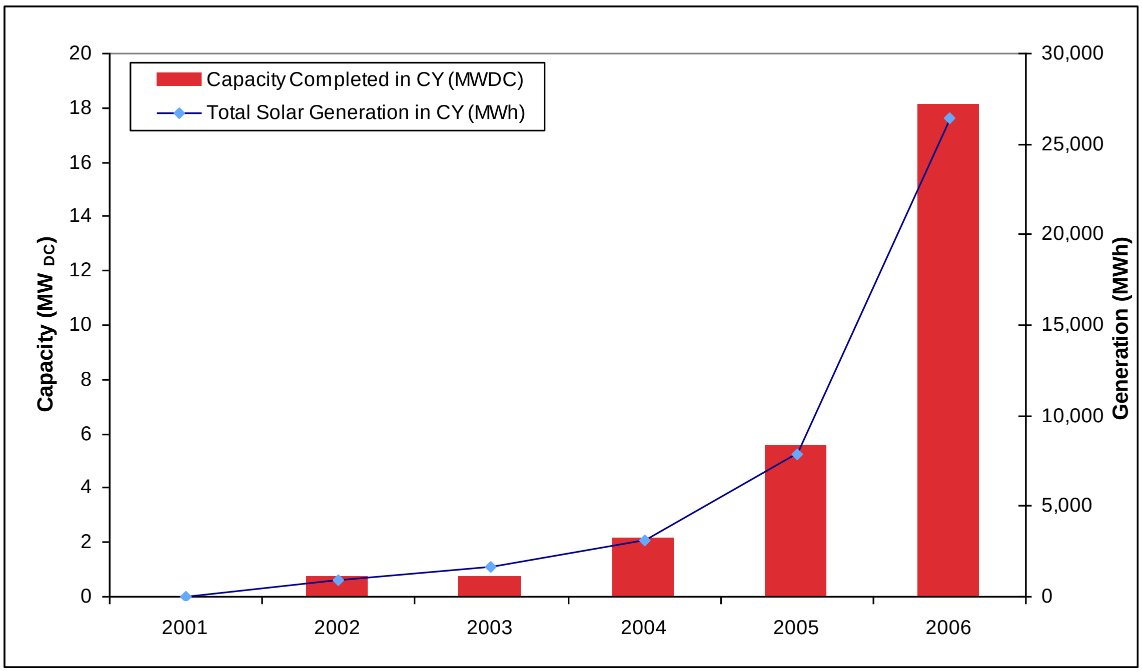
Solar generation for 2001 through mid-2003 was estimated using an assumed 13% capacity factor, and with an assumption that systems were running for the entire calendar year. In fact, systems were completed gradually throughout the year but insufficient data were available to account for this. For mid-2003 through 2005, the research team estimated generation using the Clean Power Estimator tool with detailed project data as inputs, including module orientation and tilt, and the number of month the system would have been operating during the calendar year. Due to the numerous systems with sub-optimal module orientation and/or tilt, the generation estimates for 2004 and 2005 are low compared to what one would expect from the same PV system capacity operating year-round and with optimal system design features (i.e., a 13% capacity factor). For 2006, the generation estimate is based on the value included in the 2006 4th Quarter (year to date) Clean Energy program report, as it is the understanding of the research team that this value was estimated using analytic methods similar to those used by the Summit Blue team for the mid-2003 through 2005 period.[10]

[10] The total installed capacity value in the 2006 report is 18.72 MW and 22,470 MWh of generation. However, the research team assumed this included the 0.6 MW fuel cell installed in 2006. Therefore, the values in the report were discounted accordingly to identify solar and fuel cell-specific values. Fuel cell assumed generation (based on 75% capacity factor) was subtracted from total generation value.

Table 2-4. Solar Capacity and Generation

Calendar Year (CY)	Capacity Completed in CY (MW_{DC})	Solar Generation from Systems Installed in CY (MWh)	Total Solar Generation in CY (MWh)
2001	0.01	11	11
2002	0.8	870	881
2003	0.8	792	1,673
2004	2.1	1,335	3,126
2005	5.5	3,260	7,894
2006	18.1	18,528	26,422
Total	27.3	24,796	40,007

Figure 2-3. Solar Incremental Capacity and Total Generation

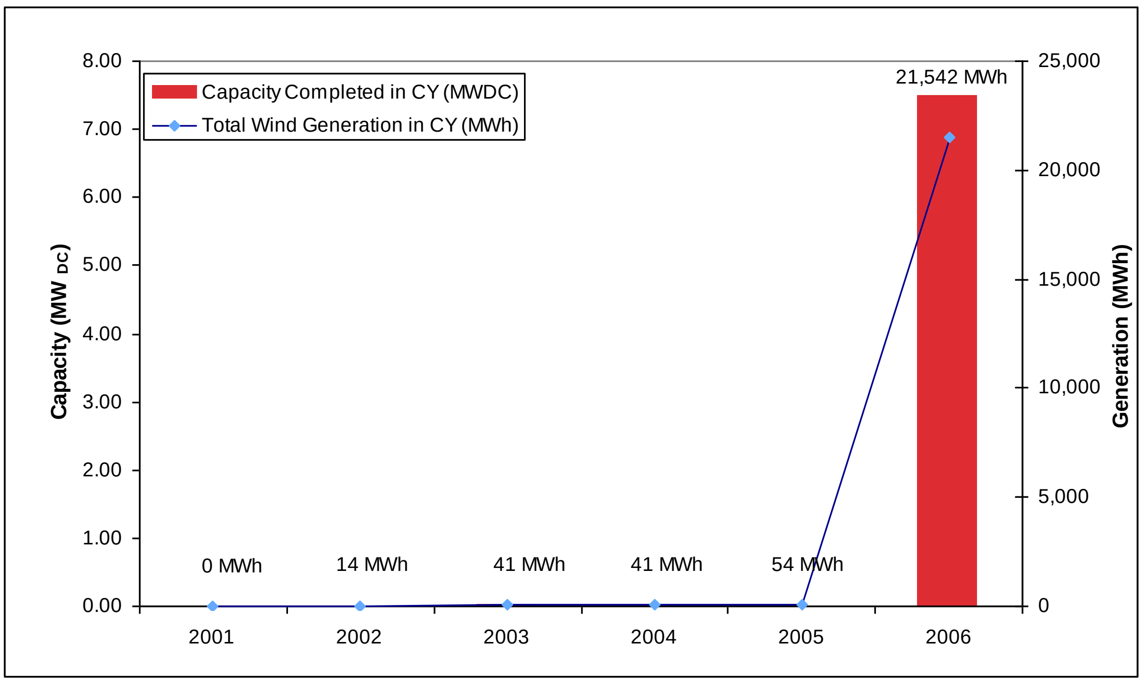


For wind systems, generation for all small systems (those completed from 2002 through 2005) is estimated using a 15% capacity factor which is consistent with the estimates used by the BPU, and is based on estimates provided by systems owners and/or manufacturers. For the 7.5 MW system completed (paid) in 2006, the generation value is taken from data provided to the BPU by the system owner.

Table 2-5. Completed (Paid) Wind Capacity and Generation[11]

Calendar Year (CY)	Capacity Completed in CY (MW_{DC})	Generation from Systems Completed In CY (MWh)	Total Wind Generation in CY (MWh)
2001	0.00	0	0
2002	0.01	14	14
2003	0.02	26	41
2004	0.00	0	41
2005	0.01	13	54
2006	7.50	21,488	21,542
Total	7.54	21,542	21,692

Figure 2-4. New Jersey Wind Incremental Capacity and Total Generation (Paid through December 31, 2006)



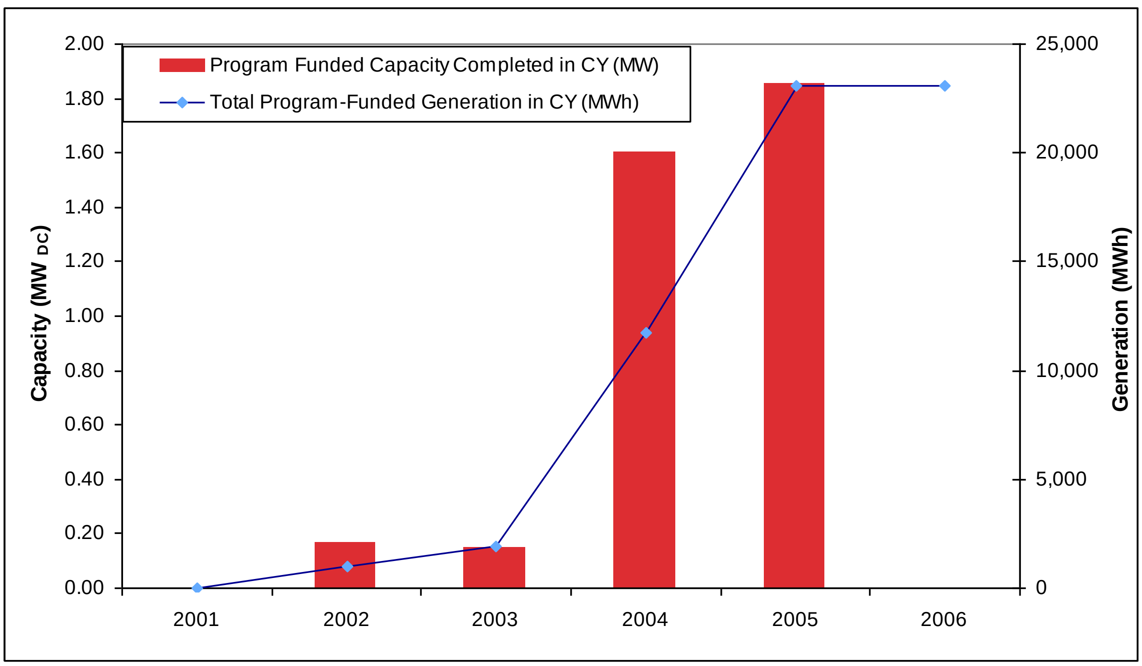
For biomass and landfill gas systems, capacity and generation is shown both for program-funded and non-program-funded systems since the latter value is so large. For solar and wind projects, to the knowledge of the research team there is no installed capacity in the state other than what has been funded by the BPU's programs.

[11] Sources: BPU program records for CORE and Renewable Energy Project Grants and Financing programs.

Table 2-6. Biomass/LFG Capacity and Generation[12]

Calendar Year (CY)	Program Funded Capacity Completed in CY (MW_{DC})	Total program-Funded Generation in CY (MWh)	Non-program Funded Capacity Available in CY (MW)	Total Non-program Funded Generation in CY (MWh)	Total Biomass / LFG Capacity in CY (MW_{DC})	Total Biomass / LFG Generation in CY (MWh)
2001	0.00	0	76.00	466,032	76.00	466,032
2002	0.17	1,024	76.00	466,032	76.17	467,056
2003	0.15	1,944	76.00	466,032	76.15	467,976
2004	1.60	11,755	76.00	466,032	77.60	477,787
2005	1.85	23,099	76.00	466,032	77.85	489,131
2006	0.00	23,099	76.00	466,032	76.00	489,131
Total	3.77	60,921.42	76.00	2,796,192	79.77	2,857,113

Figure 2-5. New Jersey Biomass/Landfill Gas Incremental Capacity Additions and Total Generation by Year



Three fuel cells had been installed under the CORE program as of the end of 2006. These fuel cells are all fueled by natural gas, and thus, are not counted as Class I resources. However, a summary of fuel cell

[12] A capacity factor of 70% was assumed for biomass / LFG projects. Because of the size of the table (showing both program-funded and non-program-funded values), estimates for generation from program-funded systems installed in each year are not shown separately in the table.

installed capacity and generation is provided in Table 2-7. A capacity factor of 75% was used to estimate generation.

Table 2-7. Fuel Cell Capacity and Generation[13]

Calendar Year (CY)	Fuel Cell Capacity Completed in CY (MW_{DC})	Generation from Capacity Completed in CY (MWh)	Total Fuel Cell Generation in CY (MWh)
2001	0.00	0	0.00
2002	0.20	1,314	1,314.00
2003	0.20	1,314	2,628.00
2004	0.50	3,285	5,913.00
2005	0.00	0	5,913.00
2006	0.60	3,942	9,855.00
Total	1.50	9,855	25,623.00

Indicator #3: Percent of electricity supplied to New Jersey residents and businesses that is from renewable sources.

The purpose of this indicator is to track New Jersey's compliance with RPS requirements, and progress toward achieving separate BPU renewable energy generation goals. The 2008 RPS requirements are 2.924% Class I (estimated to be 2.6 million MWh), 2.5% Class II (estimated to be 2.2 million MWh), and 0.082% solar (estimated to be 72,000 MWh). A BPU goal for the end of 2008 is for 4 percent (estimated to be 3.4 million MWh) of New Jersey's electricity to be supplied by Class I renewable energy, including 120,000 MWh (90 MW) from solar, and for 2.5 percent (estimated to be 2.5 million MWh) of the state's electricity to be supplied by Class II generation.[14]

The BPU's 2008 goals exceed the amount of renewable energy generation necessary to meet New Jersey's 2008 RPS requirements. For example, the BPU's PV goal of 120,000 MWh (90MW) is higher than the estimated 2008 solar RPS requirement. Based on the solar RPS goal (0.082% of retail sales in 2008) and the projected 2008 New Jersey electricity sales (87,887,103 MWh) the estimated 2008 solar RPS requirement is approximately 71,800 MWh, which would require about 63 MW of solar installed capacity.[15] Thus, only about 60% of the BPU's 2008 goal for solar generation would need to be met in order to fulfill the projected 2008 solar RPS requirement.

It should be noted that the RPS Reporting Year is from June first to May 31, and is named for the year in which it ends (i.e. the 2008 Reporting Year is from June 1, 2007 to May 31, 2008). Therefore, there are still seven calendar months in 2008 that are not included in the 2008 Reporting Year.

[13] Sources: CORE program data.

[14] Source: "BPU 2005-2008 and Beyond Strategic Plan."

[15] Based on BPU data for 2007 Reporting Year consumption (86,588,279 MWh), and an assumed annual growth rate of 1.5%. Assumes 13% solar capacity factor.

Table 2-8 presents a summary comparison of the BPU and RPS goals. Values that are bolded are those that are specifically defined by the BPU or by the RPS rules. Other values are calculated based on consumption, load growth, and technology capacity factor assumptions defined in the Methodology section. The RPS and the BPU targets summarized here are referenced throughout this market level assessment. BPU goals referenced here are based on goals specified in the BPU 2005-2008 and Beyond Strategic Plan. RPS requirements are based on those specified in the Renewable Portfolio Standards (RPS) Rules Adoption, April 2006 (N.J.A.C. 14:8-2). Those figures shown in bold type are specifically referenced in the Strategic Plan or the RPS rules. Figures that are not in bold print are calculated using percentage goals / requirements and 2007 Reporting Year sales data, adjusted annually assuming a 1.5% annual growth rate.[16]

Table 2-8. Summary of 2008 BPU Target and RPS Requirement for 2008 Reporting Year

BPU / RPS Targets	Percentage Requirement	Generation (MWh)	Capacity (MW)
BPU Targets			
Class I	**4%**	3,515,000	**300**
Class II	**2.5%**	2,197,000	N/A
PV	N/A	**120,000**	**90**
Total RE	**6.5%**	5,832,000	N/A
RPS Requirement			
Class I	**2.924%**	2,570,000	N/A
Class II	**2.5%**	2,197,000	N/A
PV	**0.0817%**	71,800	63
Total RE	**5.51%**	**4,838,800**	N/A

Table 2-9 presents a summary of New Jersey RPS requirements and generation from New Jersey renewable energy sources. Note that requirements are presented by RPS Reporting Year and generation is presented by calendar year (CY) due to the form in which data is available. As shown in the table, during the 2006 calendar year, Class I sources in New Jersey generated 543,160 MWh (0.64% of 2006 Reporting Year electricity use), and Class II sources generated 314,191 MWh (0.37% of 2006 Reporting Year electricity use), and solar sources are estimated to have generated 26,422 MWh (0.04% of 2006 Reporting Year electricity use). These generation values add up to an amount equal to 1.05% of New Jersey's total electricity usage during the 2006 Reporting Year.[17] With electricity demand growing at an assumed rate of 1.5% per year, electricity consumption during the 2008 Reporting Year will be 87,887,103 MWh. To achieve the BPU's renewable energy generation goals for calendar year 2008, 3,515,000 MWh will need to be supplied to New Jersey from Class I sources, 2,197,000 MWh will need to be supplied from Class II sources, and 120,000 MWh will need to be supplied from in-state solar sources. In 2006, Class I

[16] 2007 EY sales equaled 86,588,279 MWh based on data provided by BPU in October 2007.

[17] Note that this solar % is different than the solar % referenced above, because here the % is calculated based on the total New Jersey load for 2006, rather than the discounted load actually used for solar RPS compliance.

generation was 15% of what is needed to meet the BPU's 2008 goal, Class II generation was 14% of what is needed in 2008, and solar generation was 22% of what is needed in 2008.

Table 2-9. New Jersey RPS Supply and Demand[18]

Reporting Year	Annual Electricity Sales (MWh)	Class I RPS Req. (%)	Class I RPS Req. (MWh)	NJ Class I Gen. CY (MWh)	Class II RPS Req. (%)	Class II RPS Req. (MWh)	NJ Class II Gen. CY (MWh)	Solar RPS Req. (%)	Solar RPS Req. (MWh)
2005	77,593,167	0.740%	574,189	497,079	2.50%	1,939,829	314,191	0.010%	7,759
2006	84,353,329	0.983%	833,730	537,095	2.50%	2,108,833	314,191	0.017%	10,450
2007	86,588,279	2.037%	1,763,803		2.50%	2,164,707		0.039%	34,029
2008	87,887,103	2.924%	2,569,819		2.50%	2,197,178		0.082%	71,804
2009	89,205,410	3.840%	3,425,488		2.50%	2,230,135		0.160%	142,729
2010	90,543,491	4.685%	4,241,963		2.50%	2,263,587		0.221%	200,101
2011	91,901,643	5.492%	5,047,238		2.50%	2,297,541		0.305%	280,300
2012	93,280,168	6.320%	5,895,307		2.50%	2,332,004		0.394%	367,524
2013	94,679,370	7.143%	6,762,947		2.50%	2,366,984		0.497%	470,556
2014	96,099,561	7.977%	7,665,862		2.50%	2,402,489		0.621%	596,778
2015	97,541,054	8.807%	8,590,441		2.50%	2,438,526		0.765%	746,189
2016	99,004,170	9.649%	9,552,912		2.50%	2,475,104		0.928%	918,759
2017	100,489,233	10.485%	10,536,296		2.50%	2,512,231		1.118%	1,123,470
2018	101,996,571	12.325%	12,571,077		2.50%	2,549,914		1.333%	1,359,614
2019	103,526,520	14.175%	14,674,884		2.50%	2,588,163		1.572%	1,627,437
2020	105,079,418	16.029%	16,843,180		2.50%	2,626,985		1.836%	1,929,258
2021	106,655,609	17.880%	19,070,023		2.50%	2,666,390		2.120%	2,261,099

The Class I requirement for Reporting Year 2006 (ending May 31, 2006) was 833,750 MWh, or 0.983% of electricity supply. New Jersey's electricity suppliers retired, 847,857 Class I RECs, and made 19 ACPs to achieve RPS compliance for Energy Year 2006.[19] Compliance was achieved in Energy Year 2005 as well. Therefore, New Jersey's electricity suppliers have been able to meet the Class I RPS requirements to date. Results have also been positive for solar generation. In 2006 solar energy systems in New Jersey generated 26,421 MWh, or 0.043% of the state's electricity supply.[20]

Looking ahead to the future, in order to meet the 2008 solar RPS requirement, New Jersey would need to generate roughly 73,000 MWh of electricity from PV. This would require a 2008 installed PV capacity of about 64 MW, or 36 MW of new solar capacity. Since the amount of PV capacity added in 2006 was 18.7 MW, meeting the RPS PV requirement in Reporting Year 2008 seems quite reasonable if New Jersey can moderately increase its PV installation rate.

[18] Based on BPU data for Reporting Year 2006 and preliminary sales data from PJM-EIS for 2007 electricity usage. Assumed annual growth rate for electricity use is 1.5%. CORE and REPGF program data, BPU RPS compliance data, and DEP landfill gas data were used to estimate actual generation by New Jersey sources.

[19] Source: BPU 2006 RPS Class I compliance report.

[20] The electricity load used as the basis for 2006 RPS compliance differed for Class 1 and solar resources. A portion of load was subtracted for the purposes or solar RPS compliance due to the fact that LSEs had already entered into BGS auction agreements when the solar RPS went into effect in Reporting Year 2005.

However, the situation for all (Class I and Class II) renewables generated within New Jersey is not as promising. The 2008 RPS requirement is 2.92% Class I and 2.5% Class II. Based on load growth projections, New Jersey will need 2.6 million MWh of Class I generation and 2.2 million MWh of Class II generation in 2008 to comply with the RPS.[21] Renewable generation within New Jersey in 2006 was only approximately 0.5 million MWh. Therefore, if New Jersey electricity suppliers intended to meet the 2008 RPS renewable requirement with renewable energy generated in New Jersey, an additional 4.5 million MWh of generation would need to be generated from in-state qualified sources, which implies a rather unlikely increase in the rate of growth of renewable capacity in the state. Fortunately, New Jersey's suppliers can purchase RECs from outside New Jersey to satisfy their Class I (non-solar) and Class II requirements.

Table 2-10 shows a forecast for RPS demand and New Jersey Class I and Class II eligible supply available throughout the PJM region. These data show that there should be a sufficient supply of Class I renewable energy generation within the PJM territory to meet all PJM RPS requirements through 2008.

[21] 2008 estimated sales are based on preliminary sales data from PJM-EIS for 2007 electricity usage. Assumed annual growth rate for electricity use is 1.5%. .

Table 2-10. PJM RPS Class I Supply and Demand[22]

Projected Demand					
	Reporting Year Requirement	**2006**	**2007**	**2008**	**2009**
	Class I New Jersey (MWh)	833,730	1,763,803	2,569,819	3,425,488
	Other PJM RPS (MWh)		148,777	414,151	859,518
	Total RPS Demand (MWh)	833,730	1,912,580	2,983,970	4,148,006
Available PJM Supply as of 2005					
Capacity (MW)	Landfill Gas	378	378	378	378
	Biomass (NJ Qual)	-	-	-	-
	Wind	364	364	364	364
	Offshore Wind	-	-	-	-
Capacity factor	Landfill Gas	85%	85%	85%	85%
	Biomass (NJ Qual)	85%	85%	85%	85%
	Wind	30%	30%	30%	30%
	Offshore Wind	32%	32%	32%	32%
Total Generation (MWh)	Landfill Gas	2,817,566	2,817,566	2,817,566	2,817,566
	Biomass (NJ Qual)	-	-	-	-
	Wind	957,512	957,512	957,512	957,512
	Offshore Wind	-	-	-	-
	Total NJ Class I RPS Eligible Generation in PJM Region as of 12/31/06	3,775,078	3,775,078	3,775,078	3,775,078

[22] New Jersey RPS required Class I supply is based on current data for 2006 and 2007 reporting year energy consumption. All other values based on PJM RPS projections provided by BPU. It is the research team's understanding that the PJM projections were current as of the end of 2005. Therefore, any changes in RPS requirements in PJM states since then are not reflected in the table.

Indicator #4: Amount of RECs generated by New Jersey generators used for New Jersey RPS compliance

The PJM Environmental Information Services (PJM EIS) launched the Generation Attribute Tracking System (GATS) in October 2005 to provide environmental and emissions attributes-reporting tracking services for states in the PJM region. According to GATS data, of the 833,750 RECs required for Class I RPS compliance in New Jersey, 171,565 (21%) were generated in-state.[23] The New Jersey RPS Class II requirement was 2,047,420 RECs based on an RPS requirement of 2.5%. Of the 2,047,420 RECs used for Class II compliance, 314,191 RECs (15%) were generated in state.[24]

Indicator #5: Number of renewable energy businesses serving New Jersey

A summary of businesses serving the New Jersey renewable energy market is provided in Table 2-11.

Table 2-11. Market Participants Registered with BPU[25]

Market Participant	Number
REC Brokers	43
REC Aggregators	58
Suppliers / Load Serving Entities (LSEs)	36
Solar Installers	100
Fuel Cell Installers	14
Biomass Installers	6
Wind Installers	22

Indicator #6: Rate of change of installed capacity by technology

For each technology, a compound annual growth rate (CAGR) was calculated for the period 2002 through 2006. A base year of 2002 was used because so little installed capacity existed in 2001 (zero for all but solar), the CAGR using 2001 as the base year was either not representative or could not be calculated.[26] Solar has grown at a compound annual growth rate (CAGR) of 145% since 2002 demonstrating by far the highest growth rate of all Class I renewable energy sources[wind growth is 412%, which is greater than solar]. Wind has grown at a CAGR of 412% percent;[27] biomass and LFG have grown at a CAGR of 118%. Based on available data, it does not appear that Class II renewables have grown since 2001. The existing MSW and small hydro contributed 314,191 MWh of renewable energy annually.

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23 NJ Solar Market Update, January 2007.

24 BPU 2006 RPS compliance data.

25 Source: BPU Solar Market Update, April, 2007, and BPU registered vendor data.

26 Using 2001 as the base year, the CAGR for solar is 389%.

27 This is largely due to the 7.5 MW wind turbine installed in 2006. CAGR for the period 2002-2005 was 55%.

Table 2-12. Compound Annual Growth Rates by Technology

Technology	Compound Annual Growth Rate of Installed Capacity (2002-2006)
Solar	145%
Wind	412%
Biomass / LFG	118%
Fuel Cells	68%

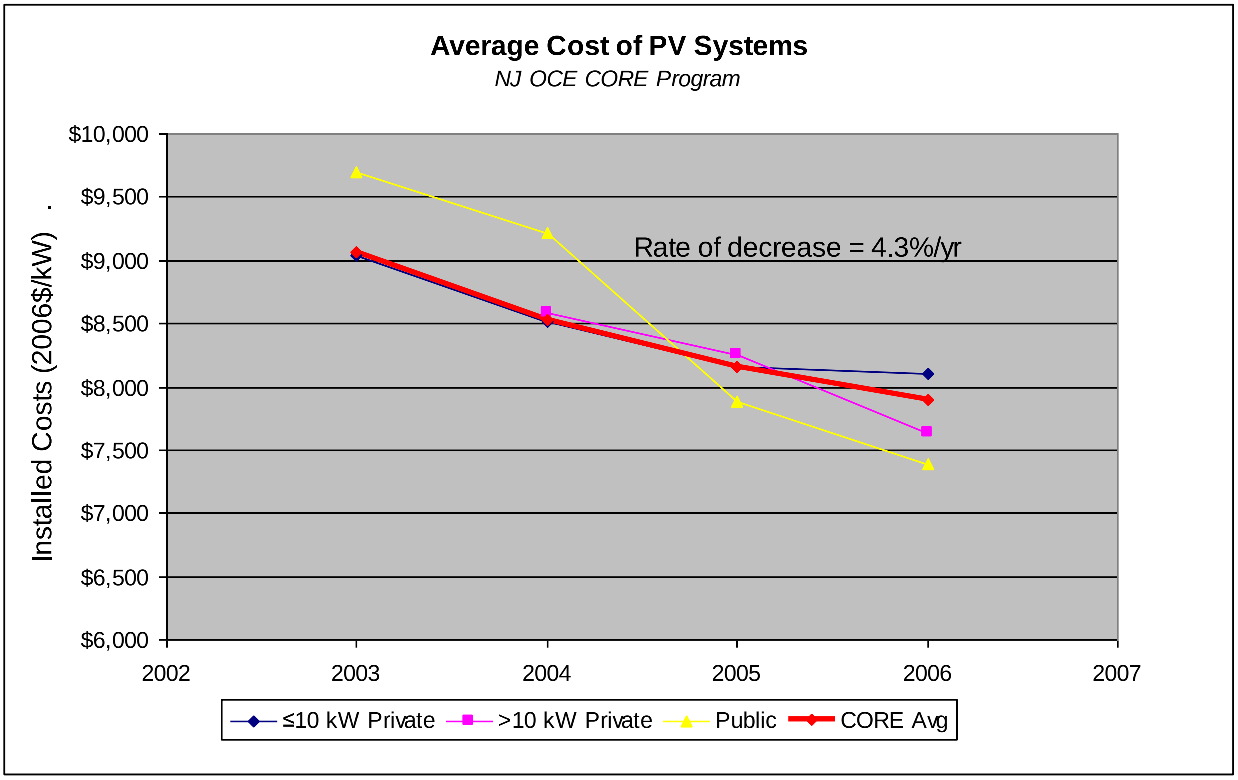
Indicator #7: Installed Cost, by technology

Because so few projects had been funded under the REPGF program through the end of 2006, this analysis is based on CORE-funded projects only. Solar installed costs have decreased on average by 4% per year since the start of the CORE program (Table 2-13 and Figure 2-6).

Table 2-13. Average Cost of PV System Installed Under CORE Program (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 2-6. Average Cost of PV System in CORE Program (2006$/kW)



Installed costs for 2006 across the full range of technologies are provided in Table 2-14 below.

Table 2-14. Installed Costs by Technology (2006)

Technology	Installed Costs ($/kW, 2006)
Solar	$7,901
Wind	$7,172
Biomass / landfill gas	$3,232
(fuel cells)	$6,193

Indicator #8: Renewable energy cost-effectiveness by technology

Indicator #9: Internal Rate of Return of renewable energy systems

Because "cost effectiveness" encompasses a range of possible financial metrics, and because a number of assumptions were used in the analysis, this section includes a review of a range of project financial considerations. A complete discussion of the assumptions used for this analysis is included in Volume 1, Section 3.

Definition of Cost Effectiveness and its Relationship to Project Type and Project Finance

The wind systems analyzed here span a broad range of sizes and potential applications, and the cost effectiveness requirements of the owners vary with the type of system and type of ownership, among other factors. For example, small 10 kW systems are potentially available to farmers or small commercial operations. These systems could be net-metered and take advantage of the value of offsetting retail electric rates. At this size, there is probably a range of sophistication among the users with some who understand the concept of internal rate of return (IRR) and others who rely on simple payback criteria as their figure of merit.

For this type of situation the hurdle rates (i.e., the IRR, or payback, that a project must beat in order to justify the capital investment) vary by industry and motivation of the owners. However, the Summit Blue team's assumption is that they will typically require IRRs in the range of 6-12%. Because net metering ensures an off-take for the power, that part of the revenue is relatively risk-free. However, the loan amounts for systems of this size, perhaps $10,000 to $30,000, are probably difficult to debt finance, since they are not large enough to support typical non-recourse ("project") lending, which is backed only by the turbine and its future output.

By contrast, larger wind systems today are typically developed by independent power producers who are familiar with more complex financing strategies. Financing for these plants is usually non-recourse or project finance, where the capital cost is typically made up of various branches of debt and equity. Many of these structures now feature ownership "flips" where the relative positions in the cash flow chain (i.e. who gets the first rights to cash left after expenses and debt service) change at one or more points in the life of the plant, depending on details of the PTC and the loan structure.

In interviews, financiers and developers working in this field stressed that the hurdle rate for their projects was highly dependent on how risky the revenues were. For a situation with a long-term (10 year or longer) creditworthy power purchase agreement (PPA) and off-take agreement for the RECs, their hurdle rate could be as low as 6-8%. However, if they were trying to build a "merchant" plant—one that needed to sell these outputs into a competitive market—they would need IRRs in the mid-teens or above, if they could be lured into participating at all.

The Summit Blue team chose the IRR as the metric to use to characterize cost-effectiveness as opposed to the (usually annual) ROI because it provides similar financial information and more clearly indicates the return over the lifetime of a system for complex project ownership structures that include more than one type of ownership. Only three percent of CORE program survey participants used the percentage return on investment (ROI) to determine whether their renewable energy project met the payback requirements that they needed to go forward with the project, indicating that ROI has not historically been the most important factor to consumers installing renewable energy systems in New Jersey. Eighty-nine percent of the CORE program survey participants used simple payback as the economic requirement to determine whether or not they would go ahead with their renewable energy system investment.

Discussion of technology-specific cost effectiveness factors is provided below. For details on the research team's analysis of recommended incentive levels by technology market sector, see Volume 1, Section 5.

Solar

Residential Solar

Residential solar projects are currently highly dependent on the BPU incentives. A 2004 study by Navigant Consulting found that residential installed PV systems cost about $8,500/kW$_{AC}$ in New Jersey, and that solar resources in New Jersey were moderate to low, providing an effective capacity factor of 13-14%.[28] CORE program data show that PV installed costs in New Jersey were approximately $8,100 kW for ≤10 kW private projects, and approximately $7,600/kW for ≥10kW private projects in 2006. New Jersey's installed solar costs are roughly comparable to other states. California's installed residential solar costs in 2004 dollars were less than $9,000/kW$_{AC,}$[29] although the capacity factor for solar in California is higher than New Jersey (approximately 18% as opposed to 13%).[30]

The current rebate level for PV offered under the CORE program was $3.80/W rebate for systems up to 10kW as of August 2007. Without the incentive, the levelized energy cost for a residential PV system is approximately 38.1 cents/kWh, and with the New Jersey incentive, the levelized cost is approximately 12.5 cents/kWh.

Although PV has advantages over other renewable energy technologies (no real estate costs if the PV is sited on building roof, output roughly coincident with peak air conditioning demand, and little to no operation and maintenance costs because the panels do not have moving parts), the upfront capital required (per installed kW) is still considerably higher than for fossil fuel or other renewable power sources.

CORE program rebate levels were designed with the goal of providing projects with a 10-year simple payback.[31] Under this program structure, up-front rebates reduce the risks to project investors, and thus, investors may be willing to accept lower levels of ROI or longer loan terms. Based on feedback from the solar industry and members of the financial community, the 10-year payback threshold is insufficient to stimulate the level of development necessary to meet RPS goals in a post-rebate environment.

To date, CORE program participants have been wealthier and more educated than average New Jersey residents. Even given that, 56% of the CORE program survey participants reported they would not have gone forward with their PV installation if the rebate amount had been even 25% less than it was. This strongly indicates that if the BPU were to reduce the CORE program rebate, or comparable value provided by some other form of incentive, it would significantly reduce the level of participation in the program, and the ability of New Jersey to meet its solar RPS requirements. Additionally, 59% of CORE survey respondents expressed significant concern about product cost-effectiveness before installing the renewable energy system. The research team did not conduct a detailed analysis of the likely number of "early adopters" in New Jersey. However, it is reasonable to assume that a broader cross-section of the New Jersey population will wish to take advantage of on-site power production opportunities as electricity prices and levels of renewable energy awareness both rise. When less wealthy residents and businesses seek to participate in the solar market in greater numbers, cost-effectiveness will likely become a more significant issue.

[28] New Jersey Renewable Energy Market Assessment, Navigant Consulting, Inc. August 2, 2004.

[29] Wiser, Ryan and Bolinger, Mark. "Projecting the Impact of Solar Portfolio Standards on Solar Installations." Prepared for the CEC, January 20, 2005. http://eetd.lbl.gov/ea/ems/reports/59282-es.pdf.

[30] Wiser, Ryan and Bolinger, Mark. "Projecting the Impact of Solar Portfolio Standards on Solar Installations." Prepared for the CEC, January 20, 2005. http://eetd.lbl.gov/ea/ems/reports/59282-es.pdf.

[31] Or roughly a 9-10% IRR for a 20-year system life.

Commercial Solar

Developers who were interviewed indicated that they considered net present value of the New Jersey rebate, long-term SREC values, federal tax incentives, financing mechanisms and the full lifetime (30-40 years)[32] for average projects when calculating the levelized costs of PV installations. As with the residential systems, the cost-effectiveness of commercial solar is also heavily dependent on available incentives.

There were diverse opinions among the developers and manufacturers interviewed regarding the effectiveness of the New Jersey incentive for solar. For example, some developers believe that the current New Jersey solar incentive is not worth anything because a) it has been unavailable due to budget constraints; and b) it does not actually reduce the developer's out-of-pocket expenses. Under the current system the developer or owner must pay for the solar components and installation, and then must wait for New Jersey to process their application and pay the rebate. In one example provided by a developer, $30,000 in interest accrued while the developer waited for a rebate from the BPU. This clearly reduces the value and cost-effectiveness of the New Jersey rebate. Conversely, other developers interviewed confirmed that the incentives offered by New Jersey have definitely had a positive impact on their business.

Because commercial projects can take advantage of the substantial corporate federal tax incentives, they are more cost-effective than residential and public PV projects. However, commercial projects are still heavily dependent on financial incentives.

Public Solar

Public solar projects only made up two percent of the overall number of CORE funded PV projects from 2003 through 2006. The rate of decrease in costs for the few public projects that have been completed is substantial. Installed costs for public projects were $9,600/kW in 2003, and they dropped to $7,400/kW in 2006. However, because these costs represent such a small number of projects, it is not clear that this cost differential between public and private projects will continue. Because publicly-owned projects cannot take advantage of any tax incentives, they are less cost-effective than residential and commercial systems.

Solar Cost Effectiveness

For solar systems, the ratepayer impact model was used to determine the incentive needed to produce an IRR of 12%.[33] The table below shows the recommended incentive levels for different technology-market sectors. The values reflect the continued significant need for a rebate for residential systems and a lesser need for rebates for larger systems. It is assumed that all solar projects will receive SREC income in addition to these rebates.

[32] This was the average estimated project lifetime provided by developers interviewed as part of the market assessment.

[33] The ratepayer impact model is the pro forma-based Excel workbook used to estimate ratepayer impacts of various scenarios for a market-based solar incentive structure.

Wind

For all sizes of wind projects, the New Jersey incentive reduces upfront capital, the federal PTC increases project revenues for the first 10 years, and the Modified Accelerated Cost Recovery System (MACRS) reduces the projects' taxable income for the first six years. These are clearly valuable benefits to wind developers. However, it appears that these benefits are likely to be most beneficial to larger systems that are more likely to have equity investors who possess a large enough tax appetite to fully capture the value of Federal tax incentives, the financial sophistication to maximize these benefits, and the flexibility (as opposed to a home-owner or business) to locate their plant in a good wind regime.

It should be noted that the pro forma model used for this analysis did not take advantage of the various "flip" ownership structures or "balloon" type debt structures that are frequently used in financing larger plants today. As one result of this, the debt coverage ratio ("DCR," which measures how much cash the project has in any period to meet the debt service) may not be consistent with industry standards over the term of the loan. Nonetheless, the analysis indicates that if locations with suitable resource can be found either on- or off-shore, it should be possible to develop larger wind farms in New Jersey that will provide reasonable rates of return to investors.

Assessment of cost-effectiveness of wind plants in New Jersey is difficult because of the paucity of data available on systems installed to date. However, the Summit Blue team used the publicly available data in combination with some representative industry values to assess the cost-effectiveness of wind projects in the state. The Summit Blue team analyzed three potential system types that included a range of sizes, from a small on-site plant up to a large plant located offshore. A feature that will be critical in evaluating the cost effectiveness of any system is the capacity factor, which measures how much annual energy a system of a given size will produce.[34] For wind systems, the capacity factor is driven almost entirely by how strong and how frequently the wind blows on a particular site. For this reason, the financial benefits of a wind system are very sensitive to the assumptions about capacity factor.

There is a marked difference between the capacity factors provided to the BPU by wind project owners participating in the CORE program (15% capacity), and those that turbines should be able to achieve under favorable wind conditions (~30% capacity factor depending on turbine technology and location). However, as noted above, In this analysis, we have used the capacity factor reported by the project developer or by independent studies wherever possible.

For the medium sized wind system analysis, it is assumed that a purchase agreement with some creditworthy entity in New Jersey is in place for both power and RECs with a loan term of at least seven years. The capacity factor for the medium-sized wind systems is assumed to be 29%. This value was taken from publicly-available information for the 7.5 MW Community Energy / Jersey-Atlantic system in

[34] A capacity factor of 1.0 would mean that the system was producing at full capacity every hour of the year. Large central fossil-fuel generators frequently have capacity factors in the 90+% range, while PV systems are usually down in the 10-20% range.

southern New Jersey,[35] and is notably higher than the value of 15% provided to the BPU by smaller wind project owners.[36]

For the large (offshore) system, it was assumed that there was a long-term purchase agreement in place for both the power sales (at $0.05/kWh) and RECs. However, Wolfe, et al[37] note that the coincidence of off-shore wind with peak summer loads is fairly high, and it might be possible to increase this value for at least part of the year.

Biomass

Biomass[38] systems have traditionally been subject to a variety of cost-related problems that have made them difficult financial propositions. Chief among these is the cost of fuel. Many sources of biomass fuel are assumed to be zero- or low-cost. However, two factors have frequently intervened to counter the benefit of low-cost fuel. First, it is difficult to estimate the logistical cost of gathering and transporting biomass fuel for a long period of time over a fairly broad area. In addition, it is difficult to accurately estimate the availability of fuel supply.

Second, even when steady supplies of biomass can be found, the providers have frequently used their "market power" over a plant to raise the price. This was the case, for example, for the Colmac Energy Mecca plant built in 1992 in Riverside County, California. After the plant was retrofit to also burn petcoke and natural gas, the price for biomass stabilized and the plant ran successfully until the deregulation of the electricity industry in 1999 nearly closed the plant. It has since managed to find lower cost (essentially zero cost) fuel, and is trying to remain open. [39] In some cases, this has necessitated

[35] From the Atlantic County Utilities Authority (ACUA) website, http://www.acua.com/. After this analysis was completed, BPU staff reported that actual production for the Community Energy wind project was 21,488 MWh in 2006. This output equates to a capacity factor of approximately 33%.

[36] The 29% capacity factor is consistent with the capacity factor used in the 2004 New Jersey renewable energy market assessment performed by Navigant.

[37] New Jersey Offshore Wind Energy: Feasibility Study Atlantic Renewable Energy Corporation and AWS Scientific, Inc., December 2004.

[38] The New Jersey RPS rules' definition of Class I biomass (N.J.A.C. 14:8-2.5) includes electricity produced through the combustion of the following types of biomass: 1. A bioenergy crop, as defined at N.J.A.C. 14:8 -2.2, including wood produced at a biomass energy plantation; 2. Wood from the thinning or trimming of trees and/or from a forest floor, provided that the wood is not old-growth timber, as defined at N.J.A.C. 14:8-2.2; and that the wood is unadulterated by non-cellulose substances or material; 3. Gas generated by anaerobic digestion of biomass fuels other than food waste and sewage sludge, including bioenergy crops and agricultural waste; 4. Either of the following types of wood, provided that the wood is unadulterated by non-cellulose substances or material: i. Ground or shredded pallets or other scrap wood, with all nails and other metal removed, produced at a facility that is classified as a Class B recycling facility by the New Jersey Department of Environmental Protection's Bureau of Landfill and Recycling Management, or at an equivalent recycling facility approved by the state environmental agency in which the facility is located; ii. Wood shavings and/or scrap from a lumberyard or a paper mill, excluding black liquor, as defined at N.J.A.C. 14:8 -2.2. 5. Electricity generated by the combustion of gas from the anaerobic digestion of food waste and sewage sludge at a biomass generating facility also qualifies as a Class I resource. Generators burning Municipal Solid Waste (MSW) qualify as "Resource Recovery Facility" under the New Jersey RPS' definition of Class II renewables, provided they meet certain conditions specified in N.J.A.C. 14:8 -2.6. For the purposes of this discussion, MSW-burning facilities are included under the category of "biomass."

[39] John Anderson, personal communication from plant manager in 1997, update material from http://www.ciwmb.ca.gov/LGLibrary/Innovations/RecoveryPark/CaseStudies2.htm.

renovating the boiler to allow switching to some other (usually fossil) fuel. These problems, among others, have inhibited the development of biomass plants.

Landfill Gas

The economics of landfill gas (LFG) projects are defined by factors including the age, contents and size of the landfill. Landfills with a lot of organic material that are fairly fresh will deliver more methane than older sites or sites used primarily for materials with lower organic content (e.g., industrial waste).

In 1996, the EPA promulgated regulations that forced landfills containing more than 2.5 million Mg (roughly 2.75 million tons) of waste to be capped and the gases they produced to be collected and "treated" (i.e., flared, or used for electricity generation or process heat). Many municipalities, faced with the mandatory cost of capping and treating the landfill anyway, saw an opportunity to develop a clean energy source for relatively little additional capital. This practice was strongly encouraged by the EPA, and this is the primary function of EPA's Landfill Methane Outreach program (LMOP).

New Jersey has many existing landfill methane projects. New Jersey DEP data indicate that 76 MW of LFG capacity is currently in place in New Jersey. LMOP maintains a database of both operational and candidate landfills by state which provides a lower estimate of current landfill gas capacity. The database shows 17 developed landfill methane gas (LFG) projects in New Jersey producing about 57 MW, with only three undeveloped sites. For the purposes of this assessment, the 76 MW value is being used as the assumed existing LFG capacity in the state. The LMOP data showing very few remaining candidate landfills for developing electric generating capacity is characteristic of the LFG market as a whole—larger and more productive sites are more financially lucrative and were developed first. Thus, in many states, the remaining landfills are decidedly less financially promising than the sites already developed.

The economics of LFG are strongly influenced by Federal incentive programs.[40] LFG projects are eligible to receive Production Tax Credits of 50% of the amount granted to wind and solar systems, for a period of 5 – 10 years depending on when the plant was placed in service. In June 2006, the IRS evaluated the value of the LFG tax credit to be 1.0 cents per kWh.

Publicly owned LFG projects qualify for the Renewable Energy Production Incentive (REPI). REPI funding is subject to annual appropriations in a way that does not help developers strengthen their *pro formas*.

In general, the Federal incentives have been quite successful in enticing developers to install LFG systems. And, as evidenced by the number of LFG projects that have already been developed to date, it does not appear that the cost effectiveness of LFG projects is a serious barrier in New Jersey at this time.

Indicator #10: New Jersey program expenditures

Based on the BPU data, New Jersey has spent over $132 million on completed renewable energy systems under the CORE and REPGFP programs from 2001 through 2006. Solar electric systems have received 94% of the total funding since 2001, as shown in Table 2-15.

[40] "Summary - Energy Policy Act of 2005," http://www.epa.gov/lmop/res/index.htm#3.

Table 2-15. Renewable Energy Expenditures[41]

Renewable Energy NJ program Expenditures					
Year	**Solar $**	**Wind $**	**Biomass $**	**Fuel Cell $**	**Total**
2001	$45,750	$0	$0	$0	$45,750
2002	$2,658,310	$38,830	$560,000	$710,000	$3,967,140
2003	$3,354,636	$74,400	$153,594	$710,000	$4,292,630
2004	$10,917,455	$0	$513,225	$1,687,312	$13,117,992
2005	$26,718,326	$50,000	$2,390,000	$0	$29,158,326
2006	$79,914,000	$0	$0	$1,575,000	$81,489,000
Total	$123,608,477	$336,989	$3,616,819	$4,682,312	$132,244,597

Indicator #11: Amount of third party investment support for projects

Indicator #12: Amount of local financing dedicated to RE systems.

Small PV

Data from CORE program survey results indicate that there is not a large demand for third party or local financing for small PV systems (i.e., solar electric systems ≤ 10kW). Overall, 74% of the participants in the CORE program survey did not feel that alternative forms of financing were needed.

There are at least three reasons for this result. First, the results of the survey demonstrated that the majority of the CORE program participants are high-net-worth individuals installing PV on their homes. Thirty four percent of CORE program survey participants financed their renewable energy system with cash. Fifty-one percent of CORE program survey participants reported that they had financed their renewable energy systems through a variety of homeowner financing channels, including bank loans, equity credit lines, home equity loans, mortgage extensions, mortgage loans and second mortgages. However, those pursuing PV system ownership in the future may be less wealthy than current program participants, and they may have a greater need for alternative financing mechanisms.

A second reason that there is an apparent lack of demand for third party financing for renewable energy systems in New Jersey is because of the incentives offered by the BPU. These incentives have historically reduced the payback period by over 60% on residential PV, from 22.6 years to an average 9.2 years. In general, commercial projects are estimated to have payback periods 25-35% shorter than residential projects. When the up-front rebate incentives are reduced or eliminated, there would be an increased demand for third party financing for renewable energy systems.

In contrast to the homeowners, the professional developers felt that bringing in new sources of financing was going to be critical for future growth in the small PV market. The second most common barrier listed

[41] Source: BPU program data current through 2006. This table includes a column for fuel cells because they have received BPU funding, however, these fuel cells do not count as Class I resources because they are operated on natural gas, thus the generation has not been included as generation that satisfies the New Jersey RPS elsewhere in this assessment.

by developers surveyed by the Summit Blue team was the high capital costs of PV installation in New Jersey.

Additionally, the developers surveyed did not feel that banks are structuring loans in the most appropriate way. Many developers explained that if banks allowed customers to finance a solar renewable energy system based on the value of solar as an asset, instead of the customer's credit history, more residents would be able to finance solar renewable energy systems. Developers surveyed also indicated that they thought it would be helpful if the BPU offered a solar-specific financing program with a shorter approval process to prevent loss of money due to interest accrued on funding borrowed before the BPU incentives are received.

Large Systems

In general, we would expect the availability of third party financing to be most important for funding larger systems, either solar or wind. It seems clear that the money required for these projects is available in general, but the surveys of lenders and developers of larger systems indicated a strong dependence of financing on the creditworthiness of the revenue streams from the project. As one financier put it "We can manage the production risk of the wind machines, but not the merchant risk," (for either the electricity or the RECs).

The most common suggestion to ameliorate this situation was to amend the system to encourage longer term PPAs and REC off-take agreements with some creditworthy entity in the state (i.e., the Electric Distribution Companies or suppliers, though suppliers may be less likely to be creditworthy). Each of the financial professionals interviewed expressed significant interest in investing in New Jersey, if that issue can be managed.

Indicator #13: Willingness to take on debt to facilitate system installation

Over one third of CORE program survey participants paid cash for their renewable energy systems, removing the need to take on debt to facilitate system installation. Another 17% of survey respondents funded their renewable energy systems internally. The demographic data from the survey indicates that the majority of participants in the CORE program survey were single-family homeowners with household incomes over $100,000/year, aged 45-55. This indicates that the CORE program has historically served a population with limited need for financing resources.

However, as discussed earlier, these early participants were not interested in taking on debt for the full unsubsidized installed cost of their systems (i.e., 46% of survey participants stated that they installed a renewable energy system to obtain the CORE program rebate, and 56% of survey participants reported they would not have installed a renewable energy system if the rebate were 25% less). This indicates that even participants with large disposable incomes are not interested in pursuing renewable energy systems without substantial financial incentives.

The type of consumers interested in the CORE program in the future may not have access to the same financial resources as past program participants. Future participants may be less capable of paying cash, or taking on debt to pay for their renewable energy system. This suggests that the BPU should consider adding a low or zero-interest loan component to the CORE program.

2.4 Barriers to Renewable Energy Market in New Jersey

The barriers described in this section are derived from a variety of primary and secondary sources including interviews with participating and non-participating developers, CORE program participants, financial experts, aggregators, brokers and Clean Energy Council members, and a review of literature. Interviews with market actors proved valuable because they reflect the experience of those actually working in the New Jersey market. However, the feedback from these market actors also must be viewed as anecdotal in nature, and it is not always consistent with experiences of others in the market.

The research team gathered a list of market barriers for each combination of technology and market segment (e.g., PV in residential, commercial or industrial), and examined the data for evidence of the impact of this barrier on the development of New Jersey markets. The following sections are grouped by technologies, first examining barriers common to all sectors, then breaking the barriers out that affect only a single sector for each technology.

2.4.1 Photovoltaics

Barriers across Market Segments

<u>Uncertainty about the Future of Solar Market in New Jersey</u>

The most common barrier to CORE program participation listed by developers surveyed by the Summit Blue team was the long-term uncertainty regarding SREC market values and durability of the RPS requirement.

Additionally, when commenting on barriers to installing large-scale renewable energy projects in New Jersey, many developers suggested that future uncertainty about the CORE program itself is the largest barrier. In particular, the developers surveyed pointed to uncertainty regarding long-term REC values, uncertainty regarding the availability of future rebates, long bureaucratic processes, and inability to contact the BPU to get questions answered or rules clarified.

Developers surveyed by the Summit Blue team also made numerous comments about the ineffectiveness of the CORE program and how it is impeding the solar market in New Jersey. <u>Notable concerns included</u>:

- A lack of a formalized appeals process for rejected applicants,
- Applications do not appear to be treated uniformly,
- Responses are not issued in a timely fashion,
- Denial letters are issued several months after submission with no explanation,
- Other New Jersey renewable energy programs have stopped accepting applications; and
- Absence of a clear set of rules for completing successful applications to the REPGF program.

All of these reasons point to a high level of uncertainty and distrust of the program and its future ability to fund projects.

All the Clean Energy Council members interviewed by the Summit Blue team indicated that the current administrative problems in the New Jersey renewable energy programs are a significant barrier and noted that the current funds for the renewable energy programs are overcommitted, causing frustration among all parties involved with the CORE program. Further, half of the solar manufacturers interviewed by the Summit Blue team indicated that the biggest barrier to growing their business in New Jersey was policy uncertainty and issues surrounding the availability of incentives.

While slowly moving projects out of the CORE program's solar incentive queue helps reduce uncertainty, it does not solve the larger issue of uncertainty among developers and the financial community about the future of CORE program funding. Since no plan exists for the disbursement of financial incentives beyond the BPU's current funding cycle (ending on December 31, 2008) the solar industry indicates difficulty in selling new projects. A Fall 2007 Board Order outlining a multi-year SACP schedule and describing a transition away from rebates for larger systems should begin to clarify the state's plans for the future of the solar market.

Lack of Insolation

New Jersey does not have a particularly strong solar resource. The capacity factor for solar PV in New Jersey is approximately 13% on average.[42] By contrast, California's average capacity factor is 18% and Hawaii's average capacity factor is 21%. Thus, a 10 kW system in New Jersey would generate approximately 11 MWh of solar energy annually. By contrast, the same system would generate almost 16 MWh in California and 18 MWh in Hawaii. Obviously, the low insolation levels and corresponding low production levels adversely affect the payback period or the IRR of the system for its owners.

Lack of insolation was also mentioned as a barrier to participation in the CORE program by two of the developers interviewed by the Summit Blue Team. One developer mentioned sub-optimal solar resources, and another developer interviewed stated that the interest in solar exists, but that the engineering doesn't work because the houses have too much shade.

Thin film solar technology[43] could work well in New Jersey's environment, though it appears that there has been little deployment of the technology to date. Thin film solar performs well in overcast climates, can be made specifically to be integrated into buildings (such as residential roof tiles), and produces lower cost power than standard solar PV. One of the issues with crystalline PV is the high cost of manufacture, and as New Jersey does not have strong solar resources the return on investment for this initial high cost is not as strong as in other more sunny states.

Thin film technology currently accounts for around 7% of the PV market. There are some problems with the technology, however. Some thin film materials have shown degradation of performance over time and stabilized efficiencies can be 15-35% lower than initial values. The technology that is most successful in

[42] Based on results of Clean Power Estimator analysis for typical CORE program installations.

[43] There are primarily three types of thin film technologies: Amorphous Silicon (a-Si); Cadmium Telluride (CdTe); and Copper Indium Gallium Selenide (CIGS). Amorphous Silicon had the largest share of the thin film market (64%) as of the end of 2005. It has been researched for the longest period of time, may be the best understood material of the three and has been commercial for the longest. Cadmium Telluride had 26% share of the market and is ramping up very rapidly, with Copper Indium Gallium Selenide having a 10% share of the thin film market, with great potential, but is the least understood and least developed of the three materials (from renewablenergyacess.com).

achieving low manufacturing costs in the long run is likely to be the one that can deliver the highest stable efficiencies (at least 10%) with the highest process yields.[44] This is a growing industry and the research team recommends that the BPU continue to monitor technological advancements.

Silicon Shortage

A global shortage of silicon metal has led to a shortage of solar modules in the last several years. The situation has been exacerbated by high tariff rates in Europe (notably Germany and Denmark) and generous subsidies in California and New Jersey, along with continued strong markets in Japan and other countries. This shortage of solar equipment has driven up the cost of PV modules, and has functioned as a barrier to the solar development in all market sectors.

Fortunately, silicon manufacturers indicate that the current shortage is likely to be resolved within a relatively short timeframe.

High Capital Cost

As noted above, high purchase price is a barrier to PV system development, particularly for residential consumers, but also for the small commercial, large commercial and industrial segments. In fact, 13% of the developers interviewed by the research team cited high first costs as the largest barrier to solar adoption in New Jersey, and 54% of CORE program survey participants cited first costs as the major barrier to installing a renewable energy system.

However, in New Jersey, this upfront cost has been significantly reduced by the incentives offered by the BPU. From the launch of the BPU's Clean Energy Program in 2001 through the end of 2006, the BPU incentives have resulted in the installation of over 27 MW of solar capacity in New Jersey. This PV system capacity represents 1,957 customer-sited solar installations. This rapid pace of project development will need to continue, as New Jersey must draw on the resources of over 63 MW of solar capacity in order to meet its RPS solar requirement for the 2008 RPS compliance year, and over 1,800 MW of solar capacity to meet the solar RPS requirements for 2020.

Intermittency

Solar PV is an intermittent resource. Although intermittency has a negative effect on the financial returns for all markets, it affects the utility segment of the solar market disproportionately. This is because intermittent resources cannot be relied upon for capacity unless firmed with a storage system or with another resource. At low levels of penetration this is not typically a problem for the utility, although it may potentially have adverse effects on individual distribution lines. However, at high penetrations (more than 20%) management of short term power flows can become an issue for system operators. This is more of an issue for large-scale wind than for PV.

There is plenty of historical information about how much the sun typically shines during certain seasons in different geographic areas, making solar less difficult to plan for than some other intermittent renewable energy sources such as wind. Also, the peak production of solar PV systems often coincides with the summer peak demand (caused largely by increased air conditioning load), which increases the value of solar energy generation for utilities that have a high peak demand.

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[44] Information from solarbuzz.com.

Lack of Installation Experience

Although PV installations are simple in concept, in practice installers of solar systems need special training to consistently provide high quality installations. A diverse skill set is required of a solar installer. A significant issue is the presence of high DC voltages in the systems, which requires special training for electricians.

Although 100 solar installers currently serve the New Jersey market and have been able to complete an impressive number of installations in a relatively short period of time, it is not clear that all of New Jersey's PV installers possess the level of training and experience necessary to ensure high quality installations. Twenty-six percent of CORE program participants cited competence of renewable energy companies or contractors as a significant concern prior to installing their renewable energy system. The percentage of participants with this concern after having completed the installation did drop to 6%, indicating that the majority of installers are meeting or exceeding expectations. However, even a few poor quality installations can make a bad name for the nascent PV market. In addition, one of the five manufacturers interviewed by the Summit Blue team indicated that qualifications and training of the local installer community was a barrier to growing their business in New Jersey.

This type of barrier has been successfully dealt with in other states, such as New York, with a combination of training programs and certification standards. New Jersey should take steps to promote and/or facilitate certification under North American Board of Certified Energy Professionals (NABCEP), a well-reputed organization providing PV installer training and certification programs.

Barriers Specific to Solar Market Sectors

High Levelized Cost

High levelized costs are a direct result of the high capital costs of PV and the low insolation levels. This barrier is heightened for residential consumers who cannot take advantage of the same tax benefits available to commercial entities. In addition, because of New Jersey's solar set-aside, these high levelized costs affect ratepayers.

Available Financing

Available financing does not appear to be a major barrier to the IPP market sector. Only 5% of developers surveyed believed that access to financing is the primary barrier to CORE program participation. And CORE program participants themselves did not report difficulties in accessing financing. However, depending on the future availability of the CORE rebates, financing could become more challenging if participants need to finance a much larger amount of upfront system costs.

The financiers interviewed felt that access to financing *per se* was not an issue. In fact, when describing the availability of money for financing projects one noted that "there is money chasing deals out there."

Summary of Barriers for PV

The largest issue facing the development of an ongoing PV market in New Jersey is adopting transparent and stable market rules that can provide predictable revenues—both electric revenues and incentive revenues—to support the project cost. Developing an incentive system that lenders and equity owners feel they can count on over a reasonable period into the future will resolve the issue of attracting financing to the state, and ameliorate the high capital and levelized costs associated with PV. As the market for solar project financial services—and the solar industry as a whole—matures, training and certification for installers will become routine and the demand will be met by the supply of new talent.

Clearly, New Jersey is in competition with the rest of the world for PV equipment. However, as the number of governments with incentive programs grows, the PV industry (including the silicon manufacturing industry) appears to be growing to keep pace. However, to date there is only slight evidence that these programs have actually reduced the cost of PV systems. Therefore, a clear understanding of the motivation behind substantial PV incentives and the expectations of New Jersey should be developed and disseminated to avoid future disillusionment and antipathy toward the BPU programs.

2.4.2 Biomass and LFG

Combustion of biomass (in solid form or gasified), and land-fill gas (LFG) is a much more conventional renewable energy technology than wind or solar. It typically involves fairly standard engine-generator technology fed by a less common fuel source. As such many of these plants can be dispatched—that is, called on to run when needed—and generally have relatively high capacity factors (approximately 70%). However, they still face some significant market barriers.

Biomass

Combustion of biomass may be the oldest form of energy generation known to man. However, modern plants that capitalize on it face some serious challenges relative to other more conventional fuels. Most biomass has a dramatically lower energy density than fossil fuels. In many locations, the geographic density of fuel growth is also fairly limited. This combination leads to limits on the size of the plants that can be built.

Second, managing the fuel before and after it reaches the plant creates a number of issues. Because of the low volumetric density of the fuel, transportation requires many loads with relatively small mass. Once the fuel reaches the fuel yard, it is subject to a variety of management issues. For example, fuel yard fires are relatively common in many biomass plants, as organic material in large piles can warm up and self-ignite.

Most biomass fuel is relatively inconsistent in composition and even moisture content. This variability happens not only on a seasonal basis, but also on a load-by-load basis. Managing this variability takes some skill and experience, but has been accomplished by many plants.

Some biomass fuels contain components that do not work well in traditional stoker boiler situations. For example, some plant material can contain significant amounts of silicon, which can lead to rapid development of layers of glass on the boiler tubes. Other plant materials contain trace volatile metals that will precipitate out on boiler surfaces.

However, gasifying the biomass material first, then quenching the gases to cause the volatile materials to precipitate out before the combustion process can essentially eliminate many of these types of problems. At greater cost, it might be possible to withdraw CO_2 and CO from the fuel stream before combustion, thus reducing the CO_2 emissions, if someplace to sequester the CO_2 can be developed.

Gasification also allows much more flexibility in choosing the inputs and outputs of the process. The gasification process is fairly indiscriminate about the input material. Virtually any organic material can be gasified (although changes in fuel may require adjustment of the system). Similarly, the outputs from the process can also be diverse. For example, instead of simply firing a boiler, the syngas output from the gasifier can be used to fire a combined-cycle gas turbine, which can raise the overall efficiency of power production from the low 30% range to 50% or greater. Alternatively, the biogas (or syngas) output from the gasifier can be used to make synthetic natural gas or liquid fuels (alcohol or diesel) with well-known chemical techniques. This ability to change outputs to meet local demand could be a valuable feature of gasification systems.

Finally, a historical problem with biomass fuels derives from socio-economic forces. Materials that were initially “waste” material are seen to have economic value after they become part of the plant’s fuel stream. The providers of these materials, who were typically willing to pay to dispose of them before the plant, now want to be paid for the economic value they are providing. This situation has forced a number of plants to be retrofitted with fossil-fuel burners that will allow fuel flexibility and prevent local fuel suppliers from exercising market power.

Because biomass generators produce air emissions, another category of issues for biomass generators is permitting and siting. Developers indicated that the most frustrating aspect of the permitting process is that it is lengthy. This both slows project construction and adds administrative costs. In addition, NIMBYism was cited as an issue for all non-solar resources.

Having identified these barriers, biomass combustion is a technically viable technology. Most, if not all of the problems identified above are amenable to technological solutions. The major forces inhibiting more rapid and widespread development of these plants appear to be a) identification of a geographically compact area that can provide a sustainable level of fuel, and b) the cost of gathering and managing such a low-energy-density fuel from its source to the boiler or gasifier. These issues make it difficult to develop a solid *pro forma* for these projects that will attract financing. Should these issues be resolved in New Jersey, biomass combustion plants may have a notable role to play in the state’s energy infrastructure.

Landfill Gas (LFG)

LFG also uses well-known and proven technology. Landfills are the largest man-made source of methane in the U.S., accounting for 37% of anthropogenic emissions.[45] LFG plants have become more common largely because of 1996 Federal regulations[46] that forced larger landfills to cap (place an air-tight cover over the top of) the landfill, and then collect and flare the gas in order to reduce GHG emissions. Once a landfill has been capped, it is a relatively simple technological issue to install an engine-generator set to use the gas. Currently 119 MM tons CO_2eq are either flared or used in engines (roughly 50% apiece) in the U.S.[47]

However, the economics of LFG are less obvious. For starters, the gas production of any landfill varies depending on what was disposed there. Waste streams high in moist organic material (e.g. municipal solid waste) produce more gas than other waste streams with drier or inorganic materials. Then, the output from any particular landfill declines over time, at a rate that can be difficult to predict. This increases the risk of

[45] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, (April 2007), USEPA #430-R-07-002, Chapter 8, Waste. http://epa.gov/climatechange/emissions/usinventoryreport.html

[46] 1996 federal regulations that require large municipal solid waste landfills to collect and combust landfill gas: 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005.

[47] US EPS inventory, *ibid*.

installing equipment with large capital-costs, and has led to development of modular gen-sets that can be removed incrementally (presumably to another site) as the gas flow declines.

The supply of landfills suitable for capping and gas collection is also a limiting factor for LFG. The legislation mandating caps on larger landfills has been in place for over a decade, and most of the largest (and most economic) landfills have already been converted. The EPA lists 14 existing LFG projects in New Jersey, and only 3 existing opportunities.[48]

LFG projects are eligible for a variety of Federal incentives, many of which were modified in the Energy Policy Act of 2005.[49] These Federal incentives include a production tax credit of $0.009/kWh, and can significantly enhance the economic viability of an LFG project.

Additional issues for LFG projects relate to location and size. Because of the low energy density of the gas produced (typically 300-500 Btu/scf, or roughly one-third to one-half the heating value of pipeline gas), it is usually not economic to pipe the gas very far. Thus, unless there is an industrial host facility nearby, it is frequently not possible to use the gas for combined heat and power facilities.

Finally, most LFG projects are fairly small in scale, typically less than 10 MW, with many less than 5 MW. This can be a difficult size to exploit economically in today’s energy market. Because of the small size of the plants, there is little opportunity to use the gas to drive a combined cycle plant. Obviously this limits the efficiency of LFG plants, and thus their economics.

Summary

Biomass plants have significant potential in New Jersey if developers can overcome uncertainties around fuel supplies. However, even with strong fuel supplies the economics of biomass plants will depend strongly on the availability of creditworthy off-take agreements.

Development of additional LFG plants will be very limited by the availability of suitable landfills.

2.4.3 Wind

Barriers across Market Segments

Lack of Wind Resource

New Jersey does not have particularly strong wind resources. This is a barrier for all market sectors (residential, small commercial, large commercial, industrial, public entities, utility, IPP) because financial returns for wind plants with a poor wind resource and a low capacity factor generally do not meet investor requirements. A feature that will be critical in evaluating the cost effectiveness of any system is the capacity factor, which measures how much annual energy a system of a given size will produce. For wind systems the capacity factor is driven almost entirely by how strong and how frequently the wind blows on a particular site. For this reason, the financial benefits of a wind system are very sensitive to the assumptions about capacity factor.

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[48] US EPA Landfill Methane Outreach program statistics, http://www.epa.gov/lmop/proj/index.htm#2

[49] www.epa.gov/lmop/conf/9th/Presentations/joneslaura.pdf

One third of the wind manufacturers surveyed by the research team indicated that the main barrier is the lack of high category wind, and that without more Category 3 or 4 wind resources, it is not economically viable to build large scale land-based wind projects in New Jersey.

Permitting - NIMBY

Permitting is a barrier for all on-shore wind market segments (residential, small commercial, large commercial, industrial, public entities, utility, IPP). One third of manufacturers interviewed by the research team indicated that permitting was the major barrier to siting more wind systems in New Jersey. Developers who have not participated in the CORE program commented that siting is a major barrier to installing larger scale renewable energy projects, and further that the permitting cycle is quite long.

Siting has also proven to be a significant barrier for the development of off-shore wind farms in the U.S. Because the concept is new, permitting standards have not been developed. And, because the turbines would likely be located outside a state's jurisdiction, but the cables carrying the power come to shore within the state, both the state and the Federal government have legitimate regulatory interest. Opponents of off-shore wind farms have used this uncertainty in regulatory primacy, along with the novelty of the permitting process, to stall development of projects. The project that is probably the furthest along (Cape Wind, proposed for Nantucket Shoals off of Cape Cod, MA) has been trying to secure permits since roughly 2000.

Large Upfront Cost

Large upfront cost is a barrier to all wind segments (small and large commercial, industrial, public entities, utility and IPP).

As described above, high capital costs are a problem for nearly all renewable systems. A solution to this barrier is a creditworthy source of off-take revenue that will back the investment required. In interviews with financial investors, a common statement was that the financial community can handle the production risk (the risk of the project not producing as much power as projected), but cannot manage the merchant risk (the risk of not being able to sell that output).

High Levelized Cost

The combination of high capital cost and limited wind resource leads to high levelized costs for power produced from wind systems. This is a barrier to all of the wind market segments in NJ.

Turbine Shortage / Costs of Steel

Turbine shortages and the high cost of steel are barriers to the public entities, utility, IPP market segments. Turbine prices are a great example of regulatory uncertainty creating market barriers. The Federal government has been reluctant to extend production tax credits (PTCs) routinely or, until recently, to extend them for multiple years. However, production of wind turbines and generating equipment is a capital-intensive process that requires long lead times. The juxtaposition of these two features has created a boom-bust market for wind machines. When the PTC is in effect, developers rush to secure turbines for their projects in order to get the project installed before the PTC expires. When the PTC is not in effect, the U.S. market for turbines collapses. This inhibits further investment by the turbine manufacturers, which leads to shortages during the next boom cycle.

The cost of steel is an example of how renewable technologies can be heavily influenced by economic forces well outside the normal realm of renewable power generation. A worldwide rise in the cost of steel in recent years has increased the cost of wind equipment noticeably (this is particularly true for the towers themselves, which use substantial amounts of steel). Although this price increase is associated with conditions in the global steel markets that are entirely unrelated to wind power or renewable energy, the price increase has been difficult for a new and relatively immature industry.

Intermittency

The intermittent nature of wind production is a barrier to the public entities, utility, and IPP market segments. The market value of power sources increases as their reliability increases. Wind suffers both because it is intermittent, and because it is perceived as unpredictable. However, the European experience in predicting wind conditions should ameliorate this concern over time as predictive algorithms become more sophisticated. In addition, utilities are beginning to understand the value of considering the production of a particular wind plant as part of a portfolio of sources that have low covariance (i.e., they do not tend to produce power at the same time). In addition, utilities have gained experience in managing intermittent wind sources in much the same manner that they manage intermittent loads. Finally, power brokers are developing schemes to "firm" wind production by supplementing it with other generation sources. For example, in the northwestern U.S., the Bonneville Power Association offers a firming product based on their hydro capacity. However, markets for such products are more immature on the east coast of the U.S.

Overall, this appears to be a barrier that owes much to the immature state of the industry and the novelty of the resource in the utility's operating scheme. Although it will continue to be an issue, the scope of the barrier should decline significantly over time.

Ineligibility/Uncertainty of Production Tax Credit

Public entities are not eligible for the federal production tax credit, which creates a barrier for them in the sense that they must find another entity with an appropriate tax appetite to use the production tax credit.

As mentioned above, utilities and IPPs face a significant barrier in the uncertainty surrounding the continuation of the federal PTC. However, another problem for public entities was that because of their tax-free status, they were unable to take advantage of the financing options that the PTC created. This situation has been mitigated by several developments. The first is the development of power purchase agreements (PPAs) in which a local government entity agrees to purchase the power from a project over some relatively long period of time (e.g., 7-10 years). As described above, this creates a creditworthy off-take for the power, and allows commercial financing, including equity players using the PTC, to build the plant.

The second mitigation to the problem with public entities occurred with the passage of the Energy Policy Act of 2005 Clean Renewable Energy Bond (CREBs) legislation.[50] This legislation allows local governments to issue a special class of zero interest bonds to finance renewable energy projects. The purchasers of the bonds receive their returns through a series of annual tax credits. (In effect, the Federal government pays the interest on the bonds as forgone tax revenues). This mechanism is potentially attractive for many local governments. However, the application process is not trivial, and the program is

[50] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1303, 119 Stat. 991, 992-997 (2005).

limited by an annual allocation cap. Projects are prioritized for funding based on a formula that emphasizes smaller projects, among other criteria.

Small Wind

A working group was formed in October, 2006 to discuss and identify opportunities and barriers associated with terrestrial wind development in the state. The Wind Working Group ran a stakeholder survey, the results of which show the key strengths, weaknesses, opportunities and threats for small wind development. Table 2-16 shows the top five factors for each of the survey sections.

Table 2-16. Key Factors Impacting the Development of the Small Wind Market in New Jersey

		Percent Agreeing
Strengths	Favorable net metering laws	88%
	Rebate factor a huge incentive for small scale systems and municipalities	80%
	Viable, proven Renewable Energy Credit market	80%
	The availability of existing wind resources in NJ	80%
	Initial investment in Wind is lower cost than other renewable resources	68%
Weaknesses	Inconsistent local zoning and variance laws	88%
	The lack of accurate available wind data	76%
	No requirements in RPS for utilities to purchase class 1 wind power	64%
	NJBPU may make wind projects to solar queue	60%
	Underperformance of existing systems and limited data available	56%
Opportunities	Using entities of critical infrastructure as demonstrations (e.g. schools)	68%
	Kick start small wind projects by mimicking the recent PV boom and implementing performance based incentives (perhaps a wind REC?)	68%
	NJWWG great opportunity to merge stakeholders and influence policy	64%
	Taking advantage of some of the locations where there are available wind resources	64%
	Initiating a short and long term megawatt goal to drive small wind	56%
Threats	The authority of local officials to interpret ordinances	72%
	That concern BPU may be moving rebates to the back of the solar queue	64%
	The latitude inherent in zoning ordinances	56%
	Actions of the “Not In My Backyard” groups	52%
	Lack of confidence in the accuracy of the wind map	48%

The results of the survey show that although there are many opportunities for the expansion of small wind, significant barriers exist. The most important one is the inconsistency in local zoning ordinances and variance laws, and the way these laws are interpreted. Other important barriers are the lack of reliable wind resource data, and the lack of confidence in future income from the REC market because there is no specific REC market for wind energy (such as there is for the solar market in SRECs). Key opportunities that already exist are: good net metering laws, the availability of rebates, and a viable REC market.

In an interview with Summit Blue, Dr. Michael Muller[51] of the Wind Working Group said that siting issues were the main barrier to the development of small wind. These siting problems involve difficulties with zoning, complaints from local residents, and the difficulty in analyzing wind resources at a particular site. Because planning laws vary by municipality, there is no consistency in zoning issues across the state, and some municipalities are much more wind-friendly than others. This zoning issue is also heavily influenced by NIMBYism (i.e. local residents objecting to the sight of a wind turbine). Other barriers he cited were a lack of anemometers for loan (their own program has run out of funds), and a lack of support for potential wind installers to go through all the processes involved.

One of Dr. Muller's recommendations was for a statewide education and outreach program to overcome the common misconceptions that exist in the general public about small wind and its costs and benefits. Another recommendation was for a specific small wind program that would help early adopters to go through the whole process: loaning anemometers for an assessment of resources at a potential site and helping with the planning application, cost analysis, turbine installation, and maintenance plan. A third idea is to create a template for codes and standards for small wind that could be adopted by townships across the state.

Another type of small wind is architectural wind, which is the class of wind turbines that are installed on buildings. This is an emerging technology, and has not been proven to work on a large scale in the US. However, there are several manufacturers around the world who are already selling and installing models specifically developed for rooftop installation. [52] In the UK, residential rooftop turbines are being actively promoted by utilities such as British Gas. A 4.8 kW commercial demonstration project was installed on the Adventure Aquarium in Camden, NJ, by AeroVironment in April 2007. This is a technology that could potentially fill a gap in the New Jersey renewables market because wind is a cost-effective renewable technology but there is a lack of good sites for large scale on-shore wind. Architectural wind would work well within New Jersey's large urban environment, and it is a good complement to solar in terms of the times in which it produces power. However, this technology is in need of research and development funds so that the technology can be fully evaluated.

To conclude, although the Navigant report did not give a specific potential number for small wind, there are wind resources in the state that could be harvested with small terrestrial wind turbines. There are many potential early adopters contacting the Wind Working Group that are unable to proceed because of the barriers that currently exist. These people could contribute significantly to Class I renewables with more help and support, and with greater consistency in permitting and siting rules across the state..

2.4.4 Offshore Wind

Offshore wind is New Jersey's second largest potential renewable energy resource, after solar. Although currently there are no offshore wind turbines installed in the U.S., this is an established technology in other parts of the world.[53] There was almost 900 MW of installed capacity in Europe as of the end of 2006. By the end of 2006, a total of almost 900 MW of offshore wind farms had been constructed around

[51] Dr. Muller is a Partner of the Office of Clean Energy and New Jersey Anemometer Loan program, and Professor at Rutgers University,

[52] Manufacturers of residential rooftop systems include: Windsave Ltd (www.windsave.com), and Renewable Devices (www.renewabledevices.com). Manufacturers of commercial systems in the USA include: AeroVironment (www.avinc.com); a full listing of European urban wind manufacturers can be found at www.urban-wind.org.

[53] www.ewea.org.

Europe, in the coastal waters of Denmark, Ireland, Netherlands, Sweden and the United Kingdom. Over the past two years, individual projects have increased in size to more than 50 MW, with the largest development so far – the 166 MW Nysted wind farm off the southern coast of Denmark – starting to produce electricity in December 2003. Other projects in the pipeline will be more sizeable, reaching 1,000 MW.

There have been quite a few recent developments in New Jersey's offshore wind development activities since the publication of the feasibility study in December 2004.[54] One was a survey conducted by Lieberman Research Group of New Jersey shoreline residents and visitors to find out what their opinions on offshore wind are. The survey showed that:

- People are in favor of offshore wind by a margin of two to one.
- Visitors were neither more nor less likely to visit the New Jersey shore because of offshore wind.
- The farther away from the shore the turbines will be, the higher the percentage of people in favor of them, but even at 3 miles out from shore there was still a majority in favor.

The survey indicated that public opinion was not a significant barrier to offshore wind.

Another recent development is the issue of an RFP for an offshore environmental study of the impacts of wind turbines and where they can be sited. The study will be completed by September 2009 and has a budget of up to $4.5 million.

In an interview with Summit Blue, Joe Carpenter of the New Jersey Department of Environmental Protection (DEP) highlighted some of the most important developments.

- An RFP has been issued by the New Jersey DEP for a coast-wide environmental impact assessment related to wind, which will include impacts on avian and marine life, and a mapping of appropriate zonal areas to see which ones are viable.
- The Governors Energy Master Plan assumes roughly 1,000 MW of offshore wind will be installed by 2020.
- The final decisions on offshore wind permitting will be made by the Governor's office; DEP is providing background research & studies to inform the decision.
- DEP will be involved with permitting for coastal turbines (within 3 miles of the shore); The Minerals Management Service of the Department of the Interior will be responsible beyond that limit.
- A coastal zone management plan has been filed by New Jersey with the Federal government, which strengthens their position.
- Success factors for the offshore pilot project will be: minimizing avian impact (migratory), minimizing other environmental impact issues such as shellfish, sandbar sites, storm water outfall pipes, electromagnetic fields, noise impacts, and heavy traffic.
- The information gathered by the Cape Wind Project will be used by New Jersey. Long Island Power also proposed an offshore wind project which was recently cancelled due to anticipated high costs.

[54] *New Jersey Offshore Wind Energy: Feasibility Study*, December 2004, Atlantic Renewable Energy Corporation.

Based on the commissioning of the study by the DEP, which is not due to be finished until the fall of 2009, it is unlikely that any offshore wind turbines will be built before 2010 at the earliest. This study is an essential step in the process to the permitting of offshore turbines, but the length of time it will take is indicative of the complications that exist with offshore wind development, as compared to other renewable energy technologies. The Cape Wind Project has been working for over seven years to develop Massachusetts' significant offshore wind resources and is now in the final stages of environmental impact studies. That project hopes to start building turbines and installing them in 2010.

Once offshore wind does start to be installed the build rate will depend on issues such as weather and availability of specialized equipment. Build rates for offshore wind farms in Europe have been as quick as 2.1 days per turbine (Horns Rev, Denmark), or 9.1 days per turbine (North Hoyle, UK).[55]

Summary

Overall, the primary barriers to development of wind in New Jersey appear to be a mediocre resource, a highly uncertain process for permitting off-shore plants and availability of creditworthy off-take agreements. Of these barriers, New Jersey has some control over the availability of off-take agreements and permitting issues.

2.5 Additional Market-Level Research Issues

The BPU requested feedback on a variety of research issues as part of the market assessment. Those research issues that have not been addressed elsewhere in the report are identified and discussed below.

2.5.1 Coordinating with EDCs on DG Siting

Research whether it makes sense to coordinate with distribution companies on the issue of distributed generation (DG) siting and, assuming it makes sense, the most effective means for achieving coordination.

In the United States, virtually all power interruptions are caused by the grid, and most of those grid failures are in distribution, not transmission.[56] One potential option to make the grid more resilient is to distribute the generation more broadly. This helps the grid failure problem in two ways. First, since there are now more small generators, it is more difficult for a problem with any single one of them to disrupt the grid. Second, because the generation is distributed across the grid it is more difficult for any particular load to be completely isolated from all of the generation.

A particularly interesting question is whether distributed generation can be used to forestall or eliminate the need for distribution upgrades (i.e., upgrades in substations or distribution lines). If the utility were to

[55] *Economies of Scale, Engineering Resource and Load Factors,* Prepared by Garrad Hassan and Partners (C A Morgan, H M Snodin, N C Scott) for the Dept of Trade and Industry / Carbon Trust, UK, December 2003

[56] Amory Lovins, Small *is Profitable,* Rocky Mountain Institute, Snowmass, Colorado, 2002, p190.

introduce generation on the customer side of the meter, that could reduce the stress on the hardware and potentially avoid the need for an upgrade.[57]

However, this approach has not been a typical response of utilities. More commonly it is assumed that the load on the customer side of the constriction will continue to grow, and so any effort to either minimize the load or increase the generation will be a "stopgap" at best. This problem is compounded by the fact that utilities have traditionally been reluctant to invest in facilities that they do not own.

Within the context of New Jersey's renewable incentive programs, the question arises whether it would be beneficial for the BPU and the New Jersey distribution companies to collaborate on installing renewable systems on the customer side of hardware that already—or will soon—present a constriction in the flow of power. The notion is that, since the state is incentivizing the renewable systems anyway, it should direct these incentives to help defer or eliminate the need for system upgrades, thus maximizing the benefits to New Jersey's ratepayers/taxpayers.

To test the viability of this idea in New Jersey, the research team spoke to a representative of one distribution company who expressed the opinion that it would not be beneficial for distribution companies to coordinate with customers because: a) customer sited DG is too unreliable, and b) the utility is responsible for providing reliable service. The representative was also resistant to the idea of permanent utility-sited DG due to concerns about grid congestion shifting as development shifts.

The distribution company believed that the largest barriers to siting any type of DG in New Jersey were permitting requirements, particularly environmental (e.g., air emissions) and regulatory requirements.

The research team also spoke with PSE&G. This representative focused more on a proposal that PSE&G had submitted to the BPU in response to a solicitation on this subject. According to the representative, in May 2006, PSE&G submitted a proposal to the BPU for Distributed Energy Resources State Technologies Advancement Collaborative funding, which the BPU rejected.[58] PSE&G proposed to select constrained areas of the distribution system and employ one or more energy storage devices behind the meter on a customer site or on the utility system. Given the timing of the interview, the interviewee did not comment on the BPU's response to PSE&G's more recent proposal to participate in financing solar projects within its service territory.

From both business-case and political points of view, this is a difficult concept to enact in practice. It involves cooperation among several players (e.g. the utility, the customer/host, and the BPU) who are not necessarily incentivized to work together, and it also involves utilities making investments (smaller amounts for generation located on a customer site) that they have not historically made. In order for New Jersey to move forward on this issue, both the utilities and the BPU will need to openly agree to recognize the value of this kind of arrangement, and then move forward together.

[57] See http://www.masstech.org/renewableenergy/public_policy/DG/resources/CongestionReliefPilots.htm, where the Massachusetts Technology Collaborative and NSTAR electric utility are collaborating to demonstrate this approach.

[58] New Jersey Board of Public Utilities Docket No. EO0602009.

2.5.2 Linking Energy Efficiency and Renewable Energy

Research the potential benefits from linking energy efficiency and renewable energy incentives and potential barriers to the development of renewable energy projects created by any new program requirements. Provide information to assist in designing any recommended program modifications.

Several approaches that could be used to encourage energy efficiency are explored in this section:

1. An enhanced rebate for Energy Star certified buildings (CORE current policy);
2. An enhanced rebate for installing specific energy efficiency measures at the customer site, for non-Energy Star certified buildings (through one of the BPU's energy efficiency programs);
3. A requirement to perform a non-binding energy audit to participate in the CORE program;
4. A requirement that participants go through a home performance program before being accepted into the CORE program, with a full renewable energy rebate being given only to those who install all of the cost-effective efficiency upgrades recommended by the home performance program;
5. A minimum energy efficiency requirement for participants in the CORE program.

2.5.3 General Benefits of Combining Energy Efficiency and Renewable Energy

Cost Effectiveness

Standard energy efficiency measures (i.e., lighting upgrades, building envelope improvements, and HVAC system enhancements) are the most cost-effective means of reducing generation from non-renewable sources of power, as in most cases reduction in demand is quicker and cheaper to implement than creation of new supply – especially renewable supply. Therefore, it is logical for energy efficiency to be pursued at the same time as renewable energy generation if an overall reduction in non-renewable generation is the goal. This approach makes the most use of the renewable energy kW that are generated, and the embedded energy required to build and install the installations.

GHG Savings

Combining energy efficiency and renewable energy produces a multiplicative effect on greenhouse gas emissions savings. This is because the same end use applications (i.e. lighting, motors, refrigeration, etc.) can be run using fewer kWh, and the kWh used will have lower carbon intensity. Thus, the combined effect can be represented as:

GHG savings (CO_2) = energy demand savings (kWh) * reduction in GHG intensity (CO_2/kWh)[59]

Shown here are the expected CO_2 savings from their energy efficiency and renewable energy programs, and the expected combined savings.

[59] For example, results from the report titled *Electric Energy Efficiency and Renewable Energy in New England: An Assessment of Existing Policies and Prospects for the Future* by The Regulatory Assistance Project, Montpelier, Vermont (May 2005) show this effect.

Table 2-17. Expected CO_2 Savings

	CO2 Savings
Combined Potential Emissions Reductions due to Existing, Planned and Phase II Imputed Renewable Generation to meet RPS, and current Energy Efficiency programs maintained, 2000-2010 (tons)	31,682,718
Emissions Reductions due to Existing, Planned and Phase II Imputed Renewable Generation to meet Portfolio Standards, 2000-2010 (tons)	9,163,126
Emissions Reductions due to Electric Energy Efficiency, 2000-2010 (tons)	18,767,151
Reductions due to EE and RE Added	27,930,277
Percentage increase in Combined savings vs Added Savings	13.4%

Congestion Relief

Another benefit of energy efficiency is its contribution to reducing congestion at peak times. Air conditioning is the main contributor to peak demand on summer afternoons, and electric heating if used widely can cause demand spikes on cold winter mornings. Solar PV also impacts summer peak demand, although the peak output will most likely be a few hours before the peak demand of the system. (This benefit was cited by the BPU as a rationale for focusing on solar).

The combination of these two measures – for example, an upgraded HVAC system and building-mounted solar PV – would help to reduce peak demand on a per building basis much more than solar PV on its own. How much this combined effect could be worth to utilities, which often have to pay very high prices on hot summer afternoons, is an analysis that is worth doing, especially from a ratepayer's perspective. These savings could possibly be as high as the value of demand response at peak times, although the possibility that maximum solar irradiance will not be available when it is most needed is an issue that needs to be factored into any analysis.

Reduction in RPS Goals

The RPS is defined in terms of a percentage of total energy use (i.e. MWh). Therefore, if statewide energy use can be reduced, this will reduce the RPS requirements. This applies to all categories of renewables, including the solar set aside.

Leveraging Interest in Renewable Energy to Reach Customers not Interested in Energy Efficiency

It is likely that program participants' interest in renewable energy can be used as an opportunity to trigger additional interest in energy efficiency, especially in relation to buildings not previously reached through the BPU's energy efficiency programs. In this way, the BPU would substantially increase the cost-effectiveness, efficiency, and overall impact of its entire portfolio of programs.

Benefits for Customers

From the perspective of end users, implementing energy efficiency measures can reduce the size of any renewable energy system needed to meet a customer's load, thereby increasing the amount the customer earns in avoided electricity payments. This would help to increase the return on investment that customers get. However, this would not affect upfront costs as customers are paid rebates based on the capacity installed, and not on the energy produced.

2.5.4 Feedback from Developers and Program Participants

Currently, the CORE program offers an enhanced rebate to those residential end-users whose homes have been certified through the Home Performance with Energy Star program.[60] Here are some comments from CORE program developers were asked to comment on the value of this program feature and their feedback is summarized here.

- *Prefer that energy efficiency measures be required of participants… With the incentive adder, there is less carrot than meets the eye. And it doesn't apply to new construction. The sad thing is that most new houses don't meet Energy Star standards (about 80% in New Jersey). Ultimately this does not stop solar from being put on houses that are poorly insulated.*
- *The Energy Star adder disproportionately benefits new construction, so it is unfair. It should be available on a retrofit basis. It would be better to create more efficient new construction through other mechanisms than linking it to PV, e.g., stronger building codes.*
- *Prefer that energy efficiency measures be required of participants, because most of the money is going to go to 3rd party financers. Do it for commercial too, and not just residential. In fact, it would be unfair to do it for residential alone.*
- *Keep energy efficiency completely separate… the adder approach is not fair to people who cannot make efficiency improvements.*

The survey results include the following:

- Most participant developers (70%) do not support the idea of requiring energy efficiency improvements to be completed before customers can qualify for renewable energy rebates.
- Many respondents contend that they support energy efficiency but believe customers who opt to install solar PV at their site should not have additional burdens or obligations imposed on them.
- The comment was made a few times that customers who do install solar PV often become more interested in monitoring their energy use and tend to reduce their energy use.
- Most respondents (70%) prefer the "incentive adder approach" over requiring energy efficiency measures to be installed prior to receiving a CORE program rebate. However, a number of participants said that they believe the incentive adder approach is not available throughout the state, and that this approach favors new construction over existing buildings.

[60] CORE Program Update, August 17, 2006.

These comments show a mixed response to the policy from developers, with some wanting it to go further than it does now, and some thinking that it is unfair and may deter participation. The issue of whether the incentive adder is available for existing buildings seems to be important to many.

Results from the end-user surveys for CORE participants show that:

- 77% have taken steps to improve the energy efficiency of their home or building (21% said they had not);
- 6% obtained their Energy Star home certification in order to be eligible for the enhanced rebate (92% said they had not);
- 64% think that energy efficiency improvements should be part of programs like CORE as a prerequisite (31% of respondents said no).

This shows that the current enhanced rebate is not instrumental in encouraging people to get Energy Star home certification, although it may encourage people who already own a certified home to participate.

One of the main drawbacks of the current policy is that existing buildings cannot qualify, as they cannot be Energy Star Certified, and these represent a very large percentage of building stock in New Jersey. In addition, the survey shows that the additional rebate does not encourage most people to choose to purchase an Energy Star rated property over one that is not. Ideally, if rebates are offered then they should be a major deciding factor for customers who are trying to decide whether to invest in energy efficiency.

2.5.5 Options for Including Energy Efficiency in the CORE Program

There are several approaches that could be taken to increase the efficiency of buildings that have renewable energy installations through the CORE program, based on incentives and requirements. In general, putting too many requirements on participants may deter participation, but on the other hand, having no requirements at all does nothing to encourage efficiency directly and makes the program less effective in the long run.

The approaches outlined here range from the least imposing (no requirements and small added incentive) to the most imposing (minimum energy efficiency standards).

1. **An enhanced rebate for Energy Star certified buildings (current policy).** The research team does not have any data on how many people have received the increased incentive, but our survey suggests that it has not had a significant influence on participants' decisions to purchase an Energy Star home. However, it may have encouraged those with certified homes to participate in the program. The effectiveness of the current policy is difficult to evaluate, but survey results from both developers and customers point to the likelihood that promoting energy efficiency more aggressively would generally be well received.
2. **A requirement to perform a non-binding energy audit.** This is the approach taken by the California Energy Commission for their California Solar Initiative. All participating projects must undergo an energy audit, but the audit requirement is waived for buildings with LEED or Energy Star certification. This requirement would encourage building owners to think about energy efficiency at the same time as renewable energy, although none of the recommendations from the audit would be required to be done. This option could also include some educational outreach to help participants understand how to make the most of their renewable energy system with the use of energy efficiency. This approach would require an extra payment by the participant for the audit, but otherwise would not be much different from the current policy and should be relatively simple to administer.

3. **An *enhanced rebate* for participants that go through a building performance program.** This option would make use of the BPU's existing portfolio of energy efficiency programs, such as the Home Performance with Energy Star program, by encouraging participants to participate in them before installing a renewable energy system. Although this would increase the complexity of the application process for the CORE program, the procedures and expertise already existing in the BPU's energy efficiency programs would not have to be duplicated. Ideally, this option would encourage a higher standard of efficiency in participating buildings than with Option 1. This is because Option 1 is limited to new residential homes, and Option 3 could be utilized by a much wider group of people. The enhanced rebate would have to be set high enough so that it is worth it for people to make the extra effort to go through the home improvement, but not so high that it is not cost-effective.
4. **A *minimum requirement or adjusted rebate* linked to participation in a building performance program.** This is the most stringent approach as it changes the requirements for participation, and although it would mean that the electricity generated by each renewable energy installation would be used to its greatest effect, there is a possibility that it would reduce participation numbers. For the adjusted rebate option, the full rebate would be given only to those who have been through a full energy audit and have installed all of the measures recommended as being cost-effective; if these measures are not installed, a reduced rebate would be given. For the minimum requirement option, only those buildings that have been through the full audit and have installed all recommended measures would be able to participate in the program.

2.5.6 Technical Requirements and Candidate Efficiency Improvements

Candidate Efficiency Improvements

From the standpoint of reducing congestion at peak times, the best end use applications to target with energy efficiency are those that are used most at peak times, such as air conditioning. Coupling these efficiency improvements with renewable energy technologies that also produce energy at peak times would produce a multiplicative effect, reducing peak demand at the customer site, and thus reduce congestion and peak prices. Thus, solar PV combined with an air conditioning upgrade, or direct load control of AC would be a good combination.

From the standpoint of customer savings on their electricity bill, the net kWh used in the building needs to be reduced as much as possible – i.e. energy used minus energy generated at the site. The efficiency improvements that produce the most energy savings in the building per $ of investment would be the best ones to implement, regardless of the type of renewable energy system installed. However, if the customer is on a time of use or real time pricing rate then equipment that runs at peak times should be targeted to gain the most return from the investment.

California's SB1 bill originally required that all ratepayers with a solar system subscribe to time-variant pricing if available, which seems like a good idea in order to gain the most from the PV investment. However, this policy backfired, as many customers were worried that their electricity bills will go up if they subscribed to a TOU rate, and thus the participation rates in the program fell considerably initially. If something like this policy is implemented in New Jersey, the full scope of potential impacts should be evaluated (i.e., which range of systems sizes would benefit v. suffer under a TOU rate) if a TOU rate requirement or incentive is introduced.

As the focus of the RPS is on electricity and not other forms of energy, another way to look at this is to see how end products such as lighting and heating can be produced with the least use of electrical power, so as to utilize the energy produced by the renewable energy system as much as possible. Electrical resistance heating, for example, uses a lot of electricity and is an inefficient way to heat a space. Technologies such as CHP (combined heat and power) are highly efficient and reduce the amount of fuel needed to produce heat and electricity.

To conclude, efficiency improvements that save the most energy, but also save demand at peak times, would be the best candidates. The following list includes the most obvious candidate technologies for increased efficiency or replacement. However, further research would be needed to examine other potential applications:

- Building envelope – saves energy during every hour, and at peak times, through reducing loss of heat or cool through the walls, roof, and windows of a building.
- Electric resistance heating – can add significantly to peak demand on cold winter mornings and uses large amounts of electricity.
- Air conditioning – contributes most to summer peak demand.
- Commercial/industrial motors – variable speed drives and high efficiency motors reduce energy use throughout the year, and motors used in industrial processes can contribute to peak demand.
- Domestic hot water heaters (electric) – contribute to demand during peak times in the winter.

Technical Requirements – Establishing Efficiency Levels

There are several established ways to rate the energy efficiency of buildings:

- The Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ (for commercial buildings)
- New Jersey Energy Star Home Certification (for new homes)
- Professional Energy Audits (for existing residential or C&I buildings)
- Energy Utilization Index (kWh per year/sq.ft.). This gives only a very approximate evaluation of the building's efficiency and varies considerably by building type and use. However, the kWh used per year and square footage information is generally easily available, so this method is quick to do and involves no on-site visits.

Each of these approaches includes analysis to different levels of detail, guarantees different efficiency levels, and can be applied to different types of buildings. Energy audits can vary considerably, from self-guided online audits to detailed on-site measurement and testing. Audits may be done on a high level with just a visual inspection, or in detail with procedures such as blower-door tests.

If an audit requirement is added to the CORE program, it is important that auditors be registered, and that the audit procedure is standardized so that all audits are done to a minimum standard and include enough detail to produce reliable recommendations for the building owner. Installation contractors could be trained to do the audit through the Building Performance Institute.

2.5.7 Summary of Findings

Large benefits could be gained by combining energy efficiency and renewable energy implementation. Therefore, the research team strongly encourages the BPU to increase efforts to link energy efficiency with CORE program participation. Four basic approaches to the inclusion of energy efficiency in the

CORE program were presented in this section. The research team recommends a combination of these options in which CORE participants would receive a slightly enhanced rebate for having a certified Energy Star Home, or for participating in a building performance program. In addition, all program participants should be required to demonstrate that their building has either had an energy audit or has as implemented significant energy efficiency measures prior to program participation.

2.6 Overall Market Level Findings and Recommendations

2.6.1 Findings

- As of December 31, 2006, 39 MW[61] of Class I renewable energy generation capacity was installed with the assistance of the BPU program funding; of which 27 MW was solar PV. In order for the BPU to achieve its goal of installing 300 MW of Class I resources, an additional 261 MW of Class I renewable energy must be installed by December 31, 2008; of which 63 MW must be solar PV.

- As of 12/31/06, New Jersey's Class I and Class II renewable energy systems generated enough electricity to supply 1.05% of the state's electricity demand (0.64% Class I, 0.37% Class II and 0.04% solar). In order for the BPU to achieve its goal, it must install enough eligible RE capacity to generate an additional 3 million MWh of Class I generation, 1.8 million MWh of Class II generation, and 88,000 MWh of solar generation by December 31, 2008.

- Past CORE participants have tended to be wealthy homeowners, many of whom pay cash for their PV systems (33%), and who do not have trouble accessing financing. Developers agreed that access to financing is not currently a significant barrier, but that in the future the demographic of consumers interested in participation may have more trouble financing their systems. Developers also highlighted that lenders do not view a PV system as an asset in analyzing a borrower's home equity, and suggested that the BPU offer a PV-focused financing program that recognizing PV as an asset.

- Barriers to PV development include: uncertainty about the future of the solar market in New Jersey, and in particular, the future of the CORE program; intermittency and marginal amount of insolation; a silicon shortage; high upfront cost and inability to value system as an asset for purposes of project finance; need for stronger support for installer training.

- Barriers to biomass development include: the expense of fuel transport resulting from the fact that the fuel has low energy and volumetric density; the challenge of managing fuel supply needs due to inconsistencies in composition and moisture content of biomass fuel; an immature market for biomass supply, which results in unpredictable fuel costs and complicates project economics; and the length of the permitting and siting process.

- Barriers to landfill gas development include: difficulty in predicting a landfill's fuel supply resource (because the fuel resource depends on what was disposed at the landfill, and it declines

[61] Based on CORE program records as of December 5, 2006.

over time at a rate that can be difficult to predict); and limited number of remaining landfills suitable for power generation.

- Barriers to wind energy development include: a lack of onshore wind resource; siting and permitting; large upfront and levelized costs; intermittency and unpredictability of wind resource; uncertainty regarding long-term availability of production tax credit.

- One of the largest overall barriers to all renewable energy development is the uncertainty associated with renewable energy market incentives and future REC values.

- Given the current market structure, economic, logistical and political factors would make it difficult for the BPU to coordinate with distribution companies to identify the best locations for distributed generation.

- A variety of options exist to link the BPU’s programs with efforts to increase energy efficiency at participating facilities including a requirement that all program participants complete an energy audit, or incentive adders to encourage participants to complete energy saving measures.

2.6.2 Recommendations

- Establish an incentive system that lenders and equity owners can count on over a reasonable period into the future. This will resolve the issue of attracting financing to the state and will ameliorate the high capital and levelized costs associated with PV.

- Clearly communicate the state’s long-term commitment to developing the renewable energy market to avoid disillusionment and antipathy towards the state’s incentive programs as the state transitions to a more stable long-term system for market development.

- Offer a low or zero-interest financing service through the CORE program to help participants deal with the lag in timing of incentive payment, and to broaden the scope of potential program participants to include those in lower income brackets than current participants.

- Seek to identify geographically compact areas that can provide a sustainable biomass fuel supply.

- In order to increase the chances of meeting RPS requirements at a minimal cost to ratepayers, New Jersey should significantly increase efforts to encourage the development of utility-scale wind and biomass resources in addition to maintaining its commitment to PV market development.

- Require that all CORE program participants complete an energy audit in order to participate in the program. In addition, provide incentive adders for participants living in Energy Star homes, or those that complete significant energy efficiency measures.

3 PROGRAM LEVEL ASSESSMENT

Program level performance assessments were conducted for the SREC / Behind the Meter REC Trading Platform, the Customer Onsite Renewable Energy program (CORE), the Renewable Energy Project Grants and Financing program, and the Business Venture Assistance program. Each of these assessments included a review of performance indicators, as well as a review of the program's structural components and implementation-related issues. In addition, the Summit Blue team reviewed the potential for offering a PV manufacturer incentive program.

3.1 Review and Revise Program Indicators

One of the first tasks completed as part of the market assessment was a review of existing program performance indicators. A set of indicators was selected for each program that would provide insight into key areas of both program performance and overall market changes and effects. Each indicator is either related to a specific program/BPU goal or objective, or provides important information that can be used to track changes in market barriers and/or market maturity. Complete lists of indicators by program are included within each program-level assessment.

In addition to the indicators included in the program assessments discussed in this report, some indicators were identified that would be valuable to measure in the future. These indicators could not be included in the current assessment due to lack of available data or project timing constraints. Complete lists of indicators recommended for future measurement are included in Appendix B.

A summary of key indicator estimates for the period through 2006 is provided in Table 3-1.

Table 3-1. Summary of Key Indicator Estimates, CORE and Renewable Energy Project Grants and Financing[62]

Indicator	CORE	Project Grants and Financing
Number of processed applications	2,813	9
Number of completed (paid) projects	1,898	2
Number of days to process applications		
average from 2001-2006	35 days	initial application reviews, 30 days; complete evaluations, 60-120 days
2006 only	131 days[63]	N/A
Number of completed RE installations (by project size & RE type)	1,898[64]	
Solar	1,880	0
Wind	5	1
biomass / landfill gas	5	1
(fuel cells)	7	0
Installed Capacity (MW)	31.04 including fuel cells; 29.54 excluding fuel cells	6.5
Solar	27.33	0
Wind	0.04	4.875[65]
biomass / landfill gas	2.17	1.6
(fuel cells)	1.5	0
Installed Costs ($/kW, 2006)		

[62] All data are based on projects completed (paid) through December 31, 2006 and are excluding fuel cell data unless otherwise noted. This is due to the fact that fuel cells funded thus far have not been fueled by renewables and therefore are not RPS Class I eligible resources.

[63] This substantial increase in the length of time to process applications in 2006 was due to the Board's need to queue applications to avoid making more commitments than could be served by the budget. It does not indicate poor performance on the part of the application processing team. Because the value for 2006 was so much higher than for earlier years it is shown separately here.

[64] One project completed in 2006 is of unknown type. Therefore, the actual total number of projects is 1,898.

[65] Note that the REPGF program grant for the 7.5 MW Jersey Atlantic Wind / Community Energy wind farm was calculated based on 4.875 MW of installed capacity. 2.635 MW received funding under the CORE program in early 2007. Since only funded capacity is counted in this market assessment, and to properly attribute capacity development across programs, only 4.875 MW of the wind farm has been attributed to the REPGF program, and 2.625 MW should be attributed to the CORE program in a future market assessment. However, since the full 7.5 MW project has been operational since the end of 2005, its total capacity and output have been counted in the market level assessment (using 2006 as the starting year since that was the year in which the project received its first incentive payment).

Indicator	CORE	Project Grants and Financing
Solar	$7,901	N/A
Wind	$7,172	$1,280
biomass / landfill gas	$3,232	$2,420
(fuel cells)	$6,193	N/A
Total incentives paid	$126,875,301	$686,984
Annual generation from systems (MWh)		
Solar	26,422	0
Wind	49	13,967
biomass / landfill gas	13,071	12,516
(fuel cells)	9,855	0
Total	49,397 including fuel cells 39,542 excluding fuel cells	26,483
Cumulative avoided CO_2 emissions (metric tons)	49,227[66]	26,884
Estimated annual electricity cost savings for participants	$4,509,292[67]	N/A

3.2 CORE Program Performance Assessment

3.2.1 Introduction

New Jersey's Customer On-Site Renewable Energy program (CORE) began in 2001. From 2001 to mid-2003, this program was managed by the Electric Distribution Companies (EDCs). After mid-2003, the program was managed by the New Jersey Board of Public Utilities' Office of Clean Energy (BPU). Rebates are provided to participants who install qualifying solar electric, fuel cell, biomass, or wind projects.

[66] Figure excludes fuel cells.

[67] Figure excludes fuel cells.

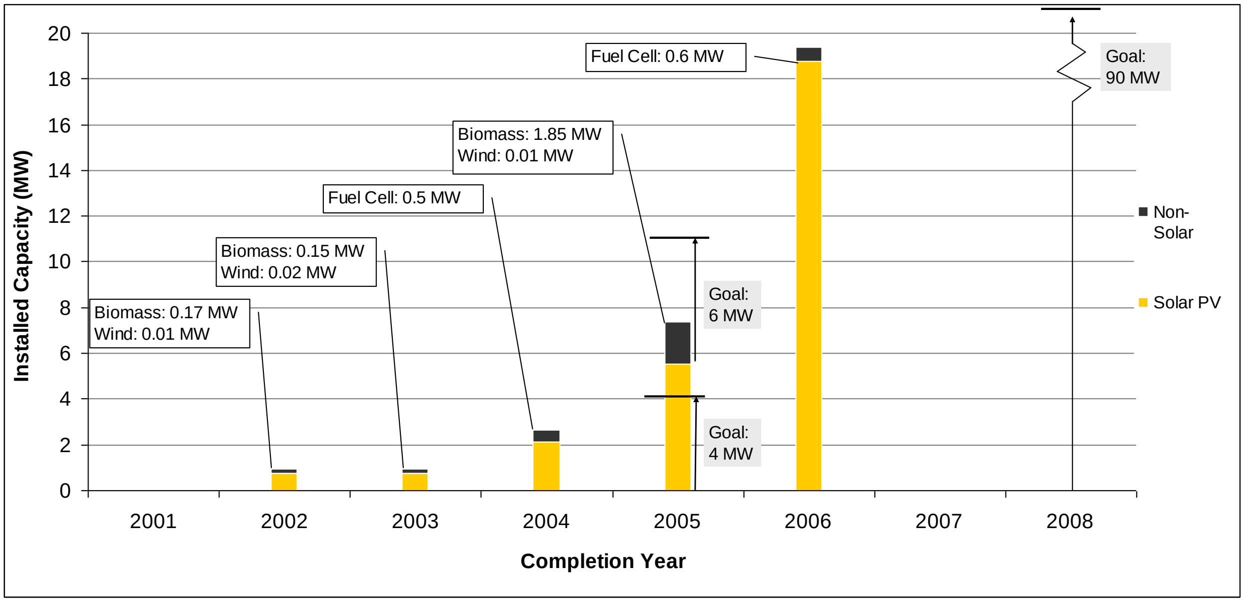
3.2.2 Summary of Goals and Achievements

CORE PROGRAM OBJECTIVES[68]	STATUS	ACHIEVED GOAL?
Process 600 applications in 2005.	1,219 applications were processed in 2005. 496 rebate payments were issued in 2005.	Yes
Install 4 MW of PV systems in 2005.	5.5 MW of PV capacity was installed in 2005.	Yes
Install 6 MW of other (non-solar) RE systems in 2005.	1.9 MW of biomass and wind capacity were installed in 2005.	No
Process initial applications for rebate funding in 30 days.	Initial applications were processed in less than 30 days in 2002-2005. The average processing time for 2002-2006 was 35 days.	See status comments
Process applications from final application to QC inspection in 14 days.	The average was one day for 2003-2006 due to negative process times recorded in database[69]	Yes
Process applications from QC inspection to rebate check in 30 days.	The average was 63 days for 2003-2006.	No

[68] Goals are specified in “New Jersey’s Clean Energy program 2005 program Descriptions and Budgets,” June 9, 2005.

[69] The elapsed time from receipt of final application to date of inspection has been tracked here because one of the program implementation goals set forth in the 2005 OCE Compliance Filing was "Perform QC inspections within 14 days of receipt of final application." However, program staff report that the program has not implemented any policies or procedures linking the timing of receipt of final application to timing of the inspection. Therefore, many systems have been inspected before the receipt of the final application form and vice versa, accounting for the many instances of negative elapsed time between receipt of final application and inspection.

Figure 3-1. Summary of CORE Program Project Development through 2006



3.2.3 Program Performance Indicators

The CORE program indicators are listed below.

1. Number of applications received
2. Number of applications processed
3. Number of participating RE installations
4. Number of unique end-use customers/participants
5. Distribution of end-use customer facility types
6. Number of unique installation contractors by RE type
7. Number of incentives/rebates processed
8. Cumulative annual dollar value of incentives/rebates processed
9. Estimated annual electricity cost savings for participants
10. End-use customer awareness of program
11. Extent to which program participation influenced end-use customer awareness of RE
12. Extent to which program participation influenced end-use customer confidence in RE technologies
13. End-use customer perceptions of installation quality

14. RE capacity installed, by year
15. Annual RE generation from participating RE systems
16. Cumulative avoided environmental impacts
17. Number of days to process applications
18. Average installed costs by technology

The indicators, the relationship to the program-specific or overall BPU goals, and the results from the analysis are shown below.

Indicator #1: Number of applications received

Indicator #2: Number of applications processed

Indicator #7: Number of incentives/rebates processed

Relationship to program-Specific Goals: Process 600 applications in 2005.

The goal to process 600 applications in 2005 was exceeded; 1,219 applications were processed during that year. Also in 2005, the CORE program processed 496 incentives (Table 3-2).

Table 3-2. Number of Applications Received and Processed, and Number of Incentive Processed

Year	Number of Applications Received	Number of Applications Processed	Number of Incentives Processed
2001	1	-	6
2002	2	1	46
2003	213	226	61
2004	616	585	284
2005	1,296	1,219	496
2006	2,141	782	1,005
Total	4,269	2,813	1,898

Notes:

** Some applications have a date for approval letter and no date for the application received.*

*** "Number of program Applications" is matched with the application year, "Number of Processed Applications" is matched with the approval year, and "Number of Incentives/Rebates PrBPUssed" is matched with the completion year.*

**** The latest program application was received on October 21, 2006; the latest processed application was received on November 16, 2006; and the incentives are processed as of December 31, 2006.*

***** The 'Number of Incentives Processed' includes data from 2001-mid-2003; this data is unavailable for 'Number of program Applications' and 'Number of Processed Applications.'*

Indicator #3: Number of participating RE installations

Relationship to program-Specific Goals: Install 4 MW of PV systems in 2005; Install 6 MW of other RE systems in 2005.

In 2005, the participating renewable energy installations included solar electric, biomass, and wind. The number of participating solar electric installations nearly doubled from 2004 to 2005 and from 2005 to 2006 (Table 3-3). The majority of renewable energy installations were between 6-10 kW in size.

Table 3-3. Number of Participating Renewable Energy Installations[70]

Completion Year	Solar Electric	Fuel Cell	Biomass	Wind	Total by Year
2001	6	-	-	-	6
2002	42	1	1	2	45
2003	56	1	2	2	60
2004	282	2	-	-	284
2005	493	-	2	1	496
2006	1,001	3	-	-	1,005
Grand Total processed as of 12/31/06	1,880	7	5	5	1,897*

**One project in 2006 is of unknown type. Therefore, the actual total number of projects is 1,898.*

Indicator #4: Number of unique end-use customers/participants

Relationship to program-Specific Goals: Process 600 applications in 2005.

The number of unique end-use participants increased over time from 2003 to 2006, and totaled 1,744 through 2006. Of the 496 incentives processed in 2005, 480 of those participants were unique (Table 3-4). Data on the number of processed applications is unavailable for 2001 and 2002, and therefore the number of unique participants in those years could not be determined.

[70] The number of participating renewable energy installations includes both data from the NJCEP website and the CORE program database. For mid-2003 through 2006 projects, only projects that have received a check are included. Note that fuel cells are not included on the NJCEP website.

Table 3-4. Number of Unique End-Use Participants

Completion Year	Number of Unique End-Use Participants
2003	34
2004	267
2005	480
2006	963
Total	1,744

Indicator #5: Distribution of end-use customer facility types

Relationship to program-Specific Goals: Process 600 applications in 2005

The distribution of end-use customer facility types (excluding fuel cell projects) are contained in Table 3-5 and

Table 3-6. The majority of end-use customer facility types are residential customers comprising 78% of the total applications and 86% of the total incentives processed. Commercial facilities (which include industrial facilities) account for 16% of program applications and 11% of incentives. Schools and universities make up a small percentage of applications (about 2.6 percent) and have only received about 1.7 percent of the program incentives. The commercial and non-residential sectors comprise 62%[71] of total installed capacity while the residential sector comprises 38% of the total installed capacity.

[71] Total non-residential / commercial percentages do not add to 62% in the table due to rounding.

Table 3-5. Distribution of End-Use Customer Facility Types[72]

Customer Type	Percent of Total Applications Received	Percent of Total Incentives Processed	Percent of Total Installed Capacity
Residential	78%	85.5%	38%
Commercial	16%	10.5%	40%
Government	2%	0.6%	5%
School public k-12	2%	1%	11%
Non Profit	1%	1.6%	1%
Municipality	0.3%	-	-
School other	0.3%	0.3%	-
University Public	0.2%	0.3%	2%
University Private	0.1%	0.1%	2%
Total processed as of 12/31/06	100%	100%	100%

Table 3-6. Distribution of End-Use Participant Types (by Residential, Commercial, and Institutional only)[73]

Customer Type	Percent of Total Applications	Percent of Total Incentives Processed	Percent of Total Installed Capacity
Residential	78%	86%	38%
Commercial	16%	10%	40%
Institutional*	5%	4%	22%
Total processed as of 12/31/06**	100%	100%	100%

[72] Data obtained from CORE database. The database does not include project records for 2001 through mid-2003. Therefore, the systems installed during that time are not reflected here. Program records which were provided for the 2001 through mid-2003 period do not include data on customer type.

[73] As with the previous table, the data in this table does not include projects completed from 2001 through mid-2003.

Indicator #6: Number of unique installation contractors by RE type

Relationship to program-Specific Goals: Install 4 MW or PV systems in 2005; Install 6 MW of other RE systems in 2005.

The number of unique contractors installing solar electric in the CORE program has increased from 2003 to 2006. Only a few contractors have installed fuel cell, biomass or wind projects (Table 3-7).

Table 3-7. Number of Unique Installation Contractors by Renewable Energy Type

Completion Year	Solar Electric	Fuel Cell	Biomass	Wind
2003	15	1	-	-
2004	41	1	-	-
2005	51	-	1	1
2006	70	1	-	-

Indicator #8: Cumulative annual dollar value of incentives/rebates processed

Relationship to program-Specific Goals: Process 600 applications in 2005.

Table 3-8 shows the cumulative annual dollar value of the incentives processed. The cumulative annual dollar amount of incentives processed has increased from 2001 to 2006 as the number of applications has increased over time. The total amount of incentive payments processed for projects that were completed by December 31, 2006 was $131,557,613, including fuel cell projects. Excluding fuel cell projects, the total amount of incentives paid was $126,875,301.[74]

[74] None of the fuel cells installed through the CORE program run on renewable fuels. Therefore, none of the fuel cell generation can be used for RPS compliance. Therefore, data with and without fuel cell projects is presented.

Table 3-8. Cumulative Annual Dollar Value of Incentive Processed[75]

Completion Year	Cumulative annual dollar value of incentives/rebates processed- Including Fuel Cell Projects	Cumulative annual dollar value of incentives/rebates processed- Excluding Fuel Cell Projects
2001	$45,750	$45,750
2002	$3,967,140	$3,257,140
2003	$4,292,630	$3,582,630
2004	$12,604,767	$10,917,455
2005	$29,158,326	$29,158,326
2006	$81,489,000	$79,914,000
Total processed as of 12/31/06	$131,557,613	$126,875,301

Indicator #9: Estimated annual electricity cost savings for participants

The annual estimated electricity cost savings for participants also increased from 2001 to 2006, as the number of systems going on-line has increased (Table 3-9).

Table 3-9. Estimated annual electricity cost savings estimates for participants[76]

Year	Estimated annual electricity cost savings for participants- Including Fuel Cell Projects	Estimated annual electricity cost savings for participants- Excluding Fuel Cell Projects
2001	$975	$975
2002	$305,905	$181,569
2003	$602,182	$350,352
2004	$1,042,617	$508,039
2005	$2,797,857	$2,235,203
2006	$5,555,779	$4,509,292

[75] The cumulative annual dollar value of incentives processed includes both data from the NJCEP website and the CORE program database. For mid-2003 through 2006 projects, only projects that have received a check are included. Note that fuel cells are not included on the NJCEP website. It is assumed that fuel cell projects are included in the New Jersey Clean Energy program- YTD 4th Quarter 2006 Report because fuel cell values are included in the CORE database on which the quarterly report was based.

[76] The estimated annual electricity cost savings include both data from the NJCEP website and the CORE program database. For mid-2003 through 2006 projects, only projects that have received a check are included. Note that fuel cells are not included on the NJCEP website. These savings are cumulative by year because projects continue to deem savings in all years after the year of installation. The cost savings for 2006 are equal to the savings in 2005 plus the estimated savings from the 2006 generation values in the New Jersey Clean Energy program- YTD 4th Quarter 2006 Report. These estimated savings assume that 62% of the generation is in the commercial sector and 38% of the generation is in the residential sector, based on the installed capacity values. Note that one fuel cell project received a rebate in 2004, but is assumed to go online in 2003.

Indicator #10: End-use customer awareness of program

From the CORE participant survey, 81% of respondents indicated that they self-initiated the development of their system, while 19% were approached by a renewable energy company or contractor. Twenty-four percent of the respondents found out about the CORE program through word of mouth. Other key sources of information about the CORE program were “Renewable energy systems company or contractor” (19%) “internet” (11%) and “an article in a newspaper or newsletter” (10%). Non-participants were not surveyed. Therefore, awareness of the program among the general public cannot be fully assessed. However, based on the survey results described above (i.e., 10% found out about the program through a newspaper or newsletter, and 81% of respondents’ projects were self initiated), one may assume that the level of awareness ***among the general public*** is fairly low, and that a substantial number of participants to date have been early adopters who are more likely to seek out information about renewable energy incentives than the general public.

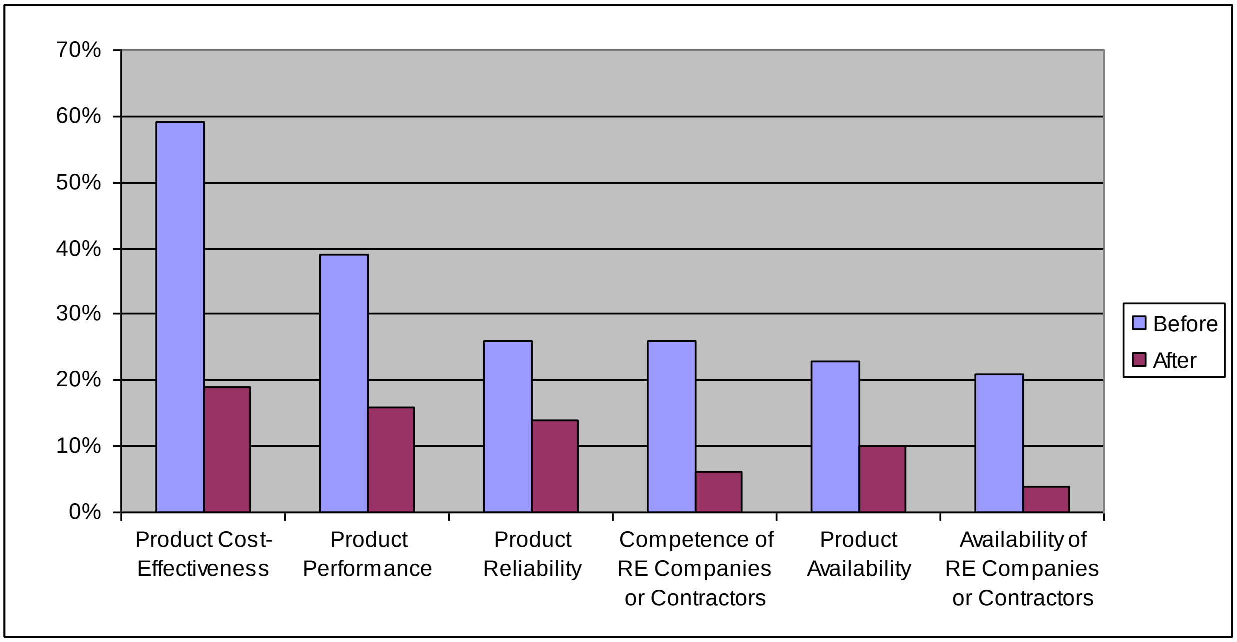
Indicator #11: Extent to which program participation influenced end-use customer awareness of renewable energy

The majority of respondents (86%) from the CORE participant survey had no experience with any type of renewable energy system before their participation in the CORE program. Many participants (66%) were not planning to install a renewable energy system before they learned about the program. Based on the survey responses, the program seemed to influence many end-use customers’ awareness of renewable energy.

Indicator #12: Extent to which program participation influenced end-use customer confidence in renewable energy technologies

Figure 3-2 shows the results from the CORE participant survey summarizing the responses of participants when asked if they were significantly concerned about particular issues before or after they installed their system.

Figure 3-2. Percent of Participants Stating Concern about Issues Before and After Program Participation



As indicated in Figure 3-2, participants were more concerned about product and other renewable technology issues before participating in the CORE program than after participating. Respondents also listed what they considered to be major barriers to installing a renewable energy system. The top three barriers reported by respondents were "first costs" (54%), "structural limitations of building" (30%) and "specific program requirements" (19%). Respondents were then asked to indicate, using a scale from one to five, their thoughts on how effective the CORE program is in reducing these barriers. A summary of these responses is shown in

Table **3-10**.

Table 3-10. Participant Opinions on Program Effectiveness at Reducing Barriers

How effective is the New Jersey CORE program in reducing barriers?	
1= Very Ineffective	6%
2	10%
3	37%
4	27%
5= Very Effective	1%
Don't know	7%
n/a	4%
Refused	7%

These survey results show that participants believe the CORE program was somewhat effective at reducing barriers. Responses to both survey questions discussed here indicate that program participation did increase customer confidence in renewable energy technologies.

Indicator #13: End-use customer perceptions of installation quality

The majority of respondents from the CORE participant survey were very satisfied with their system's performance (Table 3-11).

Table 3-11. Participants' Satisfaction with RE System Performance

Satisfaction with RE system's performance so far, compared to expectations	
1= Very Unsatisfied	0%
2	3%
3	10%
4	23%
5= Very Satisfied	64%

However, 16% of respondents reported having experienced significant failures of the system or its components. The majority of failures were cited as being inverter failures. Also, 13% of respondents have had concerns about future technical support for their system. Many of these concerns centered on warranty issues, especially with the lifetime of the warranty, and on issues about having a reliable contact if a problem with their system occurred. As New Jersey considers transitioning to a more performance based incentive program structure, consideration of the level of installation quality occurring under the current CORE rebate program is important.

Indicator #14: Renewable energy capacity completed, by year

Relationship to Goals (Both BPU and program-Specific): By December 31, 2008, install (complete) 300 MW of Class I renewable energy generation capacity in NJ, of which a minimum of 90 MW should be from PV. Install (complete) 4 MW of PV systems in 2005. Install (complete) 6 MW of other RE systems in 2005.

Note that for the purposes of maintaining consistency in program evaluation and monitoring methods, programs have been evaluated based on the amount of installed capacity that has *received incentive payment* as of the end of 2006. These projects are described as "completed" throughout this report. In some cases, additional capacity has been installed, but has not received payment, and therefore is not included in the values presented in this assessment.

As of October, 2006, approximately 30 MW of renewable energy capacity has been completed under the CORE program (Table 3-12). The goal for New Jersey is to install (complete) 300 MW of Class I renewable energy generation capacity by December 31, 2008. Therefore, the CORE program has contributed approximately 10 % toward achieving this goal.

Program participants completed 5.5 MW of solar electric system capacity during 2005, surpassing the BPU's 4 MW goal for 2005 by about 38%. The goal of completing 6 MW of other renewable energy systems in 2005 was not reached. Under the CORE program, only 1.9 MW of other renewable energy systems, biomass and wind, were completed in 2005. Therefore, about 32% of the non-solar renewable energy target was achieved in 2005.

Table 3-12. Renewable Energy Capacity Completed by CORE Participants, by Technology Type and by Year (MW)[77]

Completion Year	Solar Electric	Biomass	Wind	Fuel Cells	Total Including Fuel Cell Projects	Total Excluding Fuel Cell Projects
2001	0.01	-	-	-	0.01	0.01
2002	0.76	0.17	0.01	0.2	1.14	0.94
2003	0.76	0.15	0.02	0.2	1.13	0.93
2004	2.14	-	-	0.5	2.64	2.14
2005	5.53	1.85	0.01	-	7.39	7.39
2006	18.13	-	-	0.6	18.73	18.13
Total processed as of 12/31/06	27.33	2.17	0.04	1.5	31.04	29.54

Indicator #15: Annual RE generation from participating RE systems

Renewable energy generation from CORE projects is shown in Table 3-13 and Table 3-14. Annual renewable energy generation for only the year that the projects received the rebate is shown in Table 3-13, and cumulative energy generation by year is shown in Table 3-14. In 2006, a total of 22,470 MWh were generated from projects that received a rebate in 2006; about 49,396 MWh were generated in 2006 from all projects that were online including fuel cells, and about 39,541 MWh were generated in 2006 from all projects that were online excluding fuel cell projects. The BPU goal by the end of 2008 is to have 6.5% of electricity in New Jersey provided by Class I or Class II renewables, and 4% of Class I resources from solar. Using EIA retail sales data, the Summit Blue team estimates that the sales in 2008 will be about 85,637 GWh. Generation from CORE program Class I resources (does not include fuel cells) completed through the end of 2006 (39,541 MWh, shown in Table 3-14) amounts to approximately 0.05 percent of retail sales projected for 2008. The CORE generation values will be combined with those from projects funded through the Renewable Energy Project Grants and Financing program and other Class I renewable energy generation in the state to determine the BPU's ability to meet its generation goals for 2008.

[77] The annual renewable energy capacity includes both data from the NJCEP website and the CORE program database. For mid-2003 through 2006 projects, only projects that have received a check are included. Note that fuel cells are not included on the NJCEP website.

Table 3-13. Electricity Generation Estimates for Year of Completion, by Technology Type (MWh)[78]

Year	Solar Electric	Biomass	Wind	Fuel Cells	Total Including Fuel Cell Projects	Total Excluding Fuel Cell Projects
2001	11	-	-	-	11	11
2002	870	1,024	14	1,314	3,222	1,908
2003	792	920	26	1,314	3,052	1,738
2004	1,335	-	-	3,218	4,553	1,335
2005	3,260	11,127	8	-	14,395	14,395
2006	18,528	-	-	3,942	22,470	18,528

Table 3-14. Total Annual Electricity Generation Estimates, by Technology Type[79] (MWh)

Year	Solar Electric	Biomass	Wind	Fuel Cells	Total Including Fuel Cell Projects	Total Excluding Fuel Cell Projects
2001	11	-	-	-	11	11
2002	880	1,024	14	1,314	3,233	1,919
2003	1,672	1,944	41	3,042	6,699	3,657
2004	3,125	1,944	41	5,846	10,956	5,110
2005	7,893	13,071	49	5,913	26,926	21,013
2006	26,421	13,071	49	9,855	49,396	39,541

Indicator #16: Cumulative avoided environmental impacts

From renewable energy installations under the CORE program through 2006, approximately 67,170 metric tons of carbon dioxide, 287 metric tons of sulfur dioxide, 124 metric tons of nitrous oxides,

[78] Table 3-13 shows the generation for only projects that went online in the specified year. Data for 2006 is from the New Jersey Clean Energy program- YTD 4th Quarter 2006 Report. Data for 2006 is not split by renewable energy type because the report shows only a value for the total energy generated. The 4th Quarter 2006 Report data is based on data provided by Clean Power Markets, administrator of the SREC trading system. The data that Summit Blue Consulting received for the SREC market values differ for 2006. Capacity factor for fuel cells estimated at 0.75. The date of installation of the fuel cells completed in 2002 and 2003 is unknown; generation is assumed to begin at the beginning of the calendar year.

[79] The annual renewable energy generation includes both data from the NJCEP website and the CORE program database. For mid-2003 through 2006 projects, only projects that have received a check are included. Note that fuel cells are not included on the NJCEP website. These generation values are cumulative by year because projects continue to generate energy in all years after the year of installation.

and 0.002 metric tons of mercury emission will be avoided annually[80] (Table 3-15). Avoiding the emissions of 67,170 metric tons of carbon dioxide is equivalent to taking about 14,500 passenger cars off the road for one year. It is important to recognize that renewable energy generation is not likely to reduce aggregate emissions of criteria air pollutants covered under cap and trade programs (NOx, SOx).[81]

Table 3-15. Cumulative Avoided Environmental Impacts (Estimates)

	Environmental Impacts Including Fuel Cells		Environmental Impacts Excluding Fuel Cells	
	2006 (metric tons)	2001 through 2006 (metric tons)	2006 (metric tons)	2001 through 2006 (metric tons)
CO_2	15,525	67,170	12,801	49,227
SO_2	66	287	55	211
NOx	29	124	24	91
Hg	0.0004	0.002	0.0003	0.001

Indicator #17: Number of days to process applications

Relationship to program-Specific Goals: Process initial application for rebate funding in 30 days; Perform QC inspections within 14 days of receipt of final application; Issue rebate checks within 30 days.

The goal to process the initial application for rebate funding in 30 days was achieved for 2002-2005, but not for 2006. Across all years since program inception, the average number of days to process the initial application was 35 days (Table 3-16). This substantial increase in the length of time to process applications in 2006 was due to the Board's need to queue applications to avoid making more commitments than could be served by the budget. It does not indicate poor performance on the part of the application processing team.

[80] US Climate Technology Cooperation Gateway, Greenhouse Gas Equivalencies Calculator. http://www.usctcgateway.net/tool/.

[81] Chen, Cliff, Ryan Wiser, and Mark Bolinger. "Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections," Environmental Energy Technologies Division. LBNL-61580. March 2007.

Table 3-16. Average Number of Days to Process Applications From Pre-Installation To Approval Letter

Approval Year	Days
2002	1
2003	14
2004	17
2005	11
2006	131
Average of All Years	35

The goal to perform the inspection within 14 days of the receipt of final application was met and exceeded for all years except 2003 (

Table 3-17). For many applications, the inspection was completed before the final application was logged into the database as completed. The goal to complete inspections within 14 days of receipt of final applications has been tracked here because it is specifically stated as a program goal in the 2005 OCE Compliance Filing. However, program staff report that the program has not implemented any policies or procedures linking the timing of receipt of final application to timing of the inspection. Therefore, many systems have been inspected before the receipt of the final application form and vice versa, accounting for the many instances of negative elapsed time between receipt of final application and inspection.

Table 3-17. Average Number of Days to Process Applications from Final Application to QC Inspection

Completion Year	Days
2003	16
2004	1
2005	-14
2006	-1
Average of All Years	1

The goal to issue rebate checks within 30 days was not met in any of the program years. Across all years included in the database, the average application processing time from the inspection to issuance of a check was 63 days (Table 3-18).

Table 3-18. Average Number of Days to Process Applications from QC Inspection to Check

Completion Year	Days
2003	57
2004	49
2005	66
2006	81
Average of All Years	63

Indicator #18: Average installed costs by technology

Average installed costs for the technologies eligible for incentives in the CORE program are shown in Table 3-19. The values are based on projects receiving funding through the program through 2006. Wind is shown as the technology with the highest cost, though this value is based on only one project. Biomass projects have the lowest installed costs, with fuel cells following.[82] The cost effectiveness for the technologies is also shown in Table 3-19 as the average incentive paid per installed watt. These values show that the CORE program has spent the most on residential solar projects ($5.21/W) and the least on biomass projects ($1.29/W). On average, solar projects cost about 1.5 times more than non-solar projects.

Table 3-19. Average Installed Costs by Technology

Technology	Average Installed Cost ($/Wdc)	Average Incentives/Installed Watt ($/Wdc)	Percentage of installed cost from Incentive
Solar PV- Residential	8.02	5.21	65%
Solar PV- Commercial	7.80	3.90	50%
Biomass	3.23	1.29	40%
Fuel Cell	5.94	2.97	50%
Wind	8.34	5.00	60%

Source: CORE program database

The only technology with enough installations under the CORE program to show trends over time is PV. 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 3-20 and Figure 3-3). The decline in costs over this period may be due to project developers working out delivery efficiencies and a result of increased competition among PV project developers. Program staff note that a more substantial contributor to the cost decline over this period was probably was the change in CORE rebate calculation

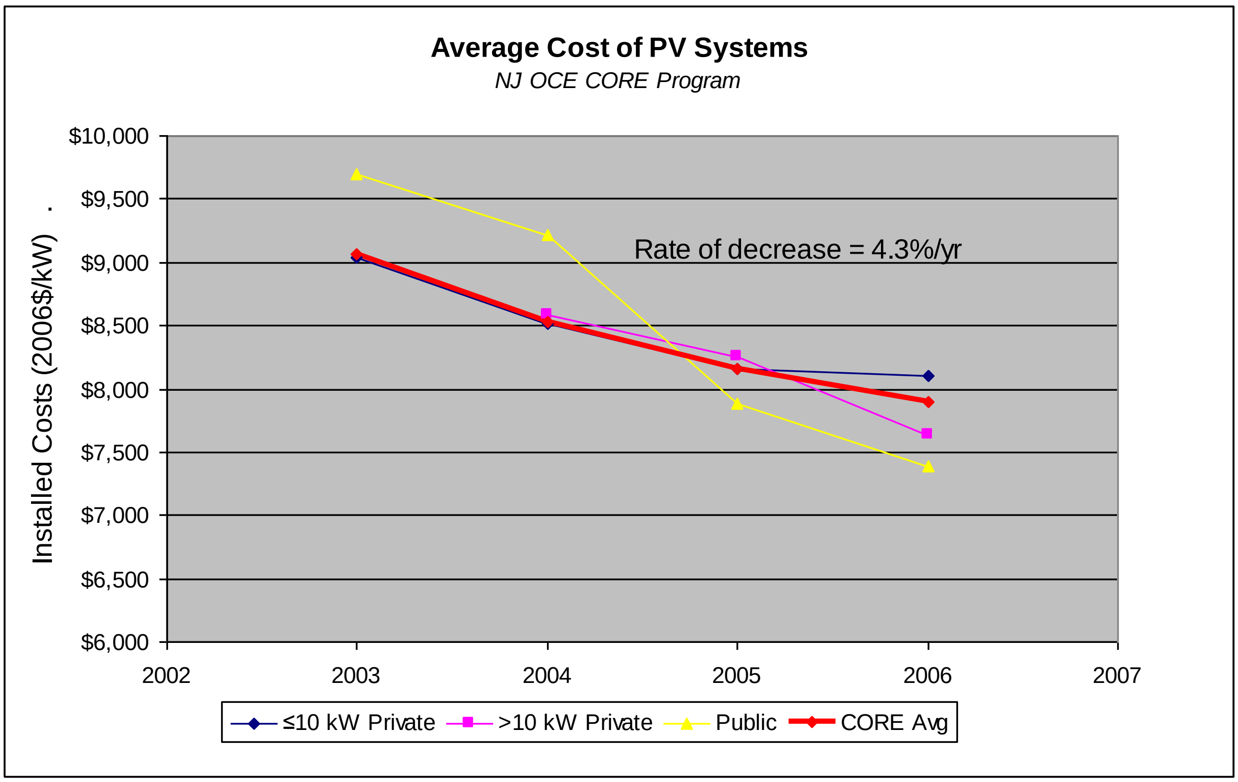
[82] Based on five fuel cell project records that varied substantially. Fuel cell costs may be higher than reported here.

methodology in June 2005.[83] However, the decrease in costs were fairly gradual and consistent over time, with the largest percentage decrease occurring from 2003 to 2004 (5.9% decline) and the smallest percentage decrease occurring from 2005 to 2006 (3.2% decline).

Table 3-20. 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 3-3. Average Cost of PV System in CORE Program (2006$/kW)



[83] Previously, the rebate was based upon the lesser of $5.50 per watt or 70% of total installed costs whichever was less, causing installers to set their total installed costs at $7.90 per watt. Effective July 1, 2005, incentives were issued based on rated capacity with no link to installed costs.

3.2.4 Assessment of CORE Program Structure and Implementation

The CORE program structure and implementation is discussed within the following sections:

- Program Delivery Review
- Program Management Assessment
- Marketing Assessment

Program Delivery Review

This section includes a review of the current status of the New Jersey Customer On-Site Renewable Energy (CORE) program, including the program process, program applications, program rebate levels, program impacts on system costs and infrastructure, preferred incentive mechanisms, incentive caps and barriers to program participation.

The technologies that are currently eligible for funding under the CORE program are solar photovoltaic, biomass, fuel cell, and wind technologies. Rebate amounts for the CORE program are shown in Table 3-21 and Table 3-22.[84] Rebate applications for private sector projects are currently being held in a queue and rebate commitment approvals are issued as funding becomes available.[85] As of August, 2007, funding requests from solar PV private sector projects in the queue amount to $97.9 million, while no private sector biomass, fuel cell or wind projects were in the queue. Funding is available for public sector projects, including non-schools, schools K-12, and SUNLIT projects,[86] and the funding amounts to about $8 million.[87]

[84] Note that rebate levels for PV systems changed on September 1, 2007. However, because this change occurred after the analysis period for this assignment, earlier rebate levels are shown here.

[85] Rebate payment is being honored for all commitment approvals made.

[86] The SUNLIT program is offered through the New Jersey Housing and Mortgage Finance Agency.

[87] NJ Clean Energy program. Updated 2007 CORE Budget (April 10, 2007). http://www.njcep.com/media/CORE%20Status%20Report%20041007.pdf. Data valid as of April 10, 2007. The SUNLIT program is offered through the New Jersey Housing and Mortgage Finance Agency.

Table 3-21. Wind and Sustainable Biomass Rebate Levels for the CORE Program

Wind and Sustainable Biomass Systems	
2006	**Incentive Level**
Systems up to 10 kW	$5.00/W
Maximum incentive as percentage of eligible system costs	60%
Systems Greater than 10 kW	
1 - 10 kW	$3.00/W
> 10 to 100 kW	$2.00/W
> 100 to 500 kW	$1.50/W
> 500 kW, up to 1000 kW	$0.15/W
Maximum incentive as percentage of eligible system costs	30%

Source: NJ CORE program Web site. http://www.njcep.com/html/2_incent.html

Table 3-22. Solar PV Rebate Levels for the CORE Program (effective through 8/31/07)

Solar Electric Systems		
2006	**All Private Sector Applicants effective 9/01/06**	**All Public and Non-profit Applicants effective 9/01/06**
1 - 10 kW	$3.80/W	$4.40/W
> 10 – 40 kW	$2.75/W	$3.45/W
> 40 – 100 kW	$2.50/W	$2.80/W
> 100 – 500 kW	$2.25/W	$2.60/W
> 500 – 700 kW	$2.00/W	$2.05/W

Source: NJ CORE program Web site. http://www.njcep.com/html/2_incent.html

Policies and procedures for the CORE program include:[88]

- The rebate for CORE applicants purchasing electricity under a residential tariff is limited to the first 10kW of project capacity. Exemptions are available for farmers, non-profit organizations, houses of worship, and multi-family dwellings.

[88] Source: CORE program Update, August 17, 2006, http://www.njcep.com/media/COREprogramUpdate081706.pdf. and program Application form: http://www.njcep.com/html/4_app_eforms.html

- Eligible systems should be sized to produce no more than 100 percent of the historical or expected (if new construction) amount of electricity consumed at the system's site.

- Public sector applicants who plan to use the Federal Investment Tax Credit must apply under the private sector rebate level.

- Appeals can be made to the Office of Clean Energy.

- When sufficient funds do not exist in a budget category, projects will be placed in a queue.

- The Board has eliminated the 90 day grace period for submission of executed contracts for private sector projects greater than 10kW.

- Solar PV arrays must achieve a calculated system output of at least 80 percent of the default output estimated by PVWatts and strings must be at least 70 percent of the default output calculated by PVWatts.

- Installers must document anticipated project start dates, completion dates, and verify the adequacy of solar module supplies.

Policies and Procedures from the program Application Form:

- The system must be installed in New Jersey.

- System must be installed in accordance with requirements specified in the New Jersey Clean Energy program Technical Worksheet for that type of equipment (i.e., solar electric, wind or biomass), and it must come with owner’s manuals and warranty documentation.

- Only new equipment is eligible for rebates.

- System warranty must be all-inclusive for at least 5 years.

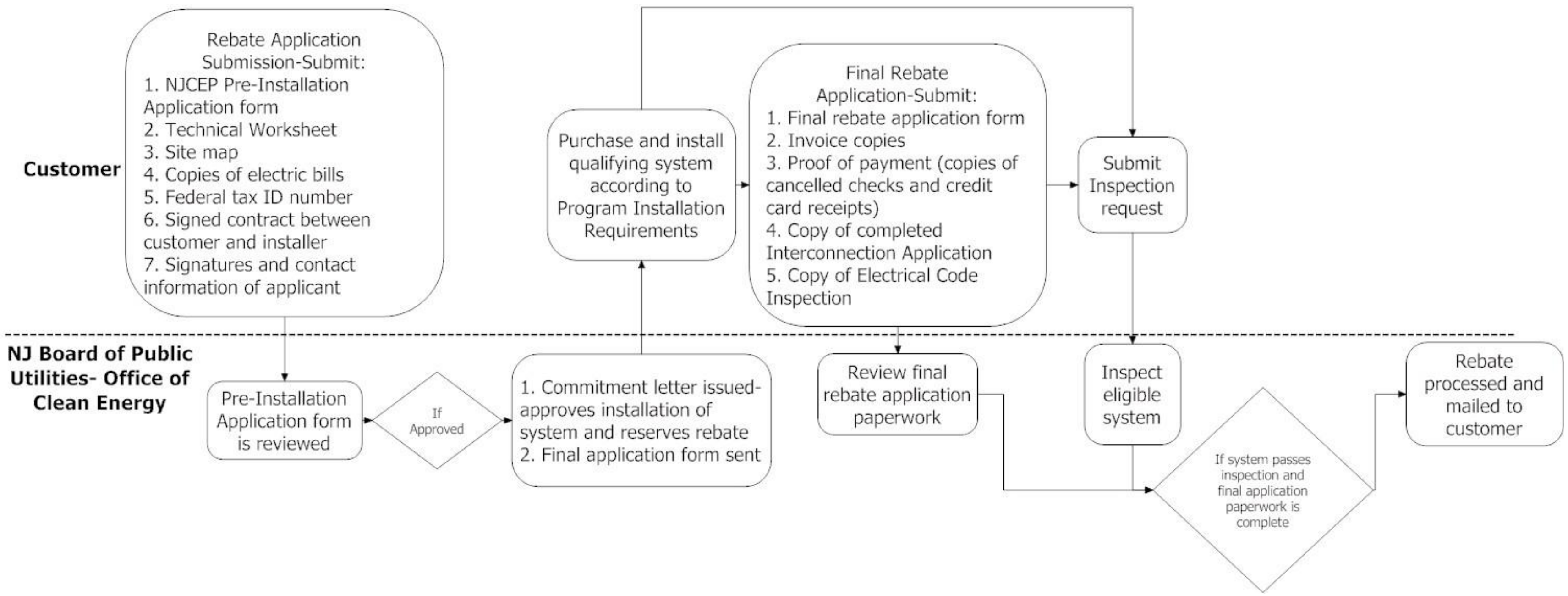
- Customer must receive a letter of rebate commitment from the New Jersey Board of Public Utilities (BPU) prior to installation. Equipment must be installed within a predetermined time period as specified in the commitment letter.

- Rebates will not be processed without a Federal Tax Identification number, Contracts, and authorized signatures from the Applicant and Installer.

Program Process

The CORE program process is shown below (Figure 3-4). The program process involves interaction between the customer and the NJ Board of Public Utilities- Office of Clean Energy. the BPU recently began outsourcing administration of the CORE program to a “market manager.” Honeywell currently holds the market manager contract, and sub-contractors from the Vermont Energy Investment Corporation and Conservation Services Group are directly responsible for administering the CORE program.

Figure 3-4. NJ CORE Program Process[89]



CORE Program Process Flow:

1. The BPU has 30 days to review the Pre-Installation Application and issue a commitment letter to the applicant.

[89] The timeframe specified in the NJ CORE program Process is from CORE program Update, August 17, 2006, http://www.njcep.com/media/COREprogramUpdate081706.pdf. and the CORE program goals. Note that for a significant portion of the period during which BPU administered the CORE program, the rebate was based upon the lesser of $5.50 per watt or 70% of total installed costs whichever was less, causing installers to set their total installed costs at $7.90 per watt. Effective July 1, 2005, incentives were issued based on rated capacity with no link to installed costs and invoice copies and proof of payment were no longer required for rebates applications submitted after this point.

2. Time frames once the applicant receives the commitment letter to submit the final rebate application paperwork:

    a. All systems less than 10 kW: 9 months with no extensions

    b. Private systems greater than 10 kW: 12 months with a 6 month extension possible

    c. Public systems greater than 10 kW: 12 months with a 12 month extension possible and a subsequent 6 month extension possible

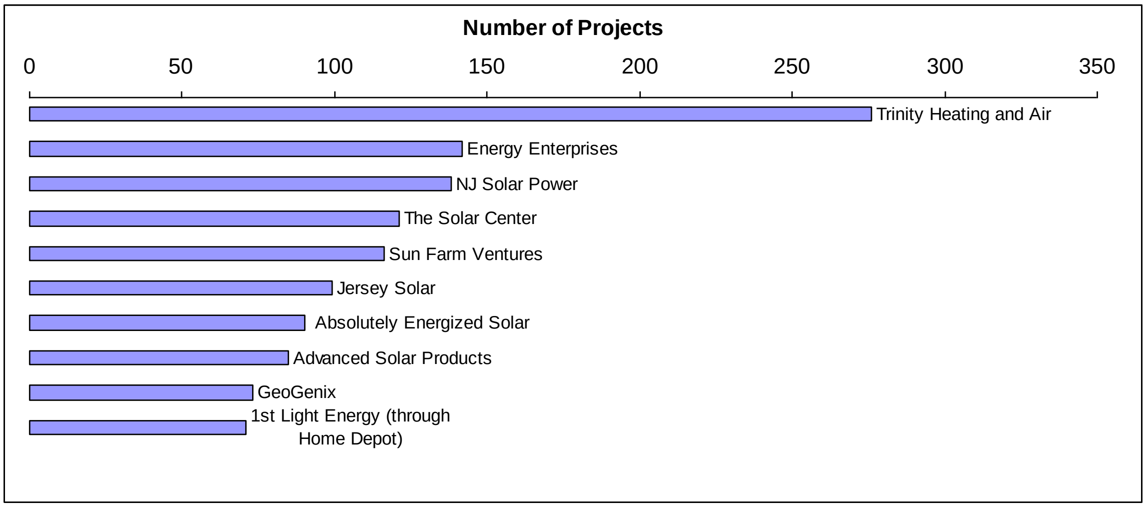
3. A goal set forth for the program in the 2005 OCE compliance filing was for BPU to perform the inspection within 14 days of the receipt of final application. While program staff did not adhere to this goal specifically, the intent of the goal was fulfilled. Program staff allowed inspections to occur after the system installation was complete regardless of whether final application paperwork had been submitted.[90]

4. The goal is to issue rebate checks within 30 days of the inspection. However, developers mention that rebate checks are rarely issued within this time frame.

[90] OCE Compliance Filing, June 9, 2005.

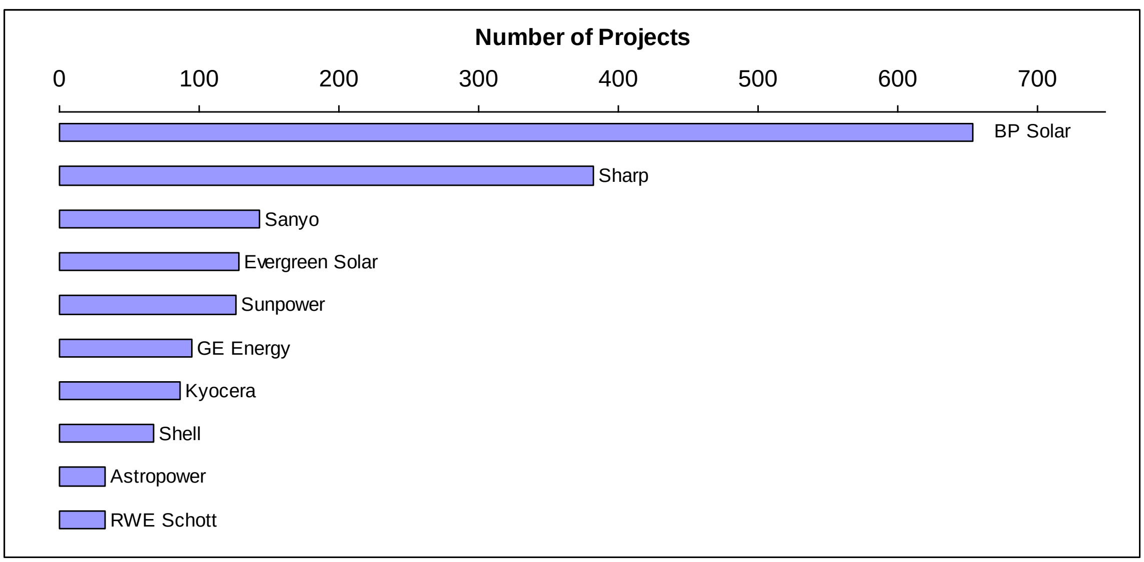
The top ten solar PV contractors and manufacturers involved with the CORE program, ranked according to number of installations, are shown in Figure 3-5 and Figure 3-6, respectively. The solar PV contractor that has completed the greatest number of installations is Trinity Heating and Air with almost twice the number of projects as second ranked contractor. BP Solar led the other manufacturers by a solid margin in terms of the number of projects completed through the program using the manufacturer's modules. Sharp was the second ranked manufacturer in terms of the number CORE installed systems using the company's modules. Sharp's modules were used in over twice as many projects as its closest competitor.

Figure 3-5. Solar PV Contractors in the CORE Program



Source: CORE program database

Figure 3-6. Solar PV Manufacturers in the CORE Program



Source: CORE program database

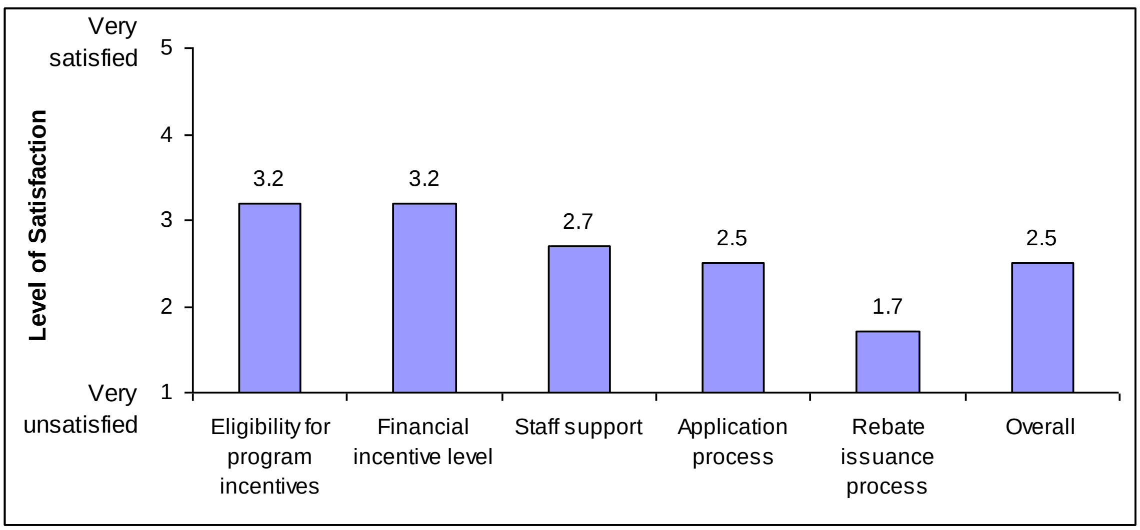
The end-use customer survey revealed that the majority of respondents are "very satisfied" or "satisfied" with the program application process (Table 3-23). However, developers' satisfaction with the application process was a 2.5 on a scale of 1-5 with "5" being "very satisfied," suggesting less than optimal satisfaction (Figure 3-7). Both program participants and developers were least satisfied the process for issuing rebates. Eleven percent of program participants were either "unsatisfied" or "very unsatisfied" with the timeliness and accuracy of the rebate process, and the average score given by developers when asked to rank the rebate issuance process was a 1.7 on a five point scale with five being the highest score.

Table 3-23. Program Participants' Satisfaction with the CORE Program

CORE Program Elements	Very Satisfied	Satisfied	Unsure	Unsatisfied	Very Unsatisfied
Program application process	51%	26%	20%	3%	-
System requirements for eligibility	50%	30%	19%	1%	-
Program staff support	39%	39%	16%	7%	-
Project financial incentive level	46%	43%	9%	3%	-
Timeliness and accuracy of rebate process	50%	24%	14%	7%	4%

Source: CORE Program End-Use Customer Survey

Figure 3-7. Developer's Satisfaction with CORE Program

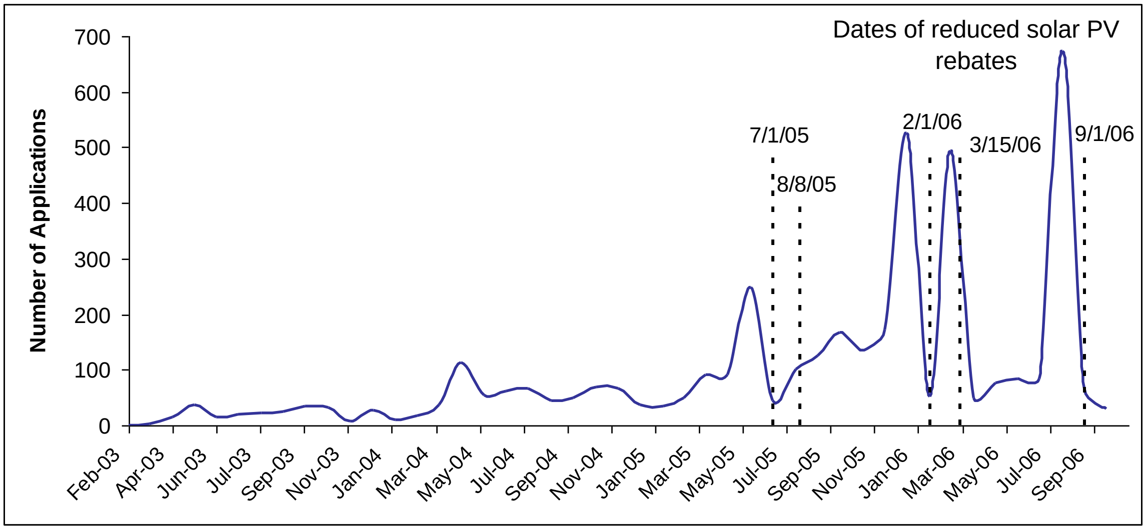


Source: CORE developer interviews

<u>CORE Program Applications</u>

The number of applications to the CORE program between 2003 and 2006 is shown in Figure 3-8. The time period represented in the figure begins in February 2003, the date of the first solar PV project in the current CORE database, and ends in October 2006, the date of the most recent PV project in the database used for this assessment. During this timeframe, 4,268 solar PV applications were processed.[91] This figure shows the surge in program applications before the dates of the reduced solar PV rebates. Therefore, a key feature that seems to attract the developer's attention is a reduction in the rebate. These data indicate that changes in rebate levels result in large, rapid fluctuations in program activity. These fluctuations make it difficult for market participants (developers, manufacturers, etc.) to conduct effective business planning, and to respond to the needs of the market in an efficient manner. Efforts should be made to provide sufficient notice of changes in rebate levels, and to maintain a more consistent level of program activity over time. While unexpected changes in market conditions may require sudden changes in the program under rare circumstances, the Board should strive to establish and implement a long-term plan, and to implement gradual, predictable changes in program policies and procedures. A long-term plan and clear communication of program policies and procedures should improve market stability.

Figure 3-8. Number of Solar Applications over Time Shown (through September 1, 2006) with the Dates of Reduced Solar PV Rebates.



Source: CORE program database

In comparison, the number of applications over time for non-solar technologies is much smaller and thus is shown in tabular format below (Table 3-24). The time period represented in the table begins with November 2001, the date of the first non-solar project in the current CORE database, and ends in August 2006, the completion date of the most recent project in the database used for this assessment.

[91] The total number of program applications during the period of assessment is actually 4,269 . However, one solar PV project does not have an application date listed in the CORE program database, and thus it is not included in the counts of processed applications represented in figures presented in this section.

Table 3-24. Number of Non-Solar Applications Over Time (through September 1, 2006)

	Number of Applications		
Date	Biomass	Fuel Cell	Wind
Nov-01		1	
Mar-02		1	
Dec-02			1
Apr-03			1
May-03			1
Jun-03			1
Sep-03	1		
Oct-04			1
Jan-05	1		
Mar-05	1		
Apr-05	2		1
May-05		3	
Jun-05	1		
Feb-06	1		
Apr-06			1
May-06	1		
Jul-06	1		1
Aug-06	1		1
Total	10	5	9

Source: CORE program database

The total number of applications for non-solar technology installations is 0.6% of the number of solar PV applications. Biomass, wind and fuel cell technologies all have higher capacity factors than PV, and thus produce more energy than a similarly sized solar PV system. In addition, biomass and wind systems are generally more cost-effective than PV. Therefore, more marketing of non-solar technologies is warranted.

CORE Rebate Levels

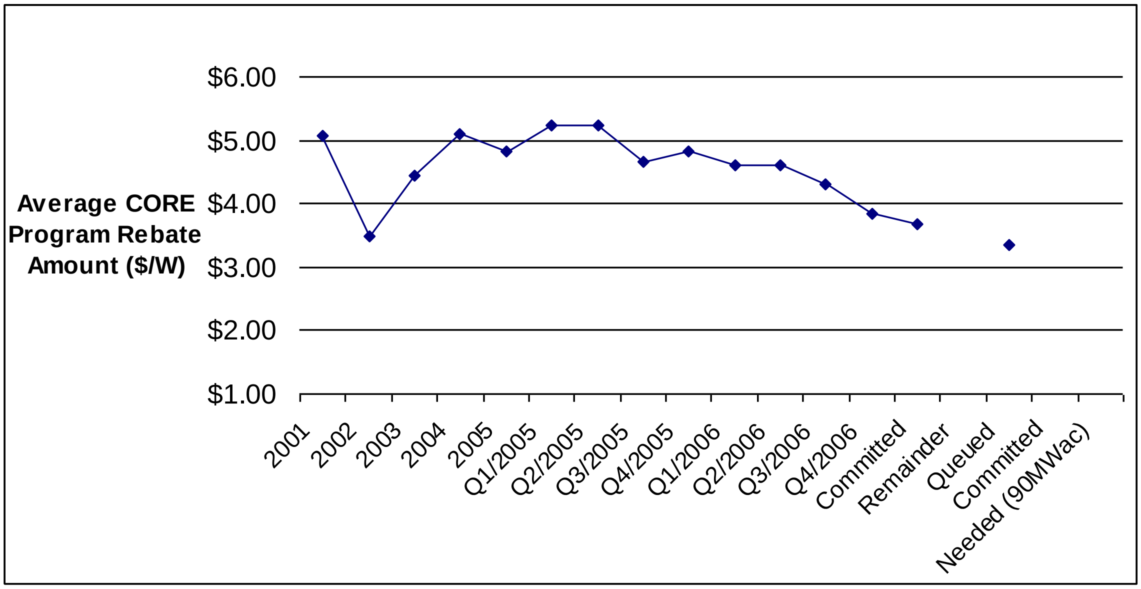
Since 2005, the Office of Clean Energy has reduced solar PV rebates five times for the private sector and three times for the public sector (Table 3-25). The average solar PV rebate amount from 2001 through 2006 is shown in Table 3-25.

Table 3-25. Solar PV Rebates Over Time (through September 1, 2006)

		PRIVATE SECTOR					
	Date effective	Through 6/24/05	7/1/05	8/8/05	2/1/06	3/15/06	9/1/06
System Size	0 to 10,000 watts	Lesser of $5.50/W or 70% of installed costs	$5.30/W	$5.10/W	$4.95/W	$4.35/W	$3.80/W
	10,001 to 40,000 watts	Less of $4.00/W or 60% of installed costs	$4.35/W	$3.90/W	$3.70/W	$3.20/W	$2.75/W
	40,001 to 100,000 watts	Lesser of $4.00/W or 60% of installed costs	$3.75/W	$3.45/W	$3.20/W	$3.00/W	$2.50/W
	100,001 to 500,000 watts	Lesser of $3.75/W or 60% of installed costs	$3.60/W	$3.20/W	$3.05/W	$2.80/W	$2.25/W
	500,001 to 700,000 watts	N/A					$2.00/W
		PUBLIC SECTOR					
	Date effective	Through 6/24/05	7/1/05	8/8/05	2/1/06	3/15/06	9/1/06
System Size	0 to 10,000 watts	Lesser of $5.50/W or 70% of installed costs	$5.30/W	N/A	N/A	$5.15/W	$4.40/W
	10,001 to 40,000 watts	Less of $4.00/W or 60% of installed costs	$4.35/W	N/A	N/A	$4.15/W	$3.45/W
	40,001 to 100,000 watts	Lesser of $4.00/W or 60% of installed costs	$3.75/W	N/A	N/A	$3.50/W	$2.80/W
	100,001 to 500,000 watts	Lesser of $3.75/W or 60% of installed costs	$3.60/W	N/A	N/A	$3.40/W	$2.60/W
	500,001 to 700,000 watts			N/A	N/A		$2.05/W

Source: NJ CORE program Update. http://www.njcep.com/media/COREprogramUpdate081706.pdf.
Note: Also effective on February 1, 2006: $0.25/W extra if PV modules manufactured in the state of NJ; $0.25/W extra for residential solar applications less than 10 kW for participation in the New Jersey Home Performance with Energy Star program

Figure 3-9. CORE Solar PV Rebate Level over Time (through September 1, 2006)



Source: BPU Class I Renewables Experience through 120506

Feedback from developers and program participants indicate that the instability of the rebate levels and the lack of transparency about the levels are major issues facing the CORE program.

Developers not currently participating in the CORE program felt that the incentive levels should be more stable and better communicated. Developers who have participated in the program rated it on a scale of 1-5 with "5" being very satisfied. The participating developers rated the rebate issuance process at a 1.7, showing that they were unsatisfied with this process. The developers gave the financial incentive level an average score of 3.2, showing that they feel neither strong satisfaction nor dissatisfaction with the rebate levels.

CORE customers also emphasized the importance of stable rebates. Forty-six percent of customers in the CORE program stated that the most important reason they participated in the program was to obtain a rebate.[92] Ninety-four percent of the CORE customers surveyed felt that the CORE program rebate made it possible for the system to meet the cost/payback needs. Of the respondents, only 26% said they would still have installed the system if the CORE program rebate was 25% less than they received. Also, 89% of customers were "very satisfied" or "satisfied" with the project financial incentive level.

Program Impacts on System Costs and Trade Infrastructure

CORE developers who were interviewed were asked to estimate the impact of the New Jersey Clean Energy programs on upfront, installed costs for renewable energy projects. Many respondents pointed out that the rebate amount, which has decreased over time and varies for residential, commercial and

[92] From the CORE program End-Use Customer Survey. Twenty-four percent participated to lower electric bills and 19% participated to reduce the impact on the environment.

public projects, does not lower installed costs because those costs all must be borne long before the rebate is issued. A few respondents claimed that the current value of the rebate is zero, citing that new program activity has been frozen for almost a year. Moreover, receiving the rebate monies has often taken over six months, during which time either the customer or the project developer had to bear interest costs on the project, thus lowering the present value of the rebate.[93] On average, respondents estimate that the Clean Energy programs bring down costs for residential projects by $3,740/kW, and commercial projects by roughly $2,300/kW.

When asked about the cost of solar PV in terms of levelized costs over time (cents/kWh), developers considered the net present value of the New Jersey rebates, long-term SREC values, federal tax incentives, financing mechanisms and the full life-time (30-40 years)[94] for average projects. Without the benefits conferred by the New Jersey Clean Energy programs, the estimated cost for solar PV is 38.1 cents/kWh. When the program benefits are included, the estimated cost drops to 12.5 cents/kWh. Again, this average represents a broad range of estimates based on particular assumptions for an average project.

The program's impacts are seen to be similarly large when framed in terms of payback (of initial investment) in number of years. Notwithstanding, developers have different concepts of an average project, and the assumptions vary in important ways between commercial, residential and public projects. The impacts of the CORE program are estimated to bring payback periods down by over 60 percent, from 22.6 years (without the program incentive) to an average of 9.2 years (with the program incentive). In general, commercial projects are estimated to have payback periods 25-35% shorter than residential projects. This is due to the ability of commercial entities to take advantage of more substantial tax incentives than are available to residential consumers, as well as economies of scale associated with larger projects.

A few developers estimated the CORE program's impact on an average project in terms of percent return-on-investment (ROI). These respondents were mostly active in the commercial sector, where customers tend to demand a higher ROI than do residential customers. Without the CORE program's economic benefits, the average project is estimated to have an 8 percent return on investment, whereas the CORE program's impacts bring it up to a 12 percent ROI.

Developers had mixed opinions about the influence the CORE program has had on the market and trade infrastructure for solar PV in New Jersey. They were asked whether the CORE program has influenced the trade infrastructure in "positive" and/or "detrimental" ways (in a 1-5 scale system). Respondents expressed that, on the whole, the program's influence on market infrastructure has been positive. However, many respondents noted that the effects of the program have changed since the program funding became oversubscribed. They claim that the recent slow down in program activity, changes in rebate levels and lack of a clear long-term plan for the future of the program has been detrimental to industry development. Several developers noted that development of industry infrastructure would have benefited from fewer changes in rebate levels and more long-term planning, even if this meant starting with and maintaining lower rebate levels over time. Others

[93] One large commercial project's interest payments exceeded $30,000 while waiting for the rebate after the project was installed.

[94] This life-time was noted from the developer interviews. Most standard levelized cost models do not go beyond 20-30 years.

indicated that program staff had not initially communicated sufficiently with the industry about the level of available funding and that this had caused significant business losses for developers.

Program staff report that while the pace of rebate payments for some sectors have slowed down at points to keep pace with their budget category, at no point did approved rebates go unpaid and at no point has there been an widespread slow down in rebate payments. Staff has been constrained by the need to avoid spending beyond the limits of the budget and has made strong efforts to maintain timely payment of incentives despite the overwhelming demand for program incentives.

Preferred Incentive Mechanisms

Participating developers were much divided in their responses regarding which options for incentive mechanisms they most prefer. They provided numerous verbatim comments about the strengths and weaknesses of different approaches to designing an incentive mechanism as they relate to different customer classes (commercial, residential and public). Generally, upfront rebates are perceived to be the simplest, most understandable and secure mechanism for the residential sector (under 10 kW). It was commonly asserted that, without an upfront rebate, there would be few sales of solar PV to the residential sector.

A number of participating and non-participating developers suggested transitioning to a feed-in tariff approach such as that used in Germany noting that the system is simpler and would leverage a greater level of project investment. In addition, some developers focused on the importance of basing program incentives on system performance, noting that in a rush to remain competitive and secure funding commitments, some developers are compromising on quality. A number of developers mentioned that they prefer the performance based incentive approach used in California.

Participating end-use consumers clearly prefer a fixed upfront rebate, as evidenced by responses to the CORE participant survey. The majority (about 86%) of customers in the CORE program preferred a fixed, up-front rebate to a contract with an electricity supplier or a rebate spread out over time.

Incentive Caps

Regarding whether more solar PV projects would be developed in New Jersey if the program incentive caps were changed or removed, the developers were evenly split. About 40% said they believe more projects and additional solar capacity (kW) would be brought to market if incentive caps were removed, and 40% said it would not change the volume of sales. Roughly 20% were uncertain. A number of respondents believe that if the residential caps were removed, there would actually be *fewer* projects of *larger* size sold to the residential segment.

Twenty percent of program participants surveyed said that the incentive cap did have an effect on the size of the system installed. All respondents felt the cap had no other major impacts.

Barriers to Program Participation

Feedback on barriers to participation in the CORE program was collected from participating developers, non-participating developers and participating end-users.

CORE program developers listed what they believe are the biggest barriers for customers in the program (Table 3-38). Twenty-four percent cited long-term uncertainty regarding SREC market values and durability of the RPS requirement, and 13% cited high first-costs. Almost half of the respondents cited the program’s own instability, lack of monies, and general uncertainty about rebate availability as the most important program barriers. These barriers are seen to be interrelated. For example, availability of rebate monies mitigates high first costs and limited access to financing. Developers explained that the BPU has changed the rebate levels multiple times without sufficient notice which has resulted in major disruptions to the sales cycle.

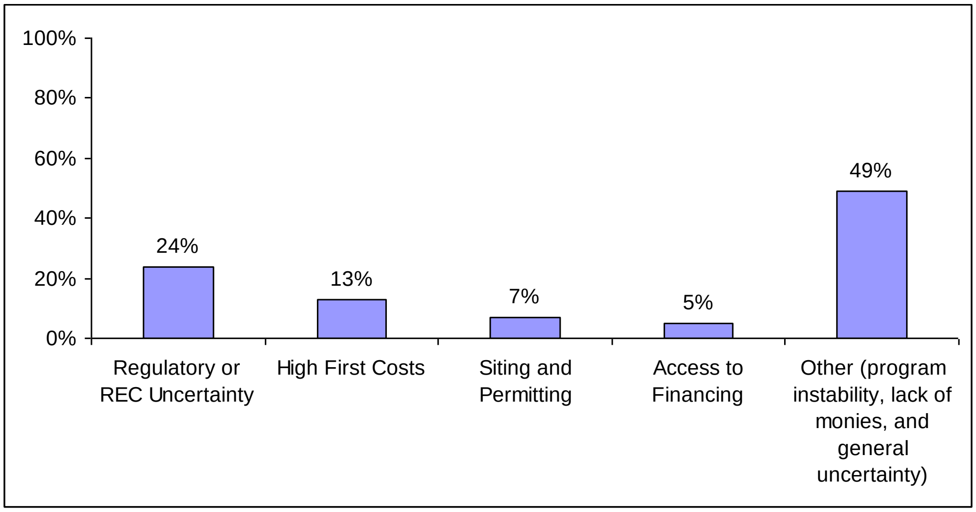
It is difficult to determine what length of time could be considered "sufficient" notice of a change in rebate levels. Program staff note that at least 30 days notice was provided in most cases. It is possible that a greater amount of notification time or a more well-defined, transparent long-term plan regarding the schedule of rebate levels would have minimized the large fluctuations in program activity which occurred prior to drops in rebate levels (Figure 3-8). Although different program planning strategies might have been preferable in hindsight, the fact remains that the program needed to make changes fairly quickly in order to avoid over-spending its budget, and fairly few options were available other than reducing incentive levels.

While surges in sales prior to changes in rebate levels do provide a short-term boost in business for developers, many market participants expressed the logical perspective that a more consistent and predictable level of activity in the market would facilitate more effective business planning, as well as a greater ability for the industry to prepare for and efficiently serve the needs of the market.

A non-participating developer cited New York as the only east-coast state that has maintained a stable incentive program over a long period, and stated that most states other than California have had programs with too much instability. This reflects the enormous challenge associated with maintaining stable incentive programs given the immature state of solar markets which exist when programs are initiated. It also puts the CORE program's issues in some context, demonstrating that New Jersey is not alone in its efforts to balance priorities and identify appropriate incentive levels. New Jersey's challenges are unique in that the state has much more aggressive solar development goals than other states that are grappling with incentive program design and implementation issues. Therefore, any hurdles encountered in New Jersey will be magnified substantially relative to those in other states.

Non-participating developers noted that while the SREC system in New Jersey is robust, the uncertainty around SREC values is too great and the program is too complicated. Some developers cited Delaware's REC system as simpler and more favorable; project owners sell RECs to the state, which in turn sells the RECs to suppliers for use in RPS compliance.

Figure 3-10. Participating Developers' Top Barriers to Participating in the Program



Source: CORE developer interviews

Developers suggested some programmatic actions to reduce barriers including ensuring certainty in the availability of the rebate, ensuring longevity and reducing the number of extensions given outside of program rules.

CORE customer survey, respondents listed what they felt were the major barriers to participation in the program (Table 3-26). The major barrier for participants was the first costs, with the structural limitations of the building and specific program requirements following. Also, one percent of respondents felt the CORE program was very effective in reducing barriers, while 27% of participants surveyed felt the CORE program was somewhat effective in reducing barriers.

Table 3-26. Customer's Top Barriers to Participating in the Program

Major Barriers to Participation	
First Costs	54%
Other: Structural Limitations of Building	30%
Specific program Requirements	19%
Lack of Education and Awareness	16%
Other: Miscellaneous Issues	12%
Lack of Available Financing	6%
None	4%
Aesthetics	4%
Other: Permit Availability	4%
Uncertain of Available Contractors	3%
Not Remaining in the Home/Building Long Enough for Project Payback	3%

Source: CORE program End-Use customer survey. Multiple responses were allowed.

With the first costs being the most cited major barrier, it is important that the rebate structure is clear and the program can ensure certainty of the rebates. Related to the upfront cost barrier, some developers noted the timing of rebate payment as a major program deficiency, explaining that it can be difficult for project owners and/or developers to bridge the gap between the point at which they must pay for equipment and installation, and the point at which they receive rebate payment. One developer reported,

> *"Waiting so long for the rebate (up to three months after the system is completed) is painful for us because we pay for equipment one to two months before installation begins. It can be a six month gap."*

Some project owners or developers must take out loans for the period between project completion and rebate payment and interest payments are non-trivial. One developer reported having paid $25,000 to $30,000 in interest on a loan for a 240 kW system while it awaited rebate payment.

A few developers explained that financing is available, but that conditions are not generally as favorable as they should be since lenders fail to view the solar equipment as an asset. Developers noted that homeowners without much equity in their homes can have difficulty securing project financing. One developer highlighted the value of no-interest loans available from Home Depot.

Both participating and non-participating developers recommended that the BPU offer its own financing program that would recognize solar as an asset and assist project owners and developers with the cash flow challenges associated with getting a system up and running.

Barriers to Non-Solar Projects

As previously mentioned, non-solar projects comprise only 0.6 percent of all applications to the CORE program. Also, the program did not meet the BPU's goal to install 6 MW of non-solar distributed generation in 2005; 1.9 MW of biomass and wind systems were completed (paid) during 2005.[95] However, average first costs for biomass and fuel cell projects are substantially lower than those for solar PV projects, suggesting that first costs for these non-solar projects should be less of a barrier than for solar projects. The buzz about solar PV in New Jersey and across the nation may also be a barrier to the installation of non-solar technologies. Arguably, solar PV is receiving more media attention and is becoming better known than biomass and fuel cell projects. Large wind projects also receive substantial media coverage and are becoming more familiar to the public. However, only on-site wind projects are funded through the CORE program and these smaller scale projects face greater barriers than PV in the areas of siting, permitting and maturity of installer infrastructure.

When commenting on what barriers exist for the installation of large-scale renewable energy projects in New Jersey, many participating developers suggested that future uncertainty with the CORE program itself is the largest barrier. In particular, they pointed to uncertainty regarding long-term REC values, uncertainty regarding the availability of and future of rebates, long bureaucratic processes and inability to contact the BPU to get questions answered or rules clarified. A few

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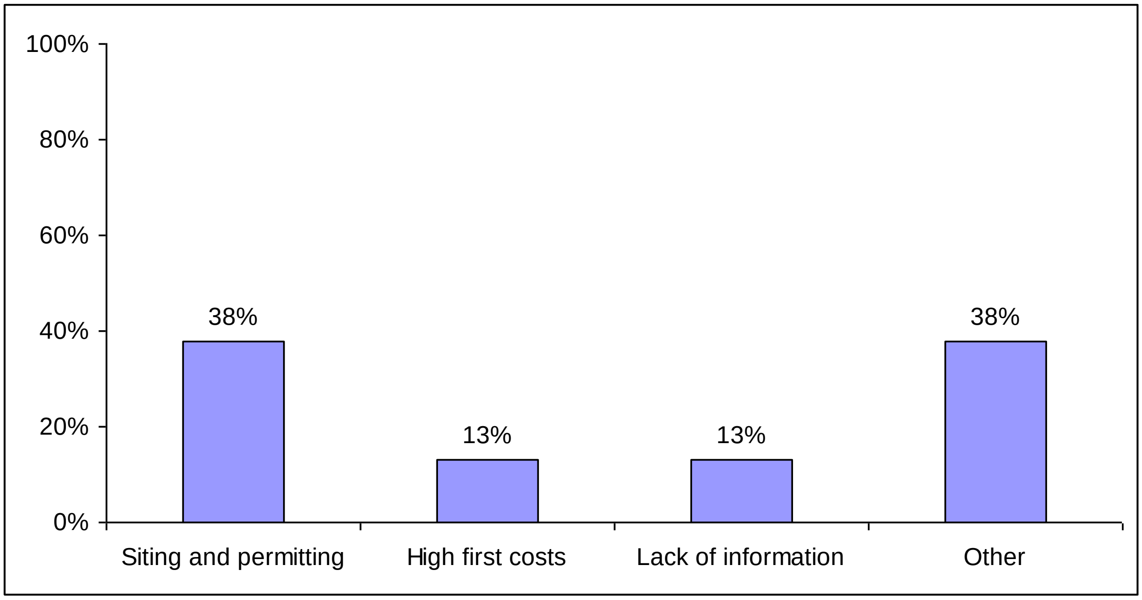
[95] CORE program database. Since this assessment counts capacity additions in the year they were paid, the Jersey Atlantic Wind project is not counted here. Although the 7.5 MW Jersey Atlantic Wind project was installed in 2005 it did not receive a payment from the CORE program until 2007. It did receive a payment from the Renewable Energy Project Grants and Financing program in late 2006.

respondents also mentioned siting and permitting restraints and uncertainty regarding the future of federal tax incentives.

Non-participating developers also highlighted siting and permitting barriers, noting that there is significant NIMBYism, and bureaucracy in the New Jersey, and that the permitting cycle is very long (Figure 3-11). One developer noted that there is little reason to develop a wind project in New Jersey when there is so much less NIMBYism and bureaucracy in Pennsylvania, making wind development much easier in that state.

Figure 3-11. Non-Participant Developers' Top Barriers to Large-Scale Projects



Source : CORE non-participant developer survey

The format of the CORE program budget categories may also be a barrier to non-solar projects. The budget categories are

- Less than or equal to 10kW Private;
- Greater than 10kW Private;
- Public- Non Schools;
- Public Schools K-12; and
- SUNLIT.[96]

The categories do not differentiate between solar and non-solar projects. If there were budget limits for each technology category, the program would send a stronger signal to encourage participation in all technology categories, and would better reflect New Jersey's solar and non-solar development

[96] The SUNLIT program is offered through the New Jersey Housing and Mortgage Finance Agency.

goals. For example, the Self Generation Incentive program in California has budget caps in the different funding groups.

Barriers to small wind projects in New Jersey were assessed based on both interviews with wind energy equipment manufacturers and responses to a survey conducted by the New Jersey Wind Working Group (NJWWG) include:[97]

- Land resource issues in New Jersey make small wind less feasible, because small wind is difficult to site and permit in urban areas.
- There is no specific requirement in the Renewable Portfolio Standard for utilities to purchase RECs from New Jersey based wind projects, as there is for solar.
- No convenient REC system like solar RECs.[98]
- Lack of accurate wind data available and, where available, the resource is not sufficient to make projects economical.
- Lack of technology for low wind regimes.

Possible barriers to biomass projects include the lack of sustainable biomass resources, and possible barriers to fuel cell projects include technological and cost barriers. The technological barrier is mainly due to the fact that only renewable-fueled fuel cells are currently eligible for funding through the CORE program. Also, the economics of fuel cell projects are typically unfavorable.[99]

A more complete discussion of barriers to renewable energy project development in New Jersey is included in the market-level assessment in Volume 2, Section 2.

3.2.5 Program Management Assessment

This section discusses CORE program management over the lifetime of the program, focusing on the developers' and customers' views of the program management.

Program Management

Since its inception, the CORE program has been under the management of three different entities: the Electric Distribution Companies, the New Jersey Board of Public Utilities' Office of Clean Energy, and Honeywell, playing the role of market manager with Conservation Services Group and the Vermont Energy Investment Corporation functioning as the direct administrators of the program (Table 3-27). However, the vast majority of projects installed through the program during the assessment period (2001-2006) were installed under the management of the BPU.

[97] NJWWG Stakeholder Survey was conducted by MarketSight® Analysis.

[98] This was listed as a barrier by many, though any behind the meter system (solar or non-solar) can participate in the SREC program.

[99] E Source. Emerging Fuel Cell Technology. August 2002. ET-1. and the National Fuel Cell Research Center. Accessed at http://www.nfcrc.uci.edu/fcresources/FCexplained/challenges.htm.

Table 3-27. CORE Program Management

Time	CORE program Manager
2001 through mid-2003	Electric Distribution Companies (EDCs).
Mid-2003 through 2006	NJ BPU, Office of Clean Energy
2007 to current	Honeywell with the Conservation Services Group and the Vermont Energy Investment Corporation

Developers' and Customers' View of the Program Management

Participating developers rated various elements of the CORE program, on a 1-5 scale, with *5* denoting "very satisfied" and *1* denoting "very unsatisfied" (Table 3-22). Their overall level of satisfaction with the program the time data was collected for this assessment in the spring of 2007 was 2.5, suggesting less than optimal satisfaction. The rating for staff support was a 2.7, also suggesting less than optimal satisfaction.

Many developers suggested that their level of satisfaction with the program management was once very high but that it had significantly dropped in the past two years. This was true for each of the individual elements that were rated in the survey.[100] Participating developers voiced a number of complaints, described below. It is important to note that much of the developers' frustration is related to the slow down in sales related to the oversubscription of the program's PV rebate funding. While this has slowed the pace of rebate application approval, it reflects budget constraints that are beyond the control of staff administering the program, and should not be interpreted as poor administrative performance on the part of BPU staff. However, the occurrence of such a large-scale program oversubscription could potentially have been avoided through more careful long-term program planning.

The views of participating developers regarding areas of deficiency in program management are summarized here.

1. The lengthy time required to get a project application approved. Based on the CORE program database, the time to get a project application approved was less than 20 days for all years but 2006. For 2006, the number of days to process an application from pre-installation to approval letter was 131 days[101] (Table 3-28). The BPU's goal is to approve projects in 30 days. This slow down in processing time is due to the fact that demand for program participation far outweighed available funds. Therefore, it does not reflect poor administration of the program on a day to day basis, though program oversubscription may have been averted or minimized through more careful long-term program planning.

[100] It was common to hear respondents claim that various program elements functioned excellently in the past and they would have rated them a "5" a couple years ago.

[101] This long application approval time in 2006 is likely due to the lack of funding and project queue.

Table 3-28. Project Application Approval Time

Approval Year	Days
2002	1
2003	14
2004	17
2005	11
2006	131
Average of All Years	35

Source: CORE program database

2. The lengthy time required to receive rebate monies after approval has been given. Based on the CORE program database, the average time to issue rebate monies was 63 days for all years (Table 3-29). The BPU's goal is to issue rebate checks within 30 days of the inspection. Therefore, owners of the systems have to carry the up-front cost of the project for a longer time than anticipated before receiving the rebate monies, thus reducing the true value of the rebates.

Table 3-29. Project Rebate Time

Completion Year	Days
2003	57
2004	49
2005	66
2006	81
Average of All Years	63

Source: CORE program database

3. False leads occupying queue, and inconsistent treatment of applicants. Developers explained that in a rush to secure funding commitments, other developers had submitted applications for projects that were not fully committed to the solar investment and that the BPU should require payment of a deposit to reserve a spot in the queue. Some developers also explained that the BPU has been inconsistent in its enforcement of some program rules such as granting extensions to projects that were not built in the specified timeframe. The issues identified in these complaints have not been independently verified as accurate, but are presented here because they reflect the views of the majority of 30 participating developers interviewed as part of this assessment.

Marketing Assessment

This section provides an overview of the marketing materials available for review as well as the developers' and customers' views of marketing and outreach for the CORE program.

Overview of Marketing Materials

Program Web site

The program Web site provides a program overview, news and contact information. The program application forms and interconnection forms are easily accessible on the site. Case studies showing success stories are included, which provides potential applicants to the program tangible examples of successful projects. The Web site also contains a list of vendors for solar PV, fuel cells, biomass and wind. Press and media documents and events are located on the general New Jersey Clean Energy program Web site. However, portions of the Web site were not up-to-date at the time of this assessment,[102] and it could be streamlined to make it easier to navigate. For example, at the time of this assessment the program's policies and procedures were included within a "program update" document that is not highlighted as part of the main program summary.

Marketing materials on the Web site focus on solar PV. There is a "Plug into the Sun" link with a guide to buying a solar electric system. This page includes material on a variety of topics of use to potential solar buyers. Another tool to aid solar projects applying for the CORE program is the New Jersey Clean Power Estimator. The Estimator shows data on the net cost, daily output, PV production, monthly output, monthly savings and costs, cash flow, shading analysis, cumulative discount cash flow and electric bill comparison, with a few inputs about the size, tilt and direction of the system and the electric bill, loan life and loan rate. The additional information on solar systems is thorough and helpful, but the website is lacking additional information about the other eligible technologies: fuel cells, biomass technologies and wind turbines.

The Web site pages about the CORE program also contain a link to the New Jersey Energy Efficiency programs website. Therefore, some cross-marketing is occurring through the program website. The Web site has links to other related information including industry association links (i.e., Solar Energy Industries Association, AWEA, and the U.S. Fuel Cell Council) and general renewable and clean energy information links (i.e. Florida Solar Energy Center and the NJ Wind Resources Map).

Other Materials

The CORE brochure describes the rebate program and states up-front the rebates provided by the program. Wind turbines, biomass technologies, and solar PV are listed on the brochure as technologies that can receive the rebates.

Marketing management, customer and developer training information, and direct marketing and outreach information was not available for review.

Developers' and Customers' Views of the Marketing and Outreach

Participating developers generally believe that the CORE program's marketing and outreach informational efforts will have a short-term effect on public awareness and knowledge of renewable energy options. Over 63% of the respondents believe the influence will be short-term, while 19% believe they will be long-term. Another 19% were not sure.

[102] The website has been updated in 2007; however, Chart I and II showing New Jersey Clean Energy program Incentives have "2006" as a header.

Participating developers give the CORE program a high score in terms of how much the program has influenced public awareness (2.7 out of a 3-point scale). Without the rebate program, many respondents commented that there would be virtually no market in New Jersey for solar PV.

A number of developers commented that they feel the CORE program does very little marketing and that most activities bringing the program into customer awareness have been performed by the installation and developer community. Moreover, the majority of developers interviewed commented that both the long- and short-term influences on public awareness from CORE program's marketing have not been positive in the past few years.

Of the ten non-participant developers surveyed, all ten were familiar with the CORE program. However, only one in ten believed that New Jersey consumers have the information needed to make informed decisions on investments in renewable energy technologies.

The majority of the verbatim comments about CORE's outreach efforts from developers in the CORE program centered around the uncertainty of the availability of rebates in the program. For example, one developer commented,

> *"The impact of the outreach currently is largely negative… the outreach is strong, but the program is being seen by customers as weak, because the monies run out, the queue is long, and there is a lack of CORE program explaining what is going on."*

Outreach surrounding the current status of the CORE program would likely increase the CORE program participants' certainty and view of the program. For example, it would be helpful to communicate the state's long-term commitment to building renewable energy capacity, as evidenced by the RPS requirements which steadily increase through 2020.

3.2.6 Recommendations

1) Based on a September 12, 2007 Board Order, the research team understands that a solar rebate program will be continued through the next Societal Benefit Charge (SBC) funding cycle for small projects, but that larger PV systems would be ineligible for rebates. Based on an analysis of PV project economics by size and market sector, the research team recommends continuation of rebates for privately-owned systems up to 40 kW, and for publicly-owned systems up to 100 kW It is recommended that a rebate incentive structure continue for small solar and for non-solar technologies up to 1 MW that serve on-site load. While many developers expressed support for a feed-in tariff or performance-based incentive approach, and this is an approach worth considering further, a rebate approach seems reasonable given the path the Board has begun to lay out with its recent Board Order introducing a multi-year SACP schedule. In addition, rebates are easy to administer, and will reduce upfront system costs for program participants. Program participants (86%) also indicated that a rebate is the preferred form of financial incentive.

2) The program should incorporate several **performance-related components**:

    - Step up efforts related to on-going **monitoring of system performance**

    - Revise minimum technical requirements for system installation to clearly specify a range acceptable for module orientation for PV systems, and appropriate minimum system design requirements for non-solar projects.

- Require all systems to be metered and require use of metered data as the basis for SREC creation (this could be phased in over a two year period).

- In the web site listing of CORE program installers indicate which installers have received **North American Board of Certified Energy Practitioners (NABCEP) certification**. This should encourage more installers to obtain certification, thus improving confidence in the quality of installations. Also, the BPU should consider sponsoring NABCEP training courses to make it easier for installers to gain the skills needed to perform high-quality installations.[103]

3) An **annual budget** of $10.6 million is recommended for the upcoming SBC funding cycle (2009-2012). Recommended incentive levels are presented in Volume 1, Section 5.

   The **incentive levels** and recommended program budget are based on analysis which considered New Jersey's renewable energy development needs, by technology, in order to stay on track to achieve RPS requirements through the next SBC funding cycle. The analysis also factored in project costs and barriers, and an IRR target of 12% was used. Discussion of the basis for these recommended incentive levels is provided in the portfolio level assessment, Volume 1, Section 5.

4) In addition to baseline rebate levels, projects **incentive adders** of $0.25/W should be made available if the applicant: a) is an ENERGY STAR rated home, a LEED certified building, or a residence or commercial project demonstrating that significant energy efficiency measures have been completed at the site; b) major system components used in a project were manufactured in New Jersey. Adders could be offered for projects with other positive project features as well, such as being located in a congested area of the distribution system, or in an area targeted for smart growth initiatives.

5) All participating buildings should be **required to complete an energy audit** before the applicant receives a rebate. Applicants would not be required to implement recommended measures, but if they do, they may be eligible for an incentive adder. The goal is to ensure that all program participants are aware of the cost effective benefits of energy efficiency, and to facilitate cross-marketing of the BPU's energy efficiency and renewable energy programs.

6) Consider offering a **low interest financing** option to Class I renewable projects serving on-site load, subject to further analysis regarding appropriate target markets. For solar, this may include projects larger than the 40 kW rebate-eligibility limit. Feedback from market participants indicated that uncertainty associated with SREC / REC values will make project finance more expensive, that it can be difficult for program participants to bridge the gap in timing between paying for a system and receiving a rebate payment. In addition, the majority of past program participants have been wealthy individuals and it would be beneficial to make the program accessible to a broader population of potential participants. While other strategies (i.e., long-term contracting requirements) should be explored as well, a financing

[103] Installer training has been a strong focus for the New York State Energy Research and Development Authority (NYSERDA) in its efforts to establish a successful solar market and to ensure that incentive funds are spent on high-quality system installations.

program is something concrete that the BPU can offer near-term. NYSERDA's Energy $mart loan program can serve as a model for developing a financing program in partnership with banks serving New Jersey's communities. The Board's decision to offer such a financing program should take into consideration the tax environment that exists in 2009. If the solar investment tax credit (ITC) is extended beyond 2008, a state financing program could actually have a negative effect on project economics.[104]

7) **Encourage development of more non-solar projects in the CORE program**. This could be accomplished by:

   - providing additional Web site educational information and resources focusing on non-solar technologies;
   - performing more targeted marketing to entities most likely to be able to install non-solar technologies (i.e. larger commercial or institutional entities);
   - splitting the budgets into solar and non-solar categories to more clearly reflect the BPU's goal to develop both solar and non-solar technologies;
   - educating local officials about small wind and biomass technology applications and/or developing model ordinances to minimize siting and permitting barriers;
   - establishing a biomass working group and continuing the efforts of the wind working group to bring industry players together to address barriers specific to these energy resources;
   - communicating with representatives from other northeastern states that are taking similar steps to reduce barriers to wind and solar project development;[105]
   - prioritizing the completion of a few highly visible pilot projects that can be used as models for success.

8) Establish a **Policies and Procedures Guidebook** for the CORE program with clear, concise, comprehensive and easy-to-navigate information about the program. Make the handbook available on the Web site and update the handbook when changes occur.

9) Take steps to **establish program certainty and longevity**, and to emphasize the state's long-term commitment to developing market for on-site renewable energy systems.

[104] As set forth in the Energy Policy Act of 2005, the value of the solar ITC will be reduced or eliminated if project owners take advantage of "subsidized energy financing." See Wiser and Bolinger (2006) "Federal Tax Incentives for PV: Potential Implications for Program Design."

[105] Massachusetts has been very active in addressing barriers to both biomass and small wind resources. The state Division of Energy Resources facilitates a biomass energy working group, and is addressing many barriers to small wind by working directly with communities through its "Community Wind" program.

10) **Increase program transparency**. Clearly communicate any changes in rebate levels or program eligibility requirements well in advance of the point when changes are scheduled to take effect, describe conditions under which changes would take place, and make an effort to minimize any changes. Also, streamline program Web site to make it easier to navigate, using less text and more bulleted points where appropriate.

11) **Set realistic goals for program processes** (i.e. approving applications and sending rebate checks) and meet them to build confidence among market participants.

12) Recognizing that high upfront costs have been a barrier for program participants to date, work to educate the public and the investment community about the **value and long-term nature of revenues from the SREC market**. Through clear, consistent messaging and maintenance of appropriate SACP levels, the BPU can facilitate a shift away from a dependence on a rebate incentive structure.

13) **Improve program data management practices.** Efforts should be made to improve upon the consistency and quality of data entry, and the BPU should compile one database with program records from all program years. The database provided to the research team lacked data for projects installed during the 2001 through mid-2003 timeframe.

3.3 Renewable Energy Project Grants and Financing Assessment

3.3.1 Program Performance

The Renewable Energy Project Grants and Financing program has evolved since the program's inception in 2001. Originally the program was called the Grid Supply program (GSP), and it provided financial incentives in the form of upfront grants and production incentives. The program was modified in 2004 to provide upfront grants with low-interest financing and was renamed the Renewable Energy Advanced Power Plant program (REAP). In 2005, the program was renamed the Renewable Energy Project Grants and Financing program to better reflect the nature of the program. Legacy projects from the Grid Supply and REAP phases of the program are still receiving payments under the current Renewable Energy Project Grants and Financing program (REPGFP). In fact, these payments to legacy projects are currently the only funding expenditures being made under the program, which is not accepting new applications.

Grid Supply Program

In 2001, the BPU Grid Supply program was introduced to provide incentives to large-scale grid connected renewable energy projects in New Jersey through a competitive bid process. The program was designed to promote competition among technologies, encourage cost effective renewable grid supply technologies and facilitate the development of a thriving, diversified renewable energy market. Incentives were offered both in the form of upfront grants and five-year production incentives.

Of the five proposals that were accepted under this phase of the program, only one has become operational, and one is still in the development process. The remaining projects approved under this phase of the program were terminated for lack of progress at the applicants' request.

The Community Energy 7.5 MW Jersey Atlantic Wind (JAW) Project, located on the site of the Atlantic County Utility Authority's sewerage treatment plant, was completed in December 2005. The project was expected to produce 15 million kWh, but it has exceeded this estimate, having produced nearly 21.5 million kWh in 2006. The five-turbine project is the first wind farm in New Jersey and the largest coastal wind farm in the United States. The project had received $174,000 of funding under the Renewable Energy Project Grants and Financing Program as of the end of 2006. The project has been approved for a $1.7 million grant.

Burlington County applied for funding for a landfill gas project. Original plans were for a 4 MW project, but the applicant prepared and submitted engineering estimates identifying significant potential to expand the project to a total of 5 MW. As of the end of 2006 the project had not received any program funding. A project grant agreement has been developed and Clean Energy fund payments were expected to be made by the EDA upon presentation of itemized expenses. This project is scheduled for completion in 2007.

Renewable Energy Advanced Power Plant Program

The Grid Supply program was modified in 2004 to provide a more attractive incentive for large projects and was renamed the Renewable Energy Advanced Power Plants (REAP). REAP offered grants and low-interest financing to companies developing large-scale (>1 MW) renewable energy facilities. Grants were made available to offset up to 20% of project costs; low-interest rate bonds or loans are available for the remainder of project costs, although the borrower is required to make a minimum 10% equity contribution. For the financing portion of project support, the program guarantees to buy down the loan interest rate, or to lower the risk in the overall financing.

The New Jersey EDA manages program financing, working in cooperation with the BPU. The BPU manages technical aspects of the projects. Eligible renewable energy sources include wind, PV, landfill gas, digester gas, and methane from sustainable biomass, and qualifying projects are expected to supply electricity to the PJM Power Pool.

There were four project proposals submitted under the REAP program. The 1.6 MW Atlantic County Landfill Unit I project is operational and received a $513,225 grant in 2005. Total financing for that project is $1.6 million. Burlington County has applied for funding for an additional 1.9 MW unit at the site. Landfill gas projects in Ocean and Warren Counties were approved by the Board for funding in November, 2006. Neither project is operational yet. Rahway Valley Sewerage Authority (RVSA) applied for funding for a biogas project under this phase of the program as well. That project was approved by the Board during the first quarter of 2007.

Renewable Energy Project Grants and Financing Program (REPGFP)

In 2005, the REAP program was renamed the Renewable Energy Project Grants and Financing program to better reflect the nature of the program. Staff renegotiated award amounts for some projects based on reviews of applicants' project financials which indicated that applicants did not need financial support in order to facilitate development. And in 2006, staff stopped accepting applications. However, based on participant feedback, and given the limited amount of non-solar Class I resources that have been developed to date, significant barriers still exist for non-solar Class I resource development in New Jersey.

Note that the REPGF program grant for the 7.5 MW Jersey Atlantic Wind / Community Energy wind farm was calculated based on 4.875 MW of installed capacity. 2.625 MW received funding under the CORE program in early 2007. Since only funded capacity is counted in this market assessment, and to properly attribute capacity development across programs, only 4.875 MW of the wind farm has been attributed to the REPGF program, and 2.625 MW should be attributed to the CORE program in a future market assessment. However, since the full 7.5 MW project has been operational since the end of 2005, its total capacity and output have been counted in the market level assessment (using 2006 as the starting year since that was the year in which the project received its first incentive payment).

Table 3-30. Project Summary[106]

Contract	Financial Assistance	Project Type	Project Size (MW)	Estimated Annual Energy Generation (MWh)	Application Year	Year Approved	Project Status as of 12/31/06
Grid Supply							
Community Energy (CE)	$1,696,000 grant[107]	Wind	4.875	21,488	2002	2002	Operational but incentive not paid
Burlington County	$3,900,000 grant	Landfill Gas	6.15	46,000	2002	2002	Not operational, no incentive paid
Sub-Total Grid Supply	***$5,596,000***		***11.03***	***59,967***			
REAP Projects							
Atlantic County Landfill Gas	$513,225 grant; $1,600,000 EDA loan	Landfill Gas	1.6	12,516	2004	2005	Operational and incentive paid
Ocean County Landfill Gas	$1,500,000 grant; $15,000,000 EDA loan	Landfill Gas	9.6	71,902	2003	2006	Not operational, no incentive paid
Warren County Landfill Gas	$1,200,000 grant; $7,688,794 EDA loan	Landfill Gas	3.8	29,693	2005	2006	Not operational, no incentive paid
Rahway Valley Sewerage Authority	$500,000	Biogas	1.5	8,712	2005	2007	Not operational, no incentive paid
Sub-Total REAP Supply	***$3,713,225 (grants only)***		***16.5***	***122,823***			
Total Approved Projects	**$9,309,225**		**27.5**	**182,790**			

106 *Generation estimates from hardcopy project files provided by BPU; capacity values from "EDA CEP Funds vs Costs1-10-3-07".*

107 Only $173,759 of the total grant had been paid as of the end of 2006. The remainder was paid in early 2007.

3.3.2 Summary of Goals and Achievements

REPGFP PROGRAM GOAL	STATUS	ACHIEVED GOAL?
Process 6 applications in 2005.	Three applications were received in 2005 and one was approved.	No
Install 19 MW of RE systems in 2005.	1.6 MW were completed in 2005.	No
Initial application review completed within 30 days of receipt; evaluation of initial application by evaluation team completed in 90 days; issue grant payments within 30 days of final approvals.	Application reviews were completed in 30 days. Evaluations done by the DEP and EDA took 60 to 120 days. No projects received final approvals in 2005.	Yes

3.3.3 Program Performance Indicators

The REPGFP program indicators are listed below.

1. Number of applications received
2. Number of applications processed
3. Number of participating RE installations (diversity of technologies)
4. Dollar value of grants/financing awarded (average annual and cumulative)
5. Distribution of end-use customer facility types
6. Annual RE capacity from participating RE systems (by project size & RE type)
7. Annual RE generation from participating RE systems (by project size & RE type)
8. Awareness of program by potential participants
9. Number of days to process applications
10. Cumulative avoided environmental impacts

The indicators, the relationship to the program-specific goals, and the results from the analysis are shown below.

Indicator #1: Number of applications received

Indicator #2: Number of applications processed

Relationship to Program-Specific Goals: Approve 6 applications in 2005.

The goal to approve six applications in 2005 was not met because the solicitation was put on hold. Table 3-31 presents the number of applications in the REPGF program, including the earlier versions of the program, Grid Supply and REAP. To the knowledge of the Summit Blue Team, all applications were processed by the BPU.

Table 3-31. Number of Program Applications and Approved Projects

Year	Number of program Applications Processed	Number of Approved Projects
2002	5	2
2003	2	0
2004	0	0
2005	2	1
2006	0	2
Total as of 12/31/2006	9	5

The Rahway Valley Sewerage Authority Biogas project is not included in Table 3-31. This project was approved by the Board in 2007.

Indicator #3: Number of participating RE installations

Relationship to program-Specific Goals: Install 19 MW of RE systems in 2005.

Through 2006, the participating renewable energy projects included wind, landfill gas, and biogas facilities. The number of projects by technology is presented in Table 3-32.

Table 3-32. Number of Participating Renewable Energy Systems

	Wind	Landfill Gas	BioGas
Complete	1	1	
Approved		3	
Pending			1
12/31/06 Total	1	4	1

Indicator #4: Dollar value of grants/financing awarded (annual and cumulative)

Relationship to program-Specific Goals: Approve 6 applications in 2005.

Table 3-33 shows the dollar value of the grants paid as of December 31, 2006. The total value of incentives paid through December 2006 was $686,984.

Table 3-33. Dollar Value of Grants Paid

Year	Annual
2002	-
2003	-
2004	-
2005	$513,225
2006	$173,759
Total as of 12/31/06	$686,984

Indicator #5: Distribution of end-use customer facility types

Relationship to program-Specific Goals: Approve 6 applications in 2005.

All projects funded under the program have been at municipally-owned sites.

Indicator #6: Annual renewable energy capacity from participating systems

Relationship to Goals: Install 19 MW of other (non-solar) RE systems in 2005.

As of December 2006, approximately 6.5 MW of renewable energy capacity has been completed (installed and paid) under the REPGFP program (Table 3-34), 1.6 MW of which was completed in 2005. The goal for the REPGFP was to install 19 MW in 2005.

Table 3-34. Capacity from Participating Systems by Renewable Energy Type (MW)

Completed (Paid) Year	Wind	Landfill Gas	Biogas	Total
2002	-	-	-	0
2003	-	-	-	0
2004	-	-	-	0
2005	-	1.6	-	1.6
2006	4.875	-	-	4.875
Total as of 12/31/06	4.875	1.6	-	6.475

Indicator #7: Annual RE generation from participating RE systems

Relationship to Overall BPU Goals: Install 19 MW of other RE systems in 2005.

Total annual generation from projects completed as of 12/31/06 is estimated to be approximately 26,500 MWh per year. Based on 2006 performance, the portion of the 7.5 MW wind farm attributable to REPGF funding produced 13,967 MWh in 2006, and the 1.6 MW landfill gas project can produce 12,500 MWh annually.[108]

Table 3-35. Annual Energy from Participating Systems by Renewable Energy Type (MWh)

Completed Year	Wind	Landfill Gas	Biogas	Total
2002	-	-	-	-
2003	-	-	-	-
2004	-	-	-	-
2005	-	12,516	-	12,516
2006	13,967,	12,516	-	26,483
Total annual generation for systems completed as of 12/31/2006	13,967	25,032	0	38,999

Indicator #8: End-use customer awareness of program

Relationship to Overall BPU Goals: By December 31, 2008, install 300 MW of Class I renewable energy generation capacity in NJ.

While some developers are very familiar with the BPU and its programs, for those with less experience in the New Jersey market, outreach mechanisms and informational resources associated with the program have been insufficient. The two applicants interviewed for the project indicated that the BPU could benefit from additional efforts to respond to inquiries regarding program specifics, both for potential applicants and those with projects already in the development pipeline.

Indicator #9: Number of days to process applications

Relationship to program-Specific Goals: Initial application review completed in 30 days of receipt; evaluation of initial application by evaluation team completed in 90 days; and issue grant payments within 30 days of final approvals.

The project tracking spreadsheet does not include sufficient information to track this indicator. However, the 2005 program evaluation by Rutgers indicates that the application reviews were completed in 30 days and the evaluations of the applications done by the DEP and EDA took 60 to 120 days. No projects received final approvals in 2005.

The two program participants interviewed reported that the application review and incentive payment processes are slow and that there have been substantial project delays. While permitting issues

[108] These are first year savings estimates. The generation from landfill gas projects declines over the life of the project.

contribute to these delays, participants believe that the BPU would benefit from additional program staffing to ensure an appropriate level of program management activity.

Indicator #10: Cumulative avoided environmental impacts

Relationship to Program-Specific Goals: None listed.

Renewable energy installations funded through the REPGFP program from 2002 through 2006, can be attributed with avoiding the emission of 50 tons of nitrous oxides, 115 tons of sulfur dioxide, 26,884 tons of carbon dioxide, and 0.0006 tons of mercury (Table 3-36).[109] Avoiding this amount of carbon dioxide emissions is equivalent to taking nearly 5,000 cars off the road for one year, or preserving 188 acres of forest from deforestation.

Table 3-36. Cumulative Avoided Environmental Impacts (Metric Tons)

Year	NOx	SO_2	CO_2	Hg
2005	16	37	8,628	0.0002
2006	34	78	18,256	0.0004
total cumulative through 12/31/06	50	115	26,884	0.0006

3.3.4 Assessment of Program Structure and Implementation

Of the five projects that had been approved for funding under the program to through 2006, two participating developers agreed to participate in in-depth interviews, as well as one project owner. One of the developers is managing two of the program's approved projects (one completed project and one incomplete), and the other developer is managing a project that is not yet complete, and has not received funding. The results of these interviews are presented here. Feedback from an interview with a representative from the Economic Development Authority, the entity that manages program financing, is also included in this section.

Program Structure Review

Interviewees indicated that the application requirements are onerous and the lengthy technical review process limits the quality and quantity of applicants. One interviewee reported:

- *Complicated paperwork and reporting. The criteria for approval were vague. We weren't sure what was being measured.*

[109] This includes the full generation of the 7.5 MW wind farm, which received incentives from both the REPGFP and the CORE program. This project does not show up in the CORE database, so it does not appear that avoided environmental impacts are being double counted.

The program is structured so that grant funding is capped at 20% of eligible project development costs. Participants were asked about the effects this incentive structure has had on project development. The comments below show that the cap and the timing of financial assistance is a limitation for some projects. However, one program participant noted that public projects finance with bonds and that availability of upfront funding is not an issue.

- *They are giving PV 60% of first costs. If we got 60%, there would be a lot more landfill plants built and other innovative projects.*
- *If we had more upfront cash, it would reduce risk and we could have developed a lot more projects. If they would structure the grant so you could receive a larger percentage upfront in the form of a loan and pay it back with actual kWh production, you'd get a lot more projects. Give us 30% of construction costs – not just 20%, and make sure we get at least 20% of that number upfront in cash.*
- *Usually these projects are sized by the amount of gas coming out of a landfill. A higher cap could only help other projects come to market.*
- *Don't wait until the project is up and running to issue the grant. Make that upfront money payable back to the BPU if the project does not get built.*
- If the incentive cap was modified or removed, how many more projects per year/additional capacity could you develop? - *50 more projects, and 5000 additional kW.*

The comments of one developer show that the grants offered through the program can provide an effective incentive and can get some projects moving sooner than they might in the absence of an incentive.

- *I think a little financial help gives people an incentive to take risks on innovative technologies.*
- *The Grant helped us move more quickly, and it allowed the project to get developed sooner.*

However, in contrast to the comments of that developer, one program participant explained:

- *We would have gone forward with the project at the same pace, at the same size, to make full use of the methane.*

The other developer interviewed also commented that his particular project would have moved forward without any differences in size if program funding had not been available.

One participant commented that the BPU focuses too much on solar, and that a new carbon reduction approach should be developed that goes beyond solar.

There were some comments that the level of incentive actually paid out through the program sometimes varied from the advertised rate of 20%. This 20% level was not always approved, and so prospective developers are not sure about what to expect in terms of the actual incentive they will receive.

Program Management and Implementation Review

The participants who were interviewed expressed considerable frustration with the application process, the slow pace of project approval, and the availability of program staff. Some of their comments are highlighted below.

- *I never really had a direct relationship with anyone at BPU – it was always through attorneys or consultants. A single point of contact at BPU would have certainly been better. I often did not know what needed to happen, as a lot of this was handled by consultants.*
- *The paperwork and application process could be simplified. It takes a lot of work and time to prepare the application, over $10,000. And the criteria should be made more specific.*
- *They have a long application process, and they seem under-staffed to perform application reviews. Then there seems to be a long process to get the commission to review it.*

However, one participating developer noted that the process of developing a large project is inherently slow. He recognized that certain steps in his project's development, like permitting, took a great deal of time and were beyond the control of program staff.

The overall satisfaction with the program was mixed. Satisfaction ratings from the two participating developers are shown in Table 3-37. Satisfaction was measured on a scale of 1 (very unsatisfied) to 5 (very satisfied).

Table 3-37. Summary of Participant Satisfaction with REPGF Program Elements

	Participant 1	Participant 2
Eligibility of RE Systems	1 (too narrow)	4
Project Financial Incentive Level	3	4
program Application Process	2	3
program Staff Support	1	2
Incentive Payment Process	1	2
Overall Satisfaction	3	3

The lowest ranking was for program staff support and incentive payment process, which reflects the comments shown above. The highest score was for project financial incentive level.

Marketing and Outreach

A detailed review of marketing activities and materials was not completed as part of this assessment. Therefore, it is not possible to put forth a detailed assessment of the program's market efforts. However, developers were asked about program marketing and outreach, and their feedback is presented here. The program is no longer being marketed as it is on hold and not currently accepting applications. Program marketing during the period when it was open for applications was not rated highly. Participating developers were unhappy with the BPU's emphasis on solar, and on marketing to smaller players in the market as indicated by the comments below.

- *They have a Clean Energy Award program – it is always solar. All the publicity they do is about solar. They should promote methane gas solutions, too, and give it recognition.*
- *New Jersey's programs, are marketed well to homeowners and business-owners. But government entities might not have been made fully aware of all the programs and what they offered.*
- *It is hard to find out what programs are available or what is needed from the website.*

These comments point to the need for an improvement in the way the program is marketed once it becomes active again, both the availability and quality of information about the program, and the channels for making potential participants aware of the program's existence. In addition, it seems clear that the BPU must make a concerted effort to support non-solar technologies and recognize their importance in facilitating cost-effective fulfillment of RPS requirements.

Barriers to Development of Large, Non-Solar Projects

As explained above, participating program developers reported that more renewable energy project construction would occur, and it would occur faster, if the REPGF program incentive levels were increased and if funding were provided prior to project construction. The REPGF program developers interviewed also expressed frustration with the BPU's heavy emphasis on solar. One interviewee urged the state to treat RECs from all renewable projects equally.

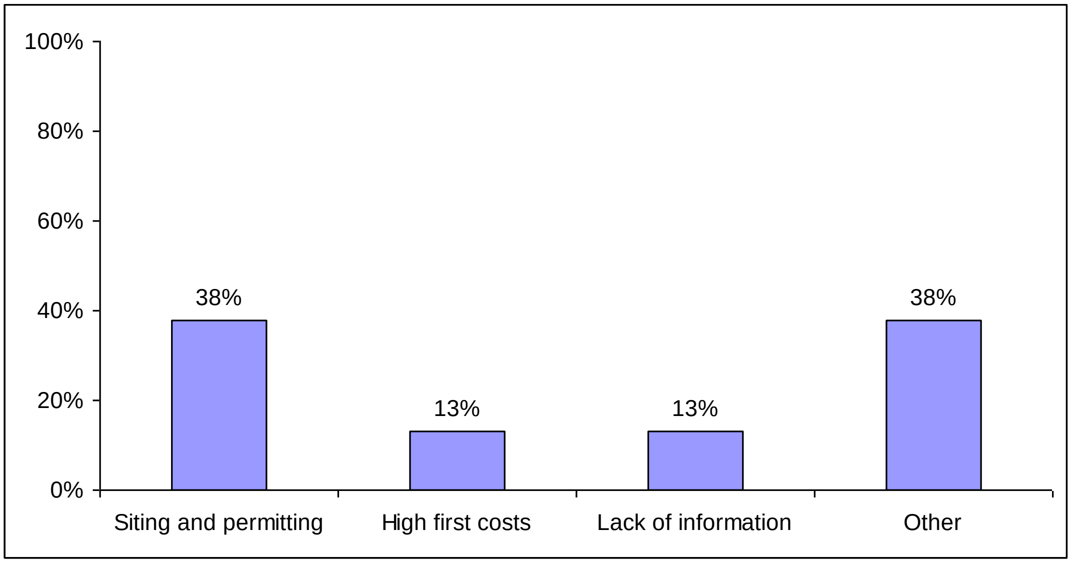
- *RECs should be allowed to go where the markets will take them. There is almost no interest given to methane power plants (landfill, sewage treatment, digester gas, biomass). Methane is almost ignored in New Jersey, compared to solar, when it could help meet the RPS much more quickly.*

One developer noted that landfill gas projects have many benefits such as odor abatement, and economic benefits, but that an important and increasing barrier to landfill gas development is the limited availability of landfills that have not yet been tapped for energy production. He noted that the potential for development of existing landfills could be increased if leachate water were re-introduced into the landfills to increase the recovery of gas.

CORE program developers were also asked about barriers to large renewable energy project development in New Jersey, as were developers not participating in any New Jersey clean energy programs. Key barriers discussed by developers participating in the CORE program included uncertainty about program incentives and long-term REC values, and the long bureaucratic processes and inability to contact the BPU to get questions answered or rules clarified. Respondents also mentioned siting and permitting restraints and uncertainty regarding the future of federal tax incentives.

Non-participating developers explained that siting is difficult for large-scale wind and landfill gas in New Jersey and that the permitting cycle is very long (Figure 3-12).

Figure 3-12. Non-Participant Developers' Top Barriers to Large-Scale Projects



Source : CORE non-participant developer survey

A more complete discussion of barriers to large renewable energy project development is included in the market-level assessment in Volume 2, Section 2.

3.3.5 Summary of Program Performance

The program was designed to meet the following goals:

- Promote large-scale grid connected renewable energy projects in New Jersey.
- Promote competition among technologies.
- Encourage cost effective renewable grid supply technologies.
- Facilitate the development of a thriving, diversified renewable energy market.

The program has made progress toward some of these goals. A total of 9.1 MW of large-scale renewable energy capacity has been installed through the program, and an additional 21 MW has been approved and is under development. Not all of this capacity can be attributed directly to the program, but developer input indicates that the grants have sped up the pace of installation and may enable some of the projects to be developed that would not otherwise occur.

The technologies that were installed through the program were cost-effective for the BPU. The table below shows the amount of grant paid out by the BPU for each MW of installed capacity related to both completed and approved projects.

Table 3-38. Summary of Project Incentive Expenditure Per Watt of Installed Capacity (Both Completed and Approved Projects)

Project Name	Capacity (MW)	Grant ($)	Grant $ / Watt
Grid Supply Projects			
Community Energy / Jersey Atlantic Wind	4.875	$1,696,000	$0.35[110]
Burlington County Landfill Gas	5[111]	$3,900,000	$0.78
REAP Projects			
Atlantic County Utility Authority Landfill Gas	1.6	$513,225	$0.27
Ocean County Landfill Gas	9.6	$1,500,000	$0.16
Warren County LFG	3.8	$1,200,000	$0.32
Rahway Valley Sewerage Authority	1.5	$500,000	$0.33
Total / Average	**26**	**$9,309,225**	$0.37

This average value of $0.37 per Watt is almost 10 times less than the average value of $3.88 per installed Watt for the CORE program, in which 87% of installed capacity funded under the program through 2006 is PV. This shows that the investments made through the REPGF program are a much more cost effective means of increasing installed renewable energy capacity than investments made to date through the CORE program.

The goals of promoting competition among technologies and facilitating a thriving and diversified RE market are difficult to evaluate. So far, the program has not actively promoted specific technologies but has been open to applications for a range of technologies. The fact that the program was suspended because the applications being received were deemed financially viable without the program indicates that the proposals were for well-established RE technologies that do not need a rebate in today's energy market conditions. Therefore, the BPU should adapt program outreach efforts and target specific technologies requiring the greatest assistance.

One of the most cost-effective and mature RE technologies for New Jersey is landfill gas, and this technology represents 81% of the capacity installed through the program to date. If *rapid* development of RE capacity is the goal, then this disproportionate level of support for LFG is appropriate. However, the approach taken so far has proved limited in promoting a diversified renewable energy market in New Jersey. Also, it should be noted that there is limited potential for future development of this technology as many of the existing landfills are tapped and old landfills will taper off in output.

[110] This value pertains to the total grant amount for which the project was approved. However, only $173,759 was paid in 2006.

[111] Total project is 6.15 MW but 1.1 will be used for onsite and REPGF program funding based on 5.05 MW size.

Additional Class I eligible technologies exist, and can play an important role in enabling New Jersey to achieve its RPS requirements. Renewable energy resources that have large potential in New Jersey but which may not be viable without a rebate include the following: offshore wind, biomass/solid waste gasification, biomass/solid waste direct combustion, food waste anaerobic digestion, and utility-scale PV. Therefore, alternative strategies should be explored to ensure that a greater diversity of projects receive support through the REPGF program.

3.3.6 Recommendations

Based on a review of program records and interviews with program participants, the following set of recommendations was developed.

1) Implement a **two-tier incentive level**. Facilitate expeditious deployment of more mature technologies, such as landfill gas, by providing them a base ("benchmark") incentive level. Meanwhile, target development of technologies that are currently less cost-effective and provide these projects with a higher level of financial support (see Volume I Section 5 for further details). The incentive levels recommended below would be the initial benchmark incentive levels, and would be used for long-term planning purposes for the next SBC funding cycle, but should be updated annually to factor in changing market conditions. An adder of approximately 15% should be applied for higher priority project funding to expedite project activity.

2) An annual program budget of $50.2 million is recommended. The incentive levels and recommended program budget are based on analysis which considered New Jersey's renewable energy development needs, by technology, in order to stay on track to achieve RPS requirements through the next SBC funding cycle. The analysis also factored in project costs and barriers, and an IRR target of 12% was used. Discussion of the basis for these recommended incentive levels is provided in the portfolio level assessment, Volume 1, Section 5.

3) In the past, projects have received a combination of grant and finance-based support. It is recommended that a similar approach be used in the future, but using the incentive "benchmark" or "benchmark plus adder" as the maximum incentive value for which an applicant would be eligible. As noted above, the Board should update the benchmark and "adder" incentive levels annually based on current market data in an effort to match program incentives to evolving market conditions. The Board should consider making grant payments in increments, with part paid upfront, and additional payments paid based on performance milestones. The Board should also consider adding a competitive solicitation component to the program, as this would help stimulate competition among projects which could help lower costs and provide an annual snapshot of market conditions. It would also provide focus for program outreach activities, and may improve program efficiency. Whatever the policy the BPU decides upon, it should be clearly communicated in a program handbook and policies.

4) A ***pre-development assistance*** component should also be added to the REPGF program to help reduce the risks and costs associated with feasibility assessment and non-construction pre-development activities (i.e., siting, permitting, potential delays in the development cycle) associated with utility-scale non-solar projects. Funding and/or technical support should be provided to help developers. This support is particularly important for developers working with less mature technologies for which the development path is less well defined than for more mainstream renewables.

5) **Streamline the application process and program materials**. Provide step-by-step directions for applicants, and clearly define the requirements for acceptance in the program. Communicate incentive levels to applicants upfront so developers know what to expect from the program.
6) Provide sufficient **program staff resources** to promptly and effectively respond to applicant inquiries, and to shorten the approval process. Set and clearly communicate a target for the maximum length of time the process should take so that expectations are clear both for program staff and applicants.
7) **Eliminate the incentive cap** (i.e. percent of total project costs that can be covered by the program incentive) and instead base incentives on the recommended incentive levels set forth in this report. The recommended incentive levels were based on an analysis of project incentive needs to achieve a 12% IRR. Assumptions should be updated in the future to reflect changing market conditions. However, project funding should not be limited by an incentive cap if the goal is to trigger significant development of large projects. Large-scale projects are very cost-effective compared to the small scale projects installed through the CORE program, and substantial development of these larger-scale projects will help minimize the ratepayer impacts associated with achieving New Jersey's RPS requirements.
8) Actively **target specific technologies**, especially those requiring the most help to be implemented, such as offshore wind, biomass/solid waste gasification, biomass/solid waste direct combustion, food waste anaerobic digestion.
9) Support the development of **technology-focused networking / working groups** focusing on biomass, and potentially some emerging technologies as well, to foster the transfer of information and market development ideas across businesses facing similar challenges in the marketplace.
10) Research the status of projects that applied for, but were turned down for funding due to the assumption that they did not require financial support. If these projects were not developed in the absence of program support, representatives from the projects may be able to provide valuable insights into non-financial development barriers that the program should address in the future.[112]

3.4 Renewable Energy Business Venture Assistance Program

3.4.1 Program Performance

This program commenced in 2001, and was initially known as the Market Infrastructure Development program (MIDP). In 2003, the name was changed to the Renewable Energy Economic Development program (REED), and in 2004, the name of the program was changed to the Renewable Energy Business Venture Assistance program (REBVAP).

[112] Project applicants that were denied funding were not interviewed as part of the assessment both due to lack of data, and lack of sufficient resources given the emphasis on the CORE participant survey and in-depth developer interviews.

2003 REED Solicitation[113]

In January 2003, the Board announced a competitive solicitation to provide funding for the development of renewable energy businesses, technologies and market infrastructure in New Jersey. The goal of the program was to leverage public and private funding for the purpose of advancing the technologies and services necessary to support a thriving renewable energy industry in the state. The amount of funding available for this solicitation was $2.7 million.

In 2003, just under $2.7 million in grant funding was awarded to ten renewable energy businesses. Final grant agreements were reached with nine of the businesses and one declined the award. Grant funding issued under this phase of the program totaled $2,501,629. The average grant amount was approximately $280,000. Three of the projects were PV related; three were related to general market building activities including education and training; two were hydrogen-related; one was wave-power related, and the remainder pertained to monitoring of system performance and power conditioning.

2004 REED Program Revisions

In 2004, the Board revamped the program. The revised program is open to all applicants that seek funding for research, business development, commercialization, and technology demonstrations of innovative products or services that advance the delivery of renewable energy systems to the marketplace. The BPU sought applications that demonstrated a clear path to advancing the cost-effective implementation of renewable energy technologies and services, and that would establish a dynamic business infrastructure within the renewable energy industry.

For the 2004 REED solicitation, $6.35 million in recoverable grant funds were made available. Applicants that are awarded grants are required to pay back the grant once their business venture starts generating revenue. Nine proposals were submitted in response to the 2004 solicitation requesting a total of $3.14 million. Seven proposals were rejected, and the other two were reviewed by the EDA. The BPU received favorable EDA recommendations for those two projects in October 2005, and in February 2006, the Board approved $763,429 in recoverable grant awards for these two projects. Only one of these awards was paid. The grantee was funded to develop PV inverter technology. The other approved project was for a hydrogen fuel storage device, but the project has not been funded to date.

Renewable Energy Business Venture Assistance Program

On October 21, 2005, the BPU released a new solicitation called the Renewable Energy Business Venture Assistance program. This version of the program has a grant component for demonstration projects and a recoverable grant component for products and services close to commercialization. Five million dollars of funding was made available for the initial solicitation, split evenly between the two program components.

The BPU received 15 project proposals in 2005 in response to this solicitation. Thirteen applicants requested grants, one requested a recoverable grant and another requested both. Three additional proposals for recoverable grants were received in the first half of 2006. Eight of the projects were sent denial letters in 2006 due to the proposals not meeting the program's minimum requirements. An

[113] These projects are categorized as Market Infrastructure Development Projects in BPU contract records.

evaluation team headed by the NJDEP began evaluating the remaining project proposals in the second quarter of 2006.

In 2005, $2.2 million of the money budgeted for the Renewable Energy Business Venture Assistance program was loaned to PJM Environmental Information Services, Inc. (PJM EIS), to finance the capital costs for the Generation Attributes Tracking System (GATS). GATS is a regional information system, managed by PJM-EIS, that tracks the environmental attributes of generation, and supports reporting and verification requirements related to environmental compliance and associated markets. The GATS system went on line in September, 2005.

3.4.2 Summary of Goals and Achievements

REPGFP PROGRAM OBJECTIVES	STATUS	ACHIEVED GOAL?
Approve 10 applications in 2005.	No applications were approved in 2005 although, as noted above, 18 proposals were submitted in response to the solicitation and 10 have been sent to the evaluation committee for review.	No
BPU completes initial review of applications in 30 days.	The initial reviews were completed in 30 days.	Yes
Evaluation of applications completed by evaluation team in 90 days.	Due to the closing of the DOE Mid-Atlantic Office and the time it took to replace them with the Oak Ridge Lab, this goal was not met.	No
Approve applications that support 4 different technologies.	Projects funded under the 2003 solicitation included hydrogen, wave, PV and one related to power conditioning for a variety of technology applications.	Yes
Leverage $3 in private capital for every dollar of program funds allocated to the program.	Insufficient data available	N/A
Locate 5 new renewable energy businesses in New Jersey.	While no projects were funded through the 2005 solicitation, 10 businesses received grants through 2004, and all have offices in New Jersey.	Yes

3.4.3 List of Indicators

The REBVAP program indicators are listed below.

1. Number of program applications
2. Number of processed applications
3. Number of projects that include third party investors

4. Dollar value of grants awarded (average annual and cumulative)
5. Number of grants repaid
6. Number of jobs created in RE industry in NJ
7. Number of new RE businesses that locate in NJ (with and without project grant funding)
8. Annual amount of private capital leveraged through participating projects
9. Product output by participating RE businesses (amount of RE products manufactured in NJ)
10. Awareness of program by potential applicant pool
11. Initial application review period
12. Technical committee application review period
13. Distribution of technologies supported

3.4.4 Assessment of Results

The indicators, their relationship to the program-specific or overall the BPU goals, and the results from the analysis are presented below.

Indicator #1: Number of program applications

Indicator #2: Number of processed applications

Relationship to program-Specific Goals: Approve 10 applications in 2005.

Under the 2003 REED program, 10 proposals were submitted and approved; however, one project dropped out after approval.

Under the 2004 REED program, nine proposals were submitted and two projects were approved.

No applications were *approved* in 2005 although, as noted above, 18 proposals were *received* in 2005 and 2006, submitted in response to the REBVAP solicitation, and 10 were sent to the evaluation committee for review.

Table 3-39. Number of program Applications and Approved Projects

Year	Number of program Applications	Number of Approved Projects
2003	10	9
2004	9	2
2005	15	Pending
2006	3	Pending
Total as of 12/2006	37	11

Indicator #3: Number of projects that include third party investors

Relationship to program-Specific Goals: Leverage $3 in private capital for every dollar of program funds allocated to the program.

The details of the businesses that were awarded the grants were not provided. Company financials and operating structure would be needed to track progress toward leveraging private capital.

Indicator #4: Dollar value of grants/financing awarded (average annual and cumulative)

Relationship to Goals: This indicator is related to the BPU's overall goal of advancing the development of the renewable energy industry in New Jersey, and, indirectly, to the program-specific goal of approving 10 projects in 2005.

Table 3-40 shows the cumulative annual dollar value of the incentives processed. The cumulative annual dollar amount of incentives approved has increased from 2003 to 2006 as the funding commitments made under the program in 2003 and 2004 continue to be paid out.

Table 3-40. Cumulative Annual Dollar Value of Grants and Incentives Processed

Year	Cumulative Annual Dollar Value of Grants and Incentives Processed
2003	$2,501,629
2004	$2,765,058
2005	$4,985,058[114]
2006	$4,985,058

Indicator #5: Number of grants repaid

Relationship to Goals: This indicator is related to the BPU's overall goal of advancing the development of the renewable energy industry in New Jersey, as grant repayment demonstrates success of the funded ventures.

Data was not provided.

Indicator #6: Number of jobs created in renewable energy industry in New Jersey

Relationship to Goals: This indicator is related to the BPU's overall goal of advancing the development of the renewable energy industry in New Jersey, and, indirectly, to the program-specific goal of establishing five new renewable energy businesses in New Jersey.

[114] A loan of $2,222,000 was made in 2005 to PLM Environmental Information System (PJM EIS) to finance the capital costs for the Generation Attributes Tracking System (GATS). PJM EIS was expected to begin paying the loan back with interest in October 2006.

The calculation of this indicator has not been completed, as it is dependent on the availability of baseline data, and additional data on projects funded through the program. As described in the 2005 Program Evaluation Report by the CEEEP, the establishment of the baseline was one of the 2005 program goals to be completed by program staff and has not yet occurred.[115] Now that the program management has transitioned to the Renewable Energy Market Managers, CEEEP expects that they will be developing the new renewable energy jobs baseline to which the impacts of this program can be compared.[116]

Indicator #7: Number of new renewable energy businesses that locate in New Jersey (with and without project grant funding)

Relationship to program-Specific Goals: Locate five new renewable energy businesses in New Jersey.

The calculation of this indicator has not been completed, as it is dependent on the availability of baseline data. However, ten projects receiving funding under the program since its inception have offices in New Jersey.

As described in the 2005 Program Evaluation Report by the CEEEP, the establishment of the baseline was one of the 2005 goals to be completed by program staff and this has not yet occurred.[117] Now that the program management has transitioned to the Renewable Energy Market Managers, CEEEP expects that the Market Managers will develop the new renewable energy businesses baseline to which the impacts of this program can be compared.[118]

Indicator #8: Annual amount of private capital leveraged through participating projects

Relationship to program-Specific Goals: Leverage $3 in private capital for every dollar of program funds allocated to the program.

The details of the businesses awarded the grants was not provided. Company financials and operating structure would be needed to track progress towards leverage private capital.

Indicator #9: Product output by participating RE businesses

Relationship to Goals: This indicator is related to the BPU's overall goal of advancing the development of the renewable energy industry in New Jersey, as strong product output by participating RE businesses demonstrates industry growth resulting from program funding.

The Summit Blue team did not collect data to calculate this indicator because insufficient baseline data existed, and primary data collection efforts were focused on other programs. As described in the 2005 Program Evaluation Report by the CEEEP, the establishment of a baseline was one of the tasks

115 The Center for Energy, Economic and Environmental Policy (CEEEP), "2005 Program Evaluation, New Jersey's Clean Energy Program, Energy Efficiency and Renewable Energy Programs", September 2006, page 67.

116 Ibid.

117 Ibid.

118 Ibid.

to be completed by the program.[119] Now that the program management has transitioned to the Renewable Energy Market Managers, CEEEP expects that they will be developing the renewable energy production baseline to which the impacts of this program can be compared.[120]

Indicator #10: Awareness of program by potential applicant pool

Relationship to program-Specific Goals: Approve 10 applications in 2005, and fund projects that support four different technologies.

Surveys of the REBVAP end-use customers were not included as part of the Renewable Energy Market Assessment. The survey efforts of this market assessment focused on the programs that are currently delivering verifiable energy generation. As this program matures, it is recommended that end-use customer surveys be conducted.

Indicator #11: BPU Application review period

Relationship to program-Specific Goals: BPU completes initial review of application in 30 days.

The initial reviews were completed in 30 days.

Indicator #12: Technical committee application review period

Relationship to program-Specific Goals: Evaluation of initial applications completed by evaluation team in 90 days.

The DOE Mid-Atlantic office has played a key role on the technical review committee in the past. Due to the closing of the DOE Mid-Atlantic Office, and the time it took to replace them with the Oak Ridge Lab, this goal was not met. It is anticipated that the new Renewable Energy Market Managers will work to ensure that future interruptions of the application process will be minimal.

Indicator #13: Distribution of Technologies Supported

Relationship to program-Specific Goals: Approve applications that support four different technologies.

In 2003, four different technologies were supported; however, 56% of these projects were PV related projects. Numbers were not available for 2005 and 2006 since the applications are pending technical review. Table 3-41 presents the project distribution by technologies for 2003 and 2004.

[119] Ibid.

[120] Ibid.

Table 3-41. Distribution of Technologies Support

	PV	RE Fuel Cell	Wave/Tidal	Hydrogen	Total
2003	5	2	1	1	9
2004	1			1	2
2005	applications pending				
2006	applications pending				
Total	6	2	1	2	11

3.4.5 Assessment of Program Structure and Implementation

Program Delivery Review

No surveys of either participants or non-participants were done for the program. However, an analysis of the project applications received indicates a significant level of interest in the program from the renewable energy industry.

Table 3-42 shows the number of applications received and approved in each year. In the case of 2005 projects, which are the proposals submitted in response to the October 2005 Solicitation, nine of these have not yet been given final approval but have been through the initial stages of the approval process and are now being reviewed by the technical committee. The projects listed as "under review" have not been rejected. They were sent but have not yet been sent to the technical committee and are flagged as needing further discussion.

Table 3-42. Number of Applications Received and Approved

Year	Total Received	Approved/Pending	Under Review	Not Approved	Paid
2003	33	10		23	9
2004	9	2		7	1
2005	18	9*	3	6	1

** Pending final approval*

The total number of applications received dropped from the initial high number of 33 in 2003, to 9 in 2004 and 18 in 2005. The solicitation in 2005 included options for applicants to apply for both recoverable and non-recoverable grants. Of the 12 projects that were not rejected after the initial review, the total value of grants applied for was $1,071,075 in recoverable grants, and $3,507,776 in non-recoverable grants.

The percentage of projects that were approved, out of the total received, ranges from 22% to 50% by year and is 35% over the three years. These figures show that there is enough interest in the program from industry to indicate that the program is being marketed sufficiently. In addition, the application requirements of the program are being met by at least 35% of applicants.

During the three years in which the program received funding applications the categories of applications received were widely distributed across the main areas of the renewable energy industry, as shown in Table 3-43. Over the three years, the highest percentage of applications was for projects related to PV (30%) followed by hydrogen-related technologies (12%), and general renewable energy (11%). Although PV had the highest share in all three years, thin film PV comprised a much larger percentage of applications in 2005, reflecting the growing market share and interest in this technology.

Table 3-43. Categories of Applications Received, 2003-2005

Category	2003	2004	2005	All Years
Biodiesel			7%	2%
Biomass	12%			7%
Education	12%		7%	9%
Fuel Cell	3%	11%		4%
General	12%		13%	11%
Hydrogen	15%	22%		12%
PV	27%	44%	27%	30%
PV thin film	3%		20%	7%
PV/Wind	3%			2%
Solar Heliostat			7%	2%
Transportation			7%	2%
Wave/Tidal	6%		7%	5%
Wind	6%	22%	7%	9%

Table 3-44 shows the percentage of projects accepted in 2003 and 2004 by category. It can be seen that the percentages of projects accepted by category are not the same as the percentages of applications received, with PV-related projects representing 33% of accepted applications, hydrogen-related projects representing 33%, and education-related projects representing 17% of the total number of accepted applications.

The funding allocation across technologies varied as well. The largest amount of funding has gone to hydrogen-related projects (33%), followed by PV (26%).

Table 3-44. Projects Accepted, 2003-2004

	Number of Projects	Percentage of Accepted Applications	Funds	Funds Percentage
Hydrogen	4	33%	$1,141,660	33%
PV	4	33%	$884,017	26%
Education	2	17%	$435,895	13%
PV Thin Film	1	8%	$500,000	14%
Wave/Tidal	1	8%	$499,486	14%

Similar statistics for the projects currently pending approval for 2005 show a different trend (Table 3-45). For the 2005 solicitation, PV thin film represents the largest percentage of both project applications and funding requested (33% of projects, and 48% of funding). This is followed by other PV projects, at 22% of projects and 24% of funding. Note that these figures include both recoverable and non-recoverable funds.

Table 3-45. Projects Pending Approval (2005)

	Number of Applications	Percentage of Applications Pending Approval	Funds Requested	Funds Requested Percentage of Total
Biodiesel	1	11%	$500,000	16%
General	1	11%	$152,595	5%
PV	2	22%	$750,000	24%
PV Thin Film	3	33%	$1,491,242	48%
Solar Heliostat	1	11%	$50,000	2%
Wave/tidal	1	11%	$188,000	6%

Marketing Assessment

There is no specific information available on the marketing of the program.

The current solicitation can be easily located on the BPU website, along with a facts sheet for quick reference. Guidelines for applicants and requirements for participation appear to be clearly defined in the solicitation, along with the application forms.

3.4.6 Summary of Program Performance

The program was designed with the following parameters:

1. Fund research, development, deployment, seed funding and commercialization activities to advance Class I Renewable Energy development in New Jersey.

2. Leverage public and private resources advancing the technologies and services necessary to support a vibrant renewable energy industry in New Jersey.

3. Support projects that demonstrate innovations in renewable energy technologies, services, system integration, financing, supporting systems and/or fuels.

4. Provide grants and recoverable grants for the development of businesses, technologies, services, and market infrastructure in support of furthering a thriving renewable energy industry in New Jersey.

The Renewable Energy Business Venture Assistance program appears to have had success in supporting the development of several emerging renewable energy technologies, or technologies that support renewable energy installations. This type of investment is essential when any new industry is starting up. The program has also funded two educational projects.

The evaluation team does not have any information on the direct results of the 12 projects that were funded in 2003 and 2004, some of which have now been completed. Descriptions of the funded projects from 2003 and 2004 are provided in Table 3-46.

Table 3-46. Summary of Projects Funded to Date

Category	Project Description
Education	Demonstration of solar electric systems on houses of worship and education, and outreach programs once installed.
Education	Education campaign to do outreach to local government officials to include green power in aggregated power purchases.
Hydrogen	Development of thermochemical hydrogen technology and the demonstration of the technology in a pilot scale solid oxide fuel cell.
Hydrogen	Demonstration and commercialization of an integrated system that produces hydrogen from photovoltaic panels, onsite hydrogen storage and fuel cell integration. This system will provide the complete power for a typical home and has multiple off-grid applications.
Hydrogen	Development of a power conditioner that will allow solar electric and wind power to be used in electrolyzers for the generation of hydrogen.
Hydrogen	This V- cell technology will provide cost-effective storage of both renewably generated electricity and hydrogen fuels. The V-cell can provide renewable power when and where it is needed from intermittent power resources such as sun, wind and water. This is also the next phase from the applicant's 2003 REED awarded project.
PV	Development of a first generation monitoring infrastructure based on fixed wireless technology.
PV	Development of a broad-based training and business development program to assist Energy Service Companies to establish Photovoltaic services.
PV	Development, testing and commercialization of a converter that is tied to solar electric panels that will allow for efficient motor operation and grid interactive qualities.
PV	An AC-link Grid-tied Inverter (GTI) will provide significant advantages over existing inverters 1) higher efficiency, 2) lower initial costs, 3) flexible, rugged operation with trips, 4) superior max power tracking capability. Overall, the AC-link GTI will yield a lower cost of energy for grid-tied solar installations.
PV Thin Film	Commercialization of thin film solar electric panels including improvements in product performance, reduction in product cost, enhanced product certification, and marketing.
Wave/Tidal	Demonstration and commercialization of a Powerbuoy, a wave powered generating technology. The project calls for testing and monitoring the Powerbuoy based on innovative technology that advances the efficiency of converting the mechanical energy from waves into electricity.

The projects have a wide variety of purposes, but apart from the educational projects, all involve the development and/or commercialization of new technologies. The fact that so much of the funds have gone to PV-related projects most likely reflects the fact that there is a dynamic market for PV in New Jersey due to the high uptake of PV through the CORE program. These technologies should enable the PV that is being installed to be used more efficiently and more flexibly.

The second highest level of funding is for hydrogen-related technologies. Hydrogen-related technologies are far less mature than PV, and there is a general lack of infrastructure to support these technologies in the wider market at this time. However, investment in this area will likely prove fruitful, if not now then in the future, especially in the arena of renewable energy storage and retrieval. The certainty on payback for investment in hydrogen technology, however, is less than for other renewable energy technologies that are being implemented on a wider scale.

If all the 2005 projects currently pending approval are funded, then this will provide a boost to the fast-growing thin film PV sector, which potentially could reduce the cost of PV per kWh generated, and advance less-common options for implementing PV, such as building-integrated applications.

One of the most crucial parts of bringing any new technology to the marketplace is the commercialization process. This is an area where business expertise is important. Developing a good technology that works does not mean that it is ready for mass market purchase or installation. It must be certified for safety and it must be designed to integrate with other systems. Few of the projects funded by the program involve commercialization components, yet bringing to market a cost-effective technology ready for wide use could have a significant impact on the renewable energy market in New Jersey.

3.4.7 Recommendations

Presented here are recommendations for the further development of the Renewable Energy Business Venture Financing program that are most likely to help the program to achieve its goals.

1) An annual budget of $7.7 million is recommended for this program for the next funding cycle. This represents a 50% increase over the 2007 budget.
2) Consider actively promoting the technologies that are not yet commercialized and that would make best use of the renewable energy resources that exist within New Jersey’s borders. This would help to spread the funding out more evenly across the different renewable energy market sectors, leading to a healthier overall renewable energy market with the emphasis on solar reduced. These could include: thin film PV, renewable energy storage (both large and small scale), smart grid technologies (to enable renewables to be used to reduce congestion or stress on the grid), wave and tidal, architectural wind (rooftop mounted), and gasification of various waste materials. Note: this is a small sample of potential technologies.
3) Prioritize projects that involve commercialization of technologies for mass market sales and distribution.
4) Fund technologies that can be implemented as utility-scale installations, and the supporting technologies that are needed to tie these into the grid. These are the most cost-effective in the long run when the larger goal of meeting the RPS is considered.
5) Actively market the program to companies that are in the fields most pertinent to attaining the goal of a vibrant renewable energy industry.
6) Complete a thorough evaluation of the projects that have been funded so far and make changes to the program based on this experience. As this program does not directly monitor renewable energy generation, it is important to monitor its progress in other ways (i.e. by

tracking indicators) while the program is running. Otherwise, there is a danger that the projects funded will not be the most productive ones for the New Jersey market.[121]

7) Explore opportunities for leveraging R&D funding opportunities and technology transfer resources already available through the U.S. DOE and other entities. This could involve providing links to the websites of other funding agencies, sponsoring participation of emerging New Jersey businesses at DOE-sponsored events or conferences, as well as potentially providing added incentives for projects that are able secure funding from multiple sources.

3.5 SREC / Behind the Meter REC Trading System

3.5.1 Introduction

A combination of RECs and Alternative Compliance Payments (ACPs) are currently used by suppliers / providers in New Jersey to demonstrate RPS compliance. When the New Jersey RPS first went into effect in 2001, no REC tracking system existed in the region and RPS compliance tracking was completed manually by the BPU. When revisions to the New Jersey RPS went into effect in 2004, requiring suppliers and providers of electricity to meet a minimum solar requirement, New Jersey launched its own certificate trading system to create, verify and track Solar Renewable Energy Certificates (SRECS) and non-solar Renewable Energy Certificates (RECs). The SREC/REC trading system is designed to manage SRECs/RECs from small "behind-the-meter" (BTM) systems which, to date, have not been well-served by any other certificate accounting system. While the system deals with BTM RECs from all New Jersey Class I renewable energy generators, for simplicity, we refer only to "SRECs" for the remainder of the section. Where solar-specific issues are discussed, that distinction is made clear.

This section assesses the structure, implementation and performance of the SREC trading system and provides recommendations for future changes related to functional aspects of the New Jersey SREC market. For a broader discussion of REC trading systems in other jurisdictions, see Section 4 of this report.

3.5.2 Assessment of SREC / BTM REC Trading System Structure and Implementation

SREC Trading System Overview

New Jersey's retail electricity suppliers and providers ("suppliers / providers") are required to use the SREC trading system to demonstrate compliance with their solar RPS requirements.[122] At the time the SREC trading system was launched, there was no other system for tracking the environmental /

[121] A thorough evaluation of funded projects was not completed as part of this assessment due to a lack of available data, and due to the fact that evaluation resources were focused more heavily on the CORE program.

[122] LSEs are referred to as "suppliers / providers" in the New Jersey RPS rules.

renewable energy attributes associated with New Jersey's power supply. In October, 2005, the PJM Generation Attribute Tracking System was launched to track the attributes associated with all electricity transacted in the PJM control area. At that time, New Jersey began using GATS certificates as the primary medium for demonstrating RPS compliance for all renewable energy except behind-the-meter (BTM) systems. However, all RECs from BTM systems funded through New Jersey's CORE program continued to be traded through the SREC trading system, and SRECs transacted through that trading system continued to be required for compliance with the solar component of New Jersey's RPS.

The SREC trading system was established with the goal of providing owners of BTM RECs, and suppliers / providers with solar RPS obligations, with a simple and efficient way to trade SRECs. The primary account-holders in the New Jersey SREC system include: 1) owners of PV and other renewable energy generators looking to sell SRECs associated with their facilities' electricity generation; 2) suppliers and providers of electricity with obligations to obtain SRECs to demonstrate compliance with RPS requirements; and 3) aggregators and brokers.

Issuance of SRECs Based on Estimated / Metered Generation

Generator account holders are automatically issued SRECs into their trading system accounts in an amount equal to the electricity generated from their systems. The SREC program administrator, Clean Power Markets, issues SRECS to generators based on metered system data for generators larger than 10 kW, and based on engineering estimates for systems smaller than 10 kW.[123] Like other REC trading systems, one MWh is equal to one SREC.

A number of factors can compromise the accuracy of engineering estimates for PV system performance, and since a large percentage of New Jersey's PV systems are smaller than 10 kW, it would be beneficial to improve the accuracy of performance data for small systems. A transition to metering of full PV system output is recommended for all systems receiving SRECs for RPS compliance. Smart metering is a priority for the state as part of its Energy Master Plan process, and metering protocols introduced as part of the Master Plan BPU should address the need to meter all PV systems.

SREC Trading System Transactions

Electricity suppliers / providers must retire SRECs within their accounts by the end of the trading period in order to demonstrate compliance with the solar portion of the New Jersey RPS. SRECs can also be retired by other account holders to keep the environmental benefits for their own use, or they can be "reserved" for use in the voluntary green power market or other non-RPS purposes. SREC buyers and sellers identify one another either through the SREC trading system's bulletin board, or with the assistance of a broker and/or aggregator. Through the SREC bulletin board, SREC owners can announce that they have SRECs for sale, and interested buyers then contact them to agree on a sale price. As of May, 2007, 14 brokers and 21 aggregators are registered within the SREC trading system.[124]

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[123] Systems smaller than 10 kW can choose to base their SREC production on actual metered data or engineering estimates. The majority of participants in the SREC program base their SREC production on engineering estimates.

[124] http://www.njcep.com/srec/contact_info.html

The web-based SREC trading system tracks the transfer of SRECs from one account holder to another, as well as the value of SRECs traded through the system. When initiating an SREC transaction, SREC sellers must report the sale price of the SRECs in order for the transaction to be processed. There is currently no system for the SREC buyer to verify the sale price reported by the seller. Actual financial transactions occur through separate contracts that are negotiated outside the SREC trading system.

After an SREC transaction is initiated, the buyer is notified and the SRECs are held in escrow for thirty days. If the SREC seller reports problems with payment within the 30-day period, the SREC transaction can be terminated if necessary.[125] SRECs can be traded at any time during a reporting year, and up until the RPS compliance reporting deadline for suppliers and providers at the end of August.[126]

Administration and Reporting

In addition to designing and maintaining the web-based SREC trading platform, Clean Power Markets provides training and customer service to SREC trading system participants, and provides the BPU with periodic summaries of SREC trading system data, a key piece of which is data on SREC trading values. This summary information is posted publicly, an element which is not present in other major REC trading systems in the country.

Publishing SREC pricing data helps improve the liquidity of the market and can be important for smaller players in the system that may be less savvy about the value of SRECs. However, some brokers and other market actors interviewed as part of the market assessment downplayed the importance of the SREC pricing reports, claiming that the larger players rely more heavily on broker data. In addition, as noted above, the pricing data is currently reported by the seller without being verified by the buyer. This could present the potential for misreporting which could affect market pricing. A simple step that could be taken to limit the potential for misreporting would be for the reported pricing information to be included in the email notifying the SREC buyer that the transaction has been initiated. The administrator could instruct the buyer to report any inaccuracies in the information.

Going forward, it will be worthwhile to ensure that all CORE funded projects are participating in the SREC trading system. Only 45% of PV system owners responding to a survey of CORE program participants reported that they have used the SREC trading system to sell their SRECs.[127] While this reflects the fact that RECs associated with a significant portion of participants' systems (24% of respondents) are owned by the project developer, 6% reported that they did not know who owns the RECs associated with their system. Furthermore, the SREC trading system administrator indicated that follow up to encourage REC program participation would be helpful in the future.

Overall, it appears that Clean Power Markets is performing well in its role as SREC trading system administrator, and that the SREC trading system is functioning smoothly. Thirty CORE program

[125] Personal communication with Jan Pepper, Clean Power Markets, May 15, 2007.

[126] A "reporting year" is defined as June 1 through May 31, and is identified by the year in which the reporting year ends (i.e., the 2005 reporting year was June 1, 2004 through May 31, 2005). The RPS compliance reporting deadline is September 1 of each reporting year.

[127] Sixty-nine respondents answered this question out of a total of 70 survey participants.

developers were interviewed during early 2007 as part of this market assessment. The majority of these developers expressed satisfaction with the use of SRECs in New Jersey and the SREC trading system specifically. Developers explained that SRECs are an important component of the value proposition that helps sell projects and make them economically feasible for both residential and commercial customers. Developers believed that the SREC trading system is functioning well and the average overall level of satisfaction with the trading system, including the certification process, trading system structure, and staff support, was 4.2 on a 5-point scale, with 5 being the highest score. In addition, 74% of CORE program survey respondents ranked their satisfaction with the SREC trading system at a 4 or 5 on a 5-point scale, with 5 being the highest score.[128]

3.5.3 Assessment of SREC Trading System Performance

The following indicators were established by the Summit Blue teamfor tracking SREC trading system activity.

1. Number of SRECs transacted through SREC system (annual and cumulative)
2. Number of participating RE installations (by project size and RE type)
3. Capacity of participating RE systems (MW)
4. Annual RE generation from participating RE systems (by project size and RE type)
5. Number of unique end-use customers/participants (SREC sellers)
6. Distribution of participating facility types (SREC sellers)
7. Distribution of SREC purchasers (% retired by suppliers / providers for RPS compliance)
8. Cumulative weighted average SREC price
9. Awareness of SREC program by potential participants
10. Participant perceptions of SREC value compared to rebate value
11. Number of days to process applications

The indicators, the relationship to the overall the BPU goals, and the results from the indicator analysis are presented below.

Indicator #1: Number of SRECs transacted through the SREC trading system (annual and cumulative)

Indicator #4: Annual RE generation from participating RE systems (by project size and RE type)

[128] Thirty-one respondents answered this question.

Table 3-47 shows the number of SRECs and other behind-the-meter RECs issued (which coincides with Indicator #4) and transacted (which coincides with Indicator #1) for each reporting year in which the SREC program has been in place. SRECs can be traded multiple times before being "retired" on September 1 following the end of the previous reporting year.[129] Therefore, the number of SRECs "traded" exceeds the number "issued" in reporting years 2005 and 2006.

"Retired" SRECs are those that have been taken out of circulation by an SREC account holder either to demonstrate RPS compliance (in the case of LSEs), or to document and maintain title to the environmental attributes of a generator. "Reserved" SRECs are those that were not "retired" by the end of the settlement period for a given reporting year and can be used potentially in the voluntary green power market. Prior to reporting year 2006, SRECs not "retired" by the end of the settlement period were deemed "expired." However, starting in reporting year 2006, these unused SRECs were automatically placed in "reserved" status at the end of the settlement period. The 2007 reporting year is still underway, and the data presented in Table 3-47 reflect activity through March 22, 2007.

[129] The "true up" period for each reporting year extends from June 1 through August 31.

Table 3-47. Volume of SREC Transactions by Reporting Year

SREC Activity	#Solar RECs	#Wind RECs	#Biomass RECs	Total RECs
2005				
Issued	3,409	0	0	3,409
Traded	5,669	0	0	5,669
Retired	3,316	0	0	3,316
Reserved	0	0	0	0
Expired	93	0	0	93
2006				
Issued	12,748	0	13,628	26,376
Traded	19,231	0	0	19,231
Retired	10,889	0	13,628	24,517
Reserved	1,855	0	0	1,855
Expired	0	0	0	0
2007[130]				
Issued	15,440	0	12,645	28,085
Traded	11,676	0	0	11,676
Retired	2	0	0	2
Reserved	0	0	0	0
Expired	0	0	0	0
Total Issued	**31,597**	**0**	**26,273**	**57,870**
Total Retired	**14,207**	**0**	**13,628**	**27,835**

Indicator #2: Number of participating RE installations (by project size and RE type)

Indicator #3: Capacity of participating RE systems (MW)

Indicator #5: Number of unique end-use customers/participants (SREC sellers)

Table 3-48 presents a summary of the number and type of renewable energy generators participating in the SREC program. The number of solar SREC program participants has increased steadily during the nearly three years in which the program has been in place. From September 2005 to September 2006, the number of solar generator participants grew by more than 125%, and the amount of installed capacity represented grew by 150% during that period. While the rate of growth in the number of participants slowed substantially from September 2006 through March, 2007 when the

[130] Data for 2007 is preliminary and does not reflect data for the entire reporting year. Data available through March 22, 2007 are presented here.

program assessment was completed (only 17% growth since September 2006 to present), the installed capacity represented by solar generators in the program grew by 50% during that period. The program Administrator was unable to provide SREC program participant data organized by project size. However, both the rate of growth in the *capacity* represented by SREC participants relative to the growth in the *number* of participants, and reports from brokers, indicate that larger systems are being built and becoming active in the SREC program. This is consistent with CORE program records.

Participation by BTM wind and biomass generators has been much lower than for solar generators, and only one of the registered biomass generators and one of the wind generators has actively participated in the program.

Fifty-nine of the SREC account holders represent more than one solar facility. About half (29) of that group represents two facilities each. The greatest number of facilities represented by any one account holder is 113.

Table 3-48. SREC Participating Renewable Energy Systems by Type

	Solar		Wind		Biomass	
Type	**Number**	**Installed Capacity (DC kW)**	**Number**	**Installed Capacity (DC kW)**	**Number**	**Installed Capacity (DC kW)**
As of September, 2005						
Active	544	6,299	0	0	0	0
Inactive	226	2,627	6	20	5	1,850
Total	770	8,926	6	20	5	1,850
As of September, 2006						
Active	1,424	18,304	0	0	1	2,775
Inactive	312	4,213	6	30	5	8,250
Total	1,736	22,516	6	30	6	11,025
As of March 22, 2007						
Active	1,782	28,486	1	10	1	2,775
Inactive	240	5,379	5	20	5	8,250
Total	2,022	33,865	6	30	6	11,025
Grand Total, Current[131]						
Installed capacity represented by account holders (DC kW)						44,920
Number of renewable energy facilities represented by account holders						2,034

Indicator #6: Distribution of participating facility types (residential, commercial/industrial, institutional)

[131] Current through March 22, 2007.

The SREC program Administrator does not track participating systems by sector. However, as a proxy, one may assume that all systems <10 kW are residential, and there are 1,451 such systems actively participating in the SREC program. Of the 308 actively participating systems that are 10 kW or larger, the SREC program Administrator was able to report that this includes 191 residential facilities, 96 commercial facilities, and 21 public facilities.[132]

Table 3-49. SREC program Participants by Sector

Participant Sector	# Active SREC Participants
Residential	1,642
Commercial / Institutional	96
Public	21
Total	**1,759**

Indicator #7: Distribution of SREC purchasers (% retired by suppliers / providers for RPS compliance)

The SREC program Administrator does not track the types of entities with whom SRECs/RECs are ultimately retired. However, RPS compliance data for the 2006 reporting year confirm that the vast majority of SRECs are retired into the accounts of LSEs (Table 3-50). Based on retail electricity sales during the 2006 reporting year (ending May 31, 2006), the total number of SRECs required to meet the RPS requirement was 10,450. A total of 12,747 SRECs had been issued to solar facilities during the 2006 reporting year, and 10,723 of those were retired at the end of the reporting year. However, not all of the retired SRECs went to LSEs for compliance purposes, as 163 Solar Alternative Compliance Payments were required.

Table 3-50. Reporting Year 2006 Disposition of SRECs

	# SRECs
Issued	12,747
Required for RPS Compliance	10,450
Retired	10,723
Solar Alternative Compliance Payments Required	163
Used for RPS Compliance	10,287
% of Issued SRECs used for RPS Compliance	81%

Indicator #8: Cumulative weighted average SREC price

[132] All educational institutions and municipal facilities are included under the "public" category.

A key feature of the SREC program is the role it plays in improving the transparency of SREC pricing. SREC pricing statistics are posted and regularly updated on the SREC program website.[133] SREC pricing has trended upward over the past three reporting years, though 2007 data presented here only represents the first seven months of the 2007 reporting year (Table 3-51).

Figure 3-13 on the following page presents cumulative weighted average SREC pricing. For Reporting Year 2005, the maximum SREC trading value was $265 and the minimum was $80. For Reporting Year 2006, the maximum SREC trading value was $297 and the minimum was $100. For Reporting Year 2007, as of March, the maximum SREC trading value was $260 and the minimum was $110. The trends in the data presented in

Figure 3-13 shows that SREC trading volume and pricing increases greatly in August which is the end of the true-up period for each Reporting Year.

Table 3-51. SREC Pricing Summary by Reporting Year[134]

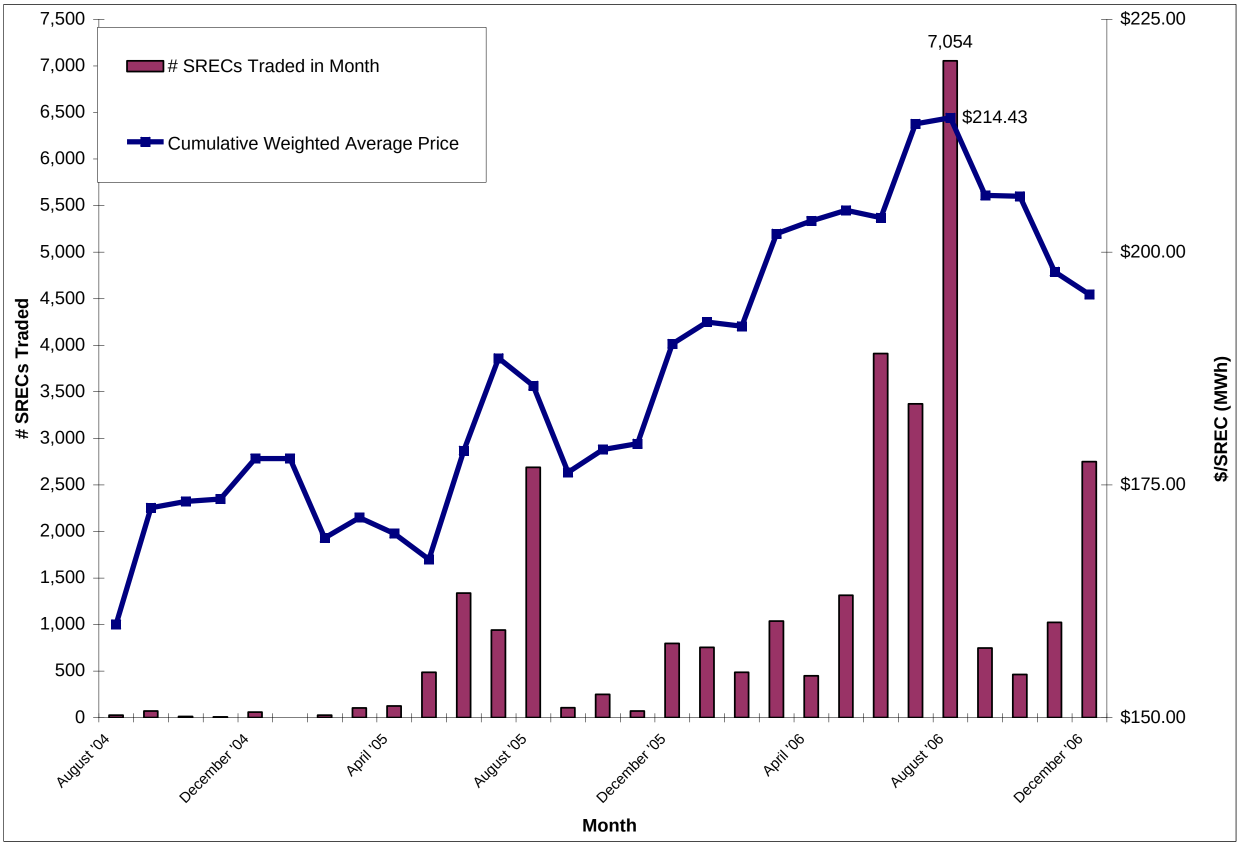
Reporting Year	Average # SRECs Traded (Monthly)	Average Monthly High ($/MWh)	Average Monthly Low ($/MWh)	Cumulative Weighted Average Price[135] ($/MWh)
2005	444	$216	$131	$175
2006	1,381	$251	$141	$194
2007 (through 12/06)	892	$250	$142	$206

[133] Current and historic SREC pricing available at: http://www.njcep.com/srec/trading-statistics.html.

[134] Average values presented here factor in monthly pricing figures for each month of each reporting year up to the end of the settlement period (September 1).

[135] These numbers represent the average of the cumulative weighted average values calculated for each month in each of the reporting years. Cumulative weighted average pricing was calculated by the program Administrator using the following formula: [(number of SRECs sold at price A * price A) + (number of SRECs sold at price B * price B) + ...] / (total number of SRECs sold at price A + total number of SRECs sold at price B + ...)].

Figure 3-13. SREC Pricing and Trading Volume Trends[136]



Indicator #9: Awareness of SREC program by potential participants

Based on CORE program participant survey results, it appears that a large majority of end-use customers participating in the CORE program are aware of the SREC program, but there is still room for improvement in area of SREC program awareness. While 77% of the 70 respondents reported that their systems are registered in the SREC program, 17% reported that they didn't know whether their system was registered.[137] In addition, only 45% of respondents reported that they have actually used the SREC trading system to trade SRECs.[138] This reflects the fact that RECs associated with a significant portion of participants' systems (24% of respondents) are owned by the project developer. However, 6% reported that they did not know who owns the RECs associated with their system.

All CORE program participants receive a letter from the BPU informing them of the revenue opportunities available through participation in the SREC program, as well as information on how to register their systems. However, according to the SREC program Administrator, there has not historically been a great deal of follow up to recruit those who do not respond to the informational mailing about the SREC program; the SREC program Administrator role did not include actively

136 Source: http://www.njcep.com/srec/trading-statistics.html.

137 CORE program participant survey, question B7, n=70.

138 CORE program participant survey, questions B8 (n=70) and B9 (n=69).

reaching out to inactive solar owners.[139] In the future, the Market Manager or SREC program Administrator roles could include taking steps to encourage SREC participation by those who fail to register initially, and those registered system owners who remain inactive in the program.

Indicator #10: Participant perceptions of SREC value compared to rebate value

CORE program participant survey results indicate that the rebate value was significantly more influential in participants' decisions to install a PV system than was SREC value. However, the value of both the rebate and the SREC revenue stream are clearly of great importance to participants. Fifty-six percent of CORE participant survey respondents reported that they would not have installed their renewable energy system if the rebate value were reduced by 25%,[140] and 86% preferred an upfront rebate to other forms of financial incentives.[141] Seventy-four percent of respondents reported that they factored SREC value into their decision to install their renewable energy system.[142] However, it is unclear from the survey data whether respondents' decisions were *dependent* on the prospect of receiving SREC value. Twenty-two percent of respondents stated that they anticipate the value of their SRECs to increase in the future, and nine percent indicated that they believe SREC value will remain approximately the same as it is currently.[143]

Indicator #11: Number of days to process applications

The SREC tracking system is set up to link owner account registrations to solar systems within one to two days. However, the system can only process registrations for renewable energy systems that have been entered into the SREC database. The SREC program Administrator relies on the BPU to provide regular updates of new systems to be added to the database and to forward copies of owner attestations that are required before a system will be activated by the SREC program Administrator. In general, this updating process has proceeded smoothly, with at most a two to three week lag between the time when the associated SREC owner registers for a user account, and the time when system data and attestations are received by the SREC program Administrator from the BPU. However, as of March, 2007, the SREC program Administrator had not received notice of any new system installations since the beginning of 2007.[144] This could be due both to a slow-down in CORE program activity, and the BPU's transition of renewable energy program administration to the market manager.

3.5.4 Recommendations for Future

GATS v. SREC Trading System for Behind-The-Meter Systems

The BPU is exploring whether it would be worthwhile for all renewable energy generators in New Jersey to trade their RECs through GATS as opposed to maintaining a separate state-specific trading platform for BTM RECs. If RECs were traded through GATS, it would not change any RPS

[139] Personal communication with Jan Pepper, Clean Power Markets, March 15, 2007.
[140] CORE program participant survey, question F2c, n=66.
[141] CORE program participant survey, question F3, n=70.
[142] CORE program participant survey, question B10, n=31.
[143] CORE program participant survey, question B10a, n=23.
[144] Personal communication with Jan Pepper, Clean Power Markets, March 15, 2007.

requirements in New Jersey. Suppliers / providers would still be required to provide enough RECs from solar generators to demonstrate compliance with the solar RPS requirements.

It is technically feasible for BTM systems to trade RECs through GATS. If New Jersey solar generators were to transact RECs through GATS, New Jersey would have to certify each generator as RPS-eligible, and the data on their GATS certificates would indicate that they were generated from an RPS-eligible solar facility in New Jersey. Therefore, New Jersey could accurately track the solar RECs for RPS compliance through GATS. GATS does not currently charge any annual fees for generators smaller than 10 MW.[145] However, brokers and aggregators are charged a $1,000 annual fee for participating in GATS. This would be an added cost for any brokers or aggregators currently only operating within the New Jersey SREC trading systems, but should not represent an unreasonable expense for these market participants. New Jersey's SREC buyers and sellers would lose the ability to view SREC pricing data, however, GATS does maintain a bulletin board system in which entities wishing to buy or sell RECs can post their interests.

A benefit of having all systems transact RECs through GATS would be greater simplicity for suppliers and providers fulfilling RPS obligations, and for the BPU's tracking of RPS compliance. Both the BPU and the suppliers and providers must already work with GATS for tracking non-solar RPS compliance, so shifting all REC transactions to one system would streamline the compliance process. Furthermore, phasing out the SREC trading system or shifting the responsibilities of the current SREC program administrator would reduce the SREC program administrator expense, which currently amounts to approximately $550,000 per year.

Another benefit of transitioning all RECs to GATS is that the system is robust and is subject to the scrutiny of participation by many market participants from throughout the large region served by PJM. Therefore, the system should keep pace with the changing needs of the marketplace, and should be more likely to maintain a high level of standardization and accuracy in its tracking functions. Furthermore, to the extent that there is ever an excess of New Jersey SRECs, having solar generators transact SRECs through GATS would facilitate regional trade to other RPS compliance and voluntary markets, improving the fluidity of the market. Similarly, if New Jersey were ever to allow non-New Jersey solar projects to qualify for RPS compliance in New Jersey, regional trade capabilities would be beneficial.

There are currently BTM generator accounts active within GATS and the GATS administrator has noted that the system is capable and that the administrator is willing to support the needs of New Jersey's BTM systems.[146] There is a record of successful participation of BTM generators in the New England Generation Information System (NE-GIS) as well, which is operationally similar to GATS. The assistance of aggregators would be beneficial for small generator owners, but aggregators should be fully capable of working within GATS to provide such assistance.

[145] PJM load serving entities (LSEs) are charged a $2,000 annual fee, and non-LSEs (brokers, traders and renewable energy generators >10MW) are charged an annual fee of $1,000 for use of GATS. LSEs pay an additional fee of $0.008/MWh, calculated based on the LSEs monthly net load served. A fee of $0.25/MWh is charged for certificates transferred into reserve sub-accounts, unless the certificates are used for RPS compliance.

[146] Kerecman, Joseph (PJM Environmental Information System). Personal communication, May 3, 2007.

Primary arguments against transitioning all New Jersey REC trade to GATS include: 1) GATS does not allow the Board to verify that the RECs are created by systems interconnected with a distribution system serving New Jersey or to "confidently rely upon the metered data"[147] 2) current price transparency provided by the SREC trading system would be lost; 3) GATS is not user-friendly for smaller market participants; and 4) it is possible that if the nearly 2,000 relatively small generators currently transacting SRECs through the SREC trading system were to suddenly shift over to GATS, GATS' customer service capabilities would be overwhelmed and fees would have to be charged to small generators. Regarding the first issue, the Board would be responsible for certifying GATS participating systems as New Jersey RPS Class I/SREC eligible, and as part of this process could do its own verification that the system is connected a distribution system serving New Jersey. Also, the Board could maintain the same metering requirements that exist under the SREC / BTM REC trading system and only certify those systems adhering to these rules. For systems under 10 kW, the Board could apply a standard conservative capacity factor (i.e., 12%) to check annualized self-reported solar production used for GATS certificate creation. Eventually, the Board should require all PV systems applying for SREC eligibility to be metered.

It seems that issues 3 and 4 could be addressed if the BPU were to contract with either the market manager or a separate entity, such as Clean Power Markets, to function as a sort of "GATS facilitator," providing customer service to smaller system owners and assisting them in making the transition to GATS. For systems smaller than 10 kW, the GATS facilitator might even play the role of reporting estimated production, since systems of this size currently have no reporting responsibilities under the SREC trading system.

The BPU should monitor the developments in Pennsylvania regarding that state's treatment of BTM RECs since it is dealing with many of the same issues as New Jersey and is pursuing an approach in which BTM RECs would be transacted through GATS with the assistance of an administrator under contract with the state. Clean Power Markets has been hired by the state of Pennsylvania to administer all aspects of their Alternative Energy Portfolio Standard. This will include providing assistance to BTM generators and facilitating REC transaction within GATS from BTM systems, though the details of how RECs from BTM systems will be dealt with have not yet been finalized.

There is not an immediate solution to the fact that SREC price tracking would be lost if all REC trade were to transition to GATS. However, the BPU could easily track SREC trading values through broker reports, and could potentially make these available to the public, or could make it clear to the public how they can access such reports directly from brokers. The BPU may also be able to obtain REC pricing data from suppliers and providers who purchase SRECs for RPS compliance. Among the stakeholders interviewed for the market assessment, there were differing opinions regarding the importance of the SREC trading system's publication of pricing data.

Tiered REC System to Avoid Windfall Profit for Rebate-Funded Systems

Note: The Board requested that the research team comment on the issue of a potential tiered system to avoid windfall profits for rebate-funded systems. However, since the team's analysis of the issue was written, the Board approved (September 12, 2007) a staff proposal to introduce an eight-year SACP schedule which included qualification lifetimes for projects.

[147] This rationale was provided by the Board in its response to comments in the RPS Rules Adoption (N.J.A.C. 14:8-2), April, 2006.

Upon transitioning to a solar incentive structure in which SREC revenues provide the primary financial incentive for PV system owners, SREC prices will need to increase substantially. Owners of past rebate-funded systems would see a windfall profit in the form of SREC revenues that could be as much as three times as high as those they previously received.[148] This potential for windfall profits concerns many.

In general, concerns over windfall profits should be weighed against the need to maintain regulatory certainty and market simplicity. PV systems that received rebates through the end of 2006 only made up approximately 2% of the total amount of capacity that will be needed to meet New Jersey's solar RPS requirement in 2021. It is also important to recognize that windfall profits would be much less of an issue under models which continue to provide solar project owners with enough of a non-SREC financial incentive (i.e., rebate or tariff) that SREC revenues can remain within their current range. However, if New Jersey *does* transition to a model in which projects are heavily dependent on SREC revenues (i.e. the current solar pilot, the underwriter approach, or the auction-set pricing / standard contract approach) mechanisms to minimize windfall profits for earlier rebate-funded systems should be considered.

Potential mechanisms for avoiding windfall profits for rebate funded systems include: 1) introducing a tiered SREC system in which SRECs from rebate-funded systems have a lower value than those from non-rebate funded systems (i.e., count them as Class I resources instead of counting as solar); 2) discontinuing issuance of SRECs to rebate-funded systems; and 3) having the BPU purchase SRECs from rebate-funded systems at a price close to the current average SREC trading value and selling these SRECs to suppliers and providers either at a slight margin to cover administrative costs, or at a market rate.

A tiered SREC system would involve identifying rebate-funded SRECs as such through the data presented on the associated SREC/GATS certificate, and making a declaration, likely in the RPS regulations, about how rebate-funded SRECs will be treated for RPS compliance. A few options for treatment of rebate-funded systems for the purposes of RPS compliance include: 1) count them as Class I RECs; 2) count them as 50% (or some fraction) of a full SREC; or 3) there could be a separate requirement within the RPS solar set-aside that non-rebate funded SRECs make up a certain percentage of the total. It seems that the first two options would be administratively simpler than the third option. And the option of counting RECs from rebate-funded systems as a fraction of the value of a full SREC seems preferable since this would enable the rebate-funded systems to still contribute SRECs toward the state's solar RPS requirement.

Discontinuing issuance of SRECs to rebate-funded systems is not a favorable option because it would change the market conditions that early adopters bought into when they made their solar investment. In a survey of CORE participants, 74% of respondents said they factored in revenue from the sale of SRECs into their decision to invest in their PV system.[149] While many early CORE program participants received substantial rebates and may have already broken even on their investments, it does not seem appropriate to render attributes from rebate-funded PV systems completely void of value for the purposes of New Jersey RPS compliance. Furthermore, since the solar RPS requirement will already be difficult to meet even if SRECs from rebate-funded systems are counted, it would be unwise to restrict potential SRECs from being created for rebate-funded projects. Finally, changing

[148] SACP levels as high as $750 are being proposed by the solar industry for a post-rebate market.

[149] Thirty-one respondents answered this question.

the market conditions could reduce regulatory certainty and cause investors to question the stability of the New Jersey solar market when considering future investments.

A third option for reducing the potential for windfall profits to rebate-funded systems would be for the BPU to only issue SRECs to rebate funded systems if those system owners agree to sell the SRECs to the BPU. The BPU could purchase those SRECs at a price close to the current average SREC market price and then sell those SRECs to electricity suppliers / providers at a small margin to cover administrative costs. This seems to be the option with the lowest level of complexity or disruption to the market.

Multi-Year REC Life

Note: The Board requested that the research team address this issue. For the case of SRECs, the issue was dealt with in a September, 2007 Board decision to extend SREC lifetime to two years.

Currently, RECs used for RPS compliance in New Jersey have a one year lifetime. If the market is not in balance in a given year, scarcity or over-supply of RECs in the market will be reflected in the spot market prices of RECs generated in that year. GATS is set up to allow account holders to establish Clean Energy Portfolio Standard sub-accounts (CEPS) for the purposes of holding unsold or unused eligible RECs beyond the end of the standard certificate trading period for future use toward RPS compliance in accordance with rules set by each state.[150]

Over 80% of developers surveyed as part of the market assessment believed that REC lifetimes should be extended beyond one year to provide renewable energy systems owners with greater flexibility in selling their RECs at favorable prices. This position is consistent with the basic principle that greater flexibility for market actors generally improves market efficiency. Since four other states in the PJM region all have multi-year REC lifetimes, moving to such a system in New Jersey would improve regional compatibility of markets.

Some market actors express concern that a longer lifetime for RECs will make it more difficult to maintain a balance between REC supply and demand in the marketplace, and it will increase the chances that the market will end up in a REC oversupply situation. This would drive down SREC prices and be detrimental for generators.

The increased flexibility associated with shifting to a multi-year REC lifetime would provide some benefits to the market, and developers clearly prefer a longer REC lifetime. Therefore, the BPU should seriously consider pursuing this path. However, New Jersey should also be cognizant of the increased challenges associated with monitoring the balance between REC supply and demand. Depending on the solar incentive structure chosen for the future, the ability to maintain close tabs on the supply and demand of SRECs may be of greater importance.[151]

[150] GATS Operating Rules, May 10, 2006, pg. 33.

[151] As part of the Board Order approved on September 12, 2007, the Board approved an extension of SREC lifetime to two years, subject to rulemaking.

Allowing SREC Creation for Non-Net Metered Solar Systems

New Jersey currently only allows SRECs to be issued "based on electricity generated by a customer-generator on the customer generator's premises," as defined in N.J.A.C. 14:8-2.9 (a), and to solar projects that are "interconnected with an electric distribution system, as defined at N.J.A.C. 14:8-2.2, that supplies New Jersey."[152] This means that for a PV system to be eligible to receive SRECs, it must be net metered and located within the state. This requirement exists for two primary reasons. First, New Jersey is interested in keeping its incentive money and associated economic benefits within the state. Second, New Jersey seeks to maximize distributed generation benefits (matching on-site production with on-site load) associated with PV because the state has serious distribution system congestion problems.

In order to be net metered in New Jersey, a generator must be smaller than 2 MW and its expected production must not exceed the customer's average electric load on an annual basis.[153] The BPU is exploring whether systems which exceed the sizing limits of the net metering rules should be allowed to receive SRECs for solar electricity production.

There are several reasons for New Jersey to want to encourage larger systems. First, they add large amounts of PV capacity relatively quickly and New Jersey is likely to need some larger solar installations to meet its aggressive solar RPS requirements. In addition, the more favorable economics of larger projects can help New Jersey minimize ratepayer impacts— a fundamental guiding principle in the BPU's framework for evaluating new alternatives for the solar marketplace.

When comparing the economics of large commercial projects to those of residential systems, the large systems have a substantial edge over smaller projects because:

1) they receive significantly larger federal tax incentives;
2) there are economies of scale associated with design, procurement and installation for larger systems;[154] and
3) there are low transaction costs associated with these projects since one entity, likely to be sophisticated and knowledgeable of solar market issues, is the main point of communication for the project.

However, despite the more favorable economics of large projects in general, without the financial benefits of SRECs the project *pro formas* of these larger systems are not likely to be compelling enough to encourage investment.

One primary argument against allowing SRECs to be issued to large systems is that this will likely lower the SREC market price. In an incentive system which is totally based on SRECs this could make it difficult for small residential or commercial purchasers to receive enough SREC revenue to make their projects financially viable. Nearly all observers interviewed agreed that the small system market is critical for New Jersey for several reasons, and therefore, that favorable project economics must be maintained for these smaller market participants. First, the solar installers who serve smaller

[152] N.J.A.C. 14:8-2.9(d)

[153] N.J.A.C. 14:4-9.3 (a)

[154] One industry representative noted that systems larger than 1 MW can have upfront costs as much as $1.50/kW lower than the upfront costs for residential-scale systems.

PV customers are large in number and represent a substantial fraction of the job growth that could potentially result from solar market development in New Jersey. Both installers and owners of small PV systems tend to be active in spreading the word about solar and play a key political role in social marketing for PV. In addition, being able to point to a large volume of small PV systems sends a powerful message that New Jersey citizens support the state's substantial investment in solar.

Another potential concern, given the Board's recent adoption of an eight year rolling Solar Alternative Compliance Payment (SACP) schedule with the SACP starting at over $700 / MWh, is that a large solar project could initially command much higher SREC revenues than are needed to make the project economically viable (resulting in windfall profits). However, large systems would likely drive SREC prices down over time.

Another potential argument against allowing very large systems to generate SRECs relates to New Jersey's requirement that SREC-eligible PV systems must be located in-state. If New Jersey were to allow large (non-net metered / utility-scale) PV systems to receive SRECs, it is possible that the favorable economics of such systems would lead entities from other parts of the region to attempt to tap into New Jersey's demand for solar RECs. They could do this by challenging New Jersey's in-state solar requirement on the basis of the Interstate Commerce Clause (ICC) of the U.S. Constitution.

However, other states, including Arizona, California, Iowa, Montana, Nevada and Texas all possess criteria that either prohibit or greatly restrict renewable energy generated out-of-state from counting towards RPS compliance. For any of these states, the potential for ICC challenges exists as it does in New Jersey. It would be unwise for New Jersey to forgo the ratepayer benefits of allowing SRECs for large PV systems in an effort to limit potential ICC challenges which may not materialize. Furthermore, it seems that language could be crafted that highlights the reasons for the in-state requirement (i.e., to limit serious congestion problems and to decrease the state's dependence on imported power)[155] that may limit the risk of potential ICC challenges associated with allowing larger systems to receive SRECs.

The goal to achieve somewhat equitable distribution of SBC funds is another reason to be cognizant of the effects of allowing large systems to receive SRECs for their output. Since small system owners contribute a substantial portion to SBC funds (as electricity consumers) they should have access to the incentives that those funds make possible. If SREC market prices were to decline without a corresponding increase in other financial incentives to maintain favorable economics for small systems, this access could be lost.

Large electricity consumers can also present an equity argument. They are the source of a large percentage of SBC funding and should be given an opportunity to receive benefits from investing in New Jersey's solar market. However, as highlighted above, if SRECs are not issued to large non-net metered systems (i.e., if PV system production is expected to exceed building load, it could not be net-metered), the project economics for those systems may not meet the investment hurdle rates necessary for such projects to be built meaning the full potential for large-scale project development would go untapped..

[155] According to a draft electricity sector summary prepared as part of the New Jersey Energy Master Plan process, 27.7% of New Jersey's electricity was imported from other parts of the PJM territory in 2004.

In summary, New Jersey should allow SREC production from large systems in order to help lower the cost of meeting its solar RPS requirements. In order to minimize the potential negative impacts of making this change, the state should: 1) provide additional financial incentives for smaller systems to account for their higher relative project costs, and the decreased SREC revenues resulting from lower SREC market prices; and 2) consider providing incentives to stimulate development of in-state PV projects rather than *requiring* that all solar be located in-state. This second item for consideration reflects that allowing larger systems to generate SRECs may increase the potential for out of state entities to challenge the constitutionality of New Jersey's requirement that SRECs must, in effect, come from in-state facilities.

3.6 Manufacturing Incentive Program

This section addresses the opportunities and barriers associated with attracting a solar PV manufacturer to create or expand a facility in New Jersey. Funds for a Manufacturing Incentive program were included in the BPU program budgets in 2004 and 2005 but a formal program has not been developed or implemented.

The Summit Blue team conducted telephone interviews with renewable energy equipment manufacturers to obtain input on a range of issues related to the broader market assessment. Questions pertaining specifically to the value of offering a manufacturing incentive program were included in these interviews. Interviews were conducted with four solar, three small wind, and two biomass/biogas equipment manufacturers. The Summit Blue team also obtained information on existing economic development incentives available to businesses locating in New Jersey from an interview with a representative from the New Jersey Economic Development Authority (EDA). In addition, information on manufacturing incentive program offerings in other states was collected through interviews with state incentive program representatives.[156]

This section first discusses the factors considered by PV manufacturers when deciding to locate a new plant, then provides examples of some PV manufacturing facility announcements and associated financial incentives, and discusses how New Jersey's incentives compare to those offered by other states. Relevant conclusions and recommendations are provided at the end of the chapter.

3.6.1 Factors Affecting Location of PV Manufacturing Facilities

Solar manufacturers interviewed for the assignment included those manufacturing both thin film and crystalline PV, inverters and mounting equipment. Table 3-52 below describes some key characteristics of the solar renewable energy manufacturers who were interviewed.

[156] Representatives from other states were mostly focused on direct solar project incentive programs, but provided general information on manufacturing incentives offered by their state.

Table 3-52. Summary of PV Manufacturers Interviewed

Company	Summary
Company 1	Products: Amorphous film for rooftop applications. Recently introduced new technology for residential rooftops. 2006 NJ Sales: 0.1 % of total US revenue Price Forecast: 5-7% gradual drop due to availability of solar grade silicon (worldwide shortage is major cause of cost increases currently being experienced). Other: Committed to R&D. HQ in Montreal, locations in UK, Spain, USA, Ireland & France. Already expanding existing facilities
Company 2	Products: Solar electric inverters for PV systems. 2006 NJ Sales: No more than 10% of total US revenues Price Forecast: Decrease dramatically (50%) due to increased volume & maturity (manufacturing, deployment, finance). Other: Sell directly & through dealer network. 5,000 North American employees. Increasing existing facilities in Mexico (serves Americas and Australia).
Company 3	Products: 50 % PV modules/50% installations. Leading global provider of large scale systems (500 kW->10 MW). 2006 NJ Sales: ~20% of total US revenue Price Forecast: Price will probably drop. New materials substituting for silicon could impact price. Other: Use partnerships. Announced move to new location (March, 2007).
Company 4	Products: Solar PV modules (62-208W), inverters, rack system. 2006 NJ Sales: 15-20% of total US revenue Price Forecast: Price should start to drop off around 2008 as a result of changes in technology. In 10 years the technology will be cheaper & more automated. Other: New plant in TN – would expand to meet growth, sales office in NJ.

Interviews with the solar manufacturers and representatives from incentive programs in other states revealed that several elements must be present in a state to attract a PV manufacturer. Table 3-53 presents a summary of comments from renewable energy equipment manufacturers regarding barriers to and opportunities for locating solar equipment manufacturing facilities.

Table 3-53. Summary of PV Manufacturer Comments

Select Comments Regarding Barriers to and Opportunities for Locating Solar Manufacturing Plant
o Production is highly automated and it costs hundreds of millions of dollars to set up new facility. o Manufacturers value stability of incentives over the long-term. In the past plants have had to close when incentive programs have been discontinued. o PV modules producer sees policy uncertainty o Key factor is domestic market for solar. Other factors include availability of skilled labor at low costs, and location near a transportation corridor. Amorphous thin film production needs a location where goods can be shipped cost effectively as components are provided from various facilities for central distribution. o It takes two years to build a factory, establish sales & marketing etc. Need 1) incentives; 2) predictability, e.g. of policy; and 3) longer term financial incentive programs for renewable energy installations, e.g. 10 years like California not four year budget cycles as in New Jersey. Need policy that looks beyond two years – ten year commitment is necessary to make RE mainstream.
Select Comments Regarding Opportunities for Solar Energy Market Growth
o Many more jobs exist in sales, services, installation than production (like many other trades such as plumbing and general electrical), therefore New Jersey should focus on providing training and incentives to businesses providing installation and other services to the PV industry. o All four interviewees included both CA & NJ as growth markets. States listed as key growth markets by each interviewee are as follows: Company 1) CA, NJ (potentially), smaller NE (RI, CT, MA), NY (most active); Company 2) CA, NJ; Company 3) CA, CO, NV, AR, NJ, NY; and Company 4) CA, NJ, NY, NV, CO. o Pay on basis of kWh of production to change focus from maximizing incentive to increasing product quality. Incentive levels must be adequate. o Integrate solar into new housing using quota/pilot for new housing development. o California Solar Initiative is well designed and cost-competitive. In the longer term NJ should match what's happening in other states and coordinate with federal tax programs. o Regulatory barriers to interconnection have been addressed in NJ – "*as good as it gets in the country.*"

The biggest barrier to launching a new solar manufacturing plant is cost. The scale and investment associated with existing PV manufacturing operations is usually too large to justify relocation; most manufacturers will expand existing facilities rather than build a new plant. As noted by one interviewee, "*We are moving into such large scale production that states can't leverage small facilities to create long term jobs. $4 million won't attract a major manufacturer."* Economic development incentives generally only defray a fraction of the facility development cost and would need to be substantial to make the difference in a manufacturer's decision-making.

Factors that weigh most heavily in manufacturers' decisions to locate a new facility are the size of the local market for PV products, and issues related to the cost of doing business, like cost of real estate, the strength of labor unions, cost of living, cost and availability of trained labor, shipping costs, etc. A long term commitment to solar market development is essential as well. For example, a representative from one PV manufacturing company notes, "*it takes long term commitments to grow the industry. Manufacturers are contemplating major investments because of this...Many installers and distributors… need the long term commitment too."*[157] One interviewee explained that the long-term commitment provided in Pennsylvania gives the industry *"confidence to work with silicon producers to expand capacity. This enables us to secure the feedstock."* Just as it takes some lead time to ramp up solar manufacturing facilities, it takes lead time for silicon suppliers to ramp up their production. Interviewees also emphasized the need for long-term commitments with comments such as "*it takes two years to build a factory, establish marketing, sales and so on*" and the industry needs "*a ten year commitment to make renewable energy mainstream*."

Table 3-54 summarizes key factors in attracting renewable energy manufacturing to New Jersey.

Table 3-54. Key Factors to Attracting a PV Manufacturer

Key Factors	New Jersey Situation
Stable Policies	Policy was not considered stable by interviewees.
Long-Term Commitment to PV Market	Solar set-aside in RPS is long-term, but lack of long-term commitment to financial incentive programs was noted.
Size of Local Market	Second largest PV market in the US.
Cost and Availability of Trained Labor	High wages were noted as a barrier.
Cost of Living	Several respondents noted New Jersey's high cost of living.
Proximity to Components of Supply Chain	Difficult for existing and growing PV industry infrastructure along the east coast to compete with silicon supply and industry infrastructure in California and Pacific Northwest.
Existing PV manufacturing capacity	Limited existing capacity in the state.

3.6.2 Recent PV Manufacturing Facility Announcements and Associated Incentives

Manufacturers do take advantage of state incentives which can be very high. For example, Massachusetts is providing $44 million to Evergreen Solar, which has an existing prototype facility in the state, and will build a new $150 million manufacturing plant for PV modules and solar cells there as well. In Oregon, SolarWorld Ag (formerly Shell Solar) purchased a silicon wafer production facility and plans to invest $400 million in the site to combine high-demand solar cell production with silicon wafer manufacturing. Oregon will provide up to $10 million to support this project. At the same time SolarWorld will double the capacities of its existing specialized solar module facility in California. Pennsylvania made over $100 million available through venture capital, bonds and grants to AE Polysilicon (which produces silicon) to relocate from New Jersey, and has also allowed power companies to enter into long-term contracts which makes it more feasible for renewable energy projects to be financed in the state. Pennsylvania's new Energy Independence Strategy aims to

[157] Jesse Broehl, Editor. *In Wake of California Solar Plan, Industry Prepares for Expansion*, by RenewableEnergyAccess.com January 13, 2006.

accelerate the production of clean energy components and systems by making more than $100 million available in the form of venture capital, loans and grants so Pennsylvania firms can attract private sector investors and grow.

In addition, Kyocera Solar, the world's largest solar module manufacturer, is investing to expand existing facilities (including $33 million for its Mexico location which supplies the Americas and Australia) and BP Solar is spending $70 million to expand its existing Maryland solar panel production facilities.

Table 3-55 highlights some recent announcements of PV manufacturing facility construction and expansion, along with costs and incentives provided to manufacturers.

Table 3-55. PV Manufacturing Facility Construction / Expansion Announcements

Company, Location	Products	Cost of Facility/ Expansion ($m)	Incentives ($m)	Type of Incentives
Evergreen Solar, MA	PV modules & solar cells	$150	$44[158]	Grants, loans, low-cost land lease.
SolarWorld Ag, OR	Solar cells & silicon wafer	$400	$10[159]	Property and business energy tax credits
AE Polysilicon, PA	Polycrystalline silicon	$70	$2-8[160]	Venture capital funds, bonds & grants

3.6.3 New Jersey Incentives Relative to Other States

As noted earlier, the size of a state's PV market plays a significant role in manufacturers' decisions regarding plant location. Given the high costs of PV relative to conventional power sources, the size of a state's market for PV is greatly affected by the availability of financial incentives across a range of market actors, as well as the mandated demand, i.e., RPS requirements, for electricity sourced from PV. Financial incentives are commonly offered in the form of rebates to purchasers of PV systems, but can also take the form of tax incentives, grants, low-interest loans, etc. When deciding to locate a PV manufacturing facility, companies will weigh the availability of a state's overall package of financial incentives for the PV market along with any incentives targeted specifically at attracting a manufacturer.

In New Jersey the primary market drivers for PV installation are the financial incentives offered through the CORE program, as well as the solar set-aside in the RPS. New Jersey's financial incentives for PV installations are strong relative to other states (see Appendix A, summary of key

[158] Includes $23 million in grants to the company and its host community, $17.5 million in low-interest loans from public and private entities, $3 million in savings from a low-cost 30-year lease of state-owned land.

[159] Property and business energy tax (35% of investment up to $3.5 million – likely increasing to 50% up to $10 million) credits.

[160] $1.92 million financial package that includes a $1.76 million loan through the Pennsylvania Industrial Development Authority, a $100,000 grant through the Opportunity Grant program and $65,000 in customized job training funds. The company is eligible to apply for a $5.8 million loan through the Citizens Job Bank program, which offers low-interest loans to companies that create / expand jobs in Pennsylvania.

state incentives for solar), and the state leads the nation in its RPS commitment to PV development. New Jersey is considered the second largest market for solar in the country after California.[161] The New Jersey EDA also offers a number of incentives for businesses to locate in the state including low-interest financing through bonds, loans, and loan guarantees; grants and loans for Brownfields investigation and cleanup; and grants to high-tech businesses creating at least 10 jobs in New Jersey. In addition, New Jersey's Edison Innovation Fund offers a variety of financial incentives to companies focusing on life sciences and technology, and one of its focus areas is the renewable energy industry. In January, 2007 Governor Corzine committed $45 million to the Fund. This supplemented $60 million that was already committed under the Fund in 2006. Through the Fund, companies can gain access to up to $200,000 each for product commercialization, and up to $1 million each for growing existing operations. The renewable energy industry is also one of the areas of focus for venture capital investments made by EDA.[162]

When it comes to attracting PV manufacturers to locate a facility in New Jersey, there is very stiff competition from other states, particularly California where roughly 80 percent of the U.S. solar market has been centered. California's financial incentives include: state personal & property tax incentives; state, utility and local rebates; local grants; state and utility loans and production incentives. California possesses another important element—market demand. The state recently implemented the California Solar Initiative, a historic plan that allots $3.2 billion to fund solar incentive programs in the state for the next decade, providing for installation of about 3,000 MW of solar electric generating capacity. California also has silicon manufacturing facilities to provide raw material for solar PV modules and cells, and proximity to components of the supply chain. Many other states provide attractive incentives for renewable energy manufacturers, making it extremely difficult for New Jersey to outdo competition in its efforts to attract manufacturers.

In interviews with representatives from state clean energy funds, several interviewees cited incentives to attract renewable energy manufacturers to their state over and above standard economic development packages offered. A representative of the Northwest Solar Center (NWSC) explained that Washington State offers enhanced incentives for the use of in-state products as a key means to attract manufacturers to the state.[163] Participants in the state's PV PBI program receive 2.4 times the standard incentive rate of $0.15/kWh if their system uses modules manufactured in-state. However, according to the NWSC, other factors are also major drivers to attracting manufacturers. Some of the lowest electricity rates in the country, as well as a strong existing presence of companies along the solar supply-chain should cause existing companies to expand their capacity in Washington and new companies to enter the state.

Low electricity rates have played a major role in keeping Solar Grade Silicon LLC, a subsidiary of the Renewable Energy Corp, ("REC Silicon") in Washington. REC Silicon and REC Wafer, another REC subsidiary, are the world's largest producers of solar-grade silicon and wafers for use in solar applications. A global shortage of solar-grade silicon, combined with a new tax incentive providing a 40% reduction in state taxes for companies manufacturing solar components in Washington, has led

[161] "Solar Leaders Launch New Group: Americans for Solar Power- PV Manufacturers Alliance" http://www.energyvortex.com, July 23, 2007.

[162] Information on EDA programs obtained from www.njeda.com and http://www.edisoninnovationfund.com/pr_011607.html, "$45 Million Slated to Advance Edison Innovation Fund" January 16, 2007.

[163] Personal communication with Mike Nelson, Northwest Solar Center, February 6, 2007.

the company to triple its supply capacity in the state. The company is also in the process of relocating a solar module production line to Washington. Other solar industry players with an existing presence in Washington include inverter manufacturer, Xantrex Technology Corp, diversified PV component supplier and integrator, Alpha Energy Inc, and PV module manufacturer, Schott North America. When combined with the state tax and installation incentives, the presence of these companies is expected to attract other solar-related companies to the state.[164]

The New York State Energy Research and Development Authority (NYSERDA) offers to defray 25% of potential manufacturers' pre-production costs up to $1 million. Day Star Technologies, Inc., a developer and manufacturer of *CIGS Photovoltaic Foil*™, an alternative to silicon wafer cells, has received two awards under the NYSERDA manufacturing incentive program. This program provides incentives to a range of energy technology manufacturers and is not limited to PV. Other awardees include two companies which produce electric storage technologies, Gaia and Advanced Energy Conversion.[165]

Oregon's major appeal to renewable energy manufacturers is a large state tax credit. The Business Energy Tax Credit that applies to owners of solar equipment applies to solar companies as well. The credit is currently 35% of project costs up to $3.5 million and the state is trying to increase the incentive to 50% of costs up to $10 million. Oregon also offers manufacturing workforce training programs as part of the state's standard economic development incentive.[166]

3.6.4 Findings and Recommendations

Research completed as part of this assessment indicates that a PV Manufacturing Incentive program would not be the best use of New Jersey's clean energy funds. Incentives required would be very high, there is strong competition from other states with existing solar manufacturing capacity and manufacturing incentive programs, and many major manufacturers have recently invested in or are committed to capacity expansions elsewhere. Furthermore, all four of the manufacturers interviewed as part of this assessment said it would be more productive for New Jersey to focus incentive dollars on project-level incentives rather than on the manufacturing sector. New Jersey should focus on establishing stability in its solar market and demonstrating its long-term commitment to building the market, as interviewees indicated that a major barrier to locating a manufacturing facility in the state is the short-term incentive planning cycle.

Strategies that will make New Jersey a more appealing place to locate PV manufacturing facilities and other PV-related businesses include:

- Clearly define and communicate a long-term (i.e., ten year) plan for PV market development in the state.
- Provide support to strengthen the developer infrastructure. All solar manufacturers interviewed cited New Jersey as a growth market but said the biggest opportunities are downstream in sales, services, and local installation.

[164] Personal communication with Mike Nelson, Northwest Solar Center, February 6, 2007.
[165] Personal communication with Jeff Peterson, NYSERDA, February 27, 2007.
[166] Personal communication with Kacia Brockman, Energy Trust of Oregon, March 1, 2007.

- Provide PV manufacturers with information about existing financial resources for businesses locating in New Jersey, such as the Edison Innovation Fund, the Business Venture Assistance Fund, and other economic development resources already available through EDA. Also provide web links from the BPU site to information on the Edison Innovation Fund and other EDA programs not exclusively focused on renewable energy.

- Provide added financial incentives for PV installations using equipment manufactured in New Jersey.

- Expand the market for PV by providing incentives for incorporating PV in new housing developments.

4 RENEWABLE ENERGY MARKET DEVELOPMENT APPROACHES IN OTHER JURISDICTIONS

4.1 Introduction

As New Jersey assesses the performance of its renewable energy programs and considers potential alternatives for the future, it is important to take stock of the strategies being implemented in other jurisdictions. The Summit Blue team spoke with clean energy program and policy implementers in nine states, and reviewed a number of reports and data related to renewable energy policies in the U.S. and Europe. Based on this review, it is clear that it takes a combination of policies, incentive offerings, market conditions and resource availability to make a favorable market for renewable energy development. Given the current renewable energy market structure in the U.S., ideal conditions for maximizing a state's renewable energy potential include having an aggressive but achievable RPS policy, favorable net metering and interconnection policies, tax incentives and other direct financial incentives for renewable energy system owners, a voluntary green power market, and the ability for utilities and power suppliers to enter into long-term contracts with generators.

This section focuses on direct financial incentives available to renewable energy generators, and RPS policies. It provides an overview of the primary types of approaches being pursued in different jurisdictions, and includes discussion of the rationale for pursuing these approaches, as well as the associated challenges. This section first describes the research approach used by the Summit Blue team, then discusses the pros and cons of capacity-based and performance-based incentive (PBI) systems, and provides a summary of PBI programs in place in various jurisdictions. The section then discusses notable features of RPS policies in place in other states, and addresses how REC markets are being used as a means of tracking RPS compliance in many states.

4.2 Research Approach

The Summit Blue team interviewed 12 representatives from renewable energy incentive programs in nine states including California, Delaware, Massachusetts, New York, Oregon, Pennsylvania, Texas, Washington and Wisconsin. These states were selected in an effort to represent: 1) a variety of program types (i.e., performance based incentives in WA and WI, in addition to rebate programs in other states), 2) states with a large-scale commitment to renewables (i.e., CA, MA, NY), and 3) states in close geographic proximity to New Jersey (i.e., DE, NY, PA). Interviewees primarily included solar program directors and those responsible for RPS policy oversight. The interviews included questions about incentive program design and participation levels for PV and other renewable technologies, as well as market-related issues pertaining to REC trade, project finance and non-financial barriers to project development.

Secondary research included reviews of: reports published by the Lawrence Berkeley National Laboratory (LBNL), the Clean Energy States Alliance (CESA), renewable energy organizations such as the American Wind Energy Association (AWEA), American Solar Energy Society (ASES), the American Council on Renewable Energy (ACORE), and other leading renewable energy research groups; state policy summaries provided by the Database of State Incentives for Renewable Energy (DSIRE); state RPS compliance reports; and articles in renewable energy periodicals. Because of New Jersey's significant commitment to solar energy development, and its current focus on transitioning to a market-based solar incentive system, the research focused primarily on solar energy incentive programs.

4.3 Direct Project-Level Financial Incentive Programs

4.3.1 Performance Based v. Capacity Based / Upfront Rebate Incentive Structures

The majority of renewable energy incentive programs use a capacity-based incentive structure in which all, or the majority of the incentive is paid upfront. Representatives from states with these **capacity-based rebate structures** in place provide three primary reasons for supporting the rebate approach.

- Rebates defray high upfront renewable energy system installation costs that have traditionally been a primary barrier to development
- Since rebates are an appealing form of incentive for potential system owners they should move the market faster than other types of incentives
- Rebate programs are easier and less costly to administer than PBI programs.

Results from a survey of 70 participants in New Jersey's CORE program conducted as part of this market assessment provide evidence of the value consumers place on an upfront rebate. Seventy-four percent of survey respondents said they preferred the rebate structure to alternative incentive structures, and 56% of respondents reported that they would not have participated in the program if the rebate amount had been 25% less than the amount they received.[167]

Upfront rebates have also been used to drive PV development in Japan. Japan launched a robust PV rebate program in 1994 through its "70,000 Roofs" program which initially reduced PV upfront costs by 50%.[168] The incentives declined gradually for over a decade until they were finally phased out in 2006. By 2002, 635 MW had already been installed with program incentives. While the Japanese experience was not researched in detailed, there is evidence that the sustained, long-term demand resulting from the Japanese rebate program has led to continued growth in market demand even after the phase out of rebates.[169] In 2006, Japan was the second largest consumer of solar products in the world (second to Germany), and was the leading solar cell producer, with a 35% market share. Four of the top ten manufacturers in the solar industry are Japanese companies: Sharp, Mitsubishi, Kyocera and Sanyo.[170]

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[167] CORE participant survey, questions F6 and F2c.

[168] U.S. Energy Information Administration (2005) "Policies to Promote Non-Hydro Renewable Energy in the United States and Selected Countries."

[169] Boortz, Charles. Testimony to the Finance Subcommittee on Energy, April 12, 2007.

[170] Ibid.

Upfront capacity based incentives are, however, criticized for not providing an incentive to ensure optimal system performance over time. Two studies of California's PV incentive programs in 2005 revealed that systems were not performing as expected. A study of the Emerging Renewables program found that seven percent of systems in a sample of 95 were not achieving expected performance due to shading or soiling, and that three percent of systems in a sample of 140 were either not operational or their performance was well below expected levels.[171]

On the opposite end of the spectrum from purely capacity-based upfront rebates, are programs in which the incentive payment is paid out over time based on actual system performance. Proponents of these **performance based incentive (PBI) programs** point to the following key benefits:

- PBIs provide an incentive to install high quality systems and to maintain systems over time to maximize their performance;
- Due to the time value of money, a guaranteed incentive paid out over time will require less ratepayer funds than an equivalent nominal incentive value paid up-front, in net present value terms.
- The most successful renewable energy incentive programs in the world, European feed-in tariffs, are performance-based.

The potential for PBI programs to reward top-performing systems while avoiding wasting funds on under-performing systems is compelling. However, PBIs have a higher administrative burden than a rebate program in that payments must be made over time.

Reluctant to give up the administrative simplicity of rebates, and recognizing the value to consumers associated with reducing the upfront system cost, some states are opting for program structures which pay participants the majority of their incentive upfront, but also take steps to maximize system performance. A number of program design strategies exist which can help programs address performance-related issues without necessarily introducing a full PBI system (Table 4-1).

[171] Barbose, Galen, Wiser, Ryan, & Bolinger, Mark. (2006) "Supporting Photovoltaics in Market-Rate Residential New Construction: A Summary of programmatic Experience to Date and Lessons Learned."

Table 4-1. Performance-Related PV program Incentive Design Options

Program Design Option	Performance Factors *Potentially* Addressed *				
	Geographical Location	System Design	Equipment Quality	Installation Workmanship	Maintenance
Equipment and installation standards			✓	✓	
Warranty requirements			✓	✓	✓
Installer requirements, assessment, and voluntary training		✓		✓	
Design standards and administrative design review		✓			
Incentive-based approaches					
Performance-based incentive	✓	✓	✓	✓	✓
Expected performance-based buydown	✓	✓			
Incentive hold-backs				✓	
Improved rating conventions		✓	✓	✓	
Post-installation inspections and acceptance testing				✓	
Performance monitoring and assessment					
Performance monitoring by program administrator					✓
Meter display requirements and other information/diagnostic tools					✓
Customer education and training (regarding system monitoring and assessment)					✓
Maintenance requirements and services					✓

* The table identifies what are arguably the *primary* performance factors addressed by each program design strategy; many of these strategies may address additional performance factors as well, depending on their specific design.

Source: Barbose, Wiser & Bolinger, 2006

A 2006 report by the Lawrence Berkeley National Laboratory[172] provides a comprehensive review of the value and implementation status of the design strategies listed in Table 4-1. The report highlights how simple, efficient mechanisms like introducing minimum standards for equipment certifications and ratings, system design and performance, and installer training can deliver many of the benefits of a PBI while maintaining many of the benefits of an upfront incentive. Another straightforward strategy with a substantial impact is a requirement that contractors provide long-term warranties, such as the 10 year warranty requirement on all system components requirement under the California Solar Initiative. One approach that is gaining some momentum is the use of Expected Performance Based Buydown incentive structures in which the incentive amount is determined based on the expected performance of the system, but it is paid upfront. This is the approach being used by the California Solar Initiative (CSI) for systems smaller than 100 kW.

A few of the states interviewed by the Summit Blue team are either already using, or are considering using some of the strategies discussed above to encourage better system performance under their incentive programs. The Energy Trust of Oregon (ETO) recently completed an impact evaluation which showed that the PV systems funded through its rebate program are operating, on average, at 102% of their expected performance level. Given this level of system performance, and the fact that the ETO already takes steps to weed out poor quality systems during the application process, the

[172] Barbose, Galen, Wiser, Ryan, & Bolinger, Mark. (2006) "Supporting Photovoltaics in Market-Rate Residential New Construction: A Summary of programmatic Experience to Date and Lessons Learned."

Trust cannot justify the added administrative burdens and reduced upfront cost assistance associated with a PBI program.[173]

Representatives from solar incentive programs in New York and Wisconsin both mentioned that they are considering, or plan to introduce "expected performance" components to the process of determining rebate values.[174] In Wisconsin, this expected performance-based system will apply to a rebate program funding systems 100 to 400 kW in size. The program will use a 30-day test approach; if the system does not perform as expected within its first thirty days in operation, the program participant will receive a reduced incentive level. Both New York and Wisconsin plan to use of the Clean Power Estimator and Power Clerk tools made available by the company Clean Power Research. These tools enable the program administrators to project system performance based on solar insolation data for specific locations.

Massachusetts has also chosen to use an upfront rebate incentive structure. The state actually abandoned an earlier combined rebate/PBI program format in favor of the more traditional rebate structure. The state initially offered a PV incentive program in which a portion of the incentive was provided upfront, to address upfront cost barriers, and a portion of the incentive was provided over a period of three years based on system performance. The state found that systems installed through the program were performing as expected, and chose to minimize administrative costs by issuing the entire incentive upfront.[175]

Rebate program incentive levels are not discussed in depth here, but a summary of state-level financial incentives for renewable energy project development is included in Appendix A.[176] Rebate levels vary a great deal by state, but when comparing levels from one state to another, it is important to recognize that it is the combination of the rebate, REC revenue, federal tax incentives and net metering that make a renewable energy investment viable. In New Jersey for instance, the PV rebate levels are lower than they are in some other states, but other states do not have the high SREC values that exist in New Jersey due to the demand from the state's RPS solar set-aside and the effect of the $300/MWh Solar Alternative Compliance Payment, which functions as a price ceiling and influences SREC market prices.

4.3.2 Overview of Performance Based Incentive programs

Feed-In Tariffs in Europe

Proponents of the PBI incentive structure often cite the success of European feed-in tariff programs as the rationale for pursuing the PBI approach. Tariffs have been the primary policy mechanism used to drive renewable energy development in Europe, and more than half of the world's wind power capacity and two-fifths of the world's PV capacity has been developed with feed-in tariff

[173] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[174] Peterson, Jeff (New York State Energy Research and Development Authority), personal communication, February 27, 2007. Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[175] Leon, Warren (Massachusetts Technology Collaborative's Renewable Energy Trust), personal communication, November 28, 2006.

[176] The incentives summary table is current as of May, 2007.

incentives.[177] As of early 2007, 18 European nations used feed-in tariffs as the dominant form of support for renewable energy development, and five nations used RPS/quota policies.[178] Tariff programs have been in place in Germany, Denmark and Spain since the early 1990s.

Many thought that increased competition in European electricity markets, coupled with the establishment by the European Parliament of renewable energy development targets for each European Union member nation in 2001, would result in a trend toward increased use of RPS policies in Europe. While several EU nations have established RPS policies in an effort to let market forces bring about the target level of renewable energy development, the majority of EU nations still rely on feed-in tariffs as the primary incentive for supporting renewable energy development.[179]

"Feed-in tariffs" are a form of performance-based incentives (PBIs) in which renewable energy generators are guaranteed a fixed payment for electricity delivered to the electric grid. European feed-in tariff laws require utilities to purchase electricity from all eligible renewable energy generators at fixed rates over a long-term period. For example, feed-in tariff contracts have 20 year lengths in Germany, and in Spain, they last the entire life of the renewable energy generator.[180] Different rates can be set for different technology types and for different system size categories.

Strategies for setting tariff levels vary, but a basic principle of European feed-in tariff programs to provide system owners with a guarantee that they will achieve a sound return on their investment. In Germany, tariff rates are set based on the electricity generation costs for each renewable energy source. Spain's feed-in tariff rate is set as a premium over electricity spot market prices.[181] In the case of Germany, the tariff levels offered to new projects decline gradually on an annual schedule. These tariff schedules are reviewed periodically and adjusted as needed.[182] The cost of European feed-in tariff incentives are borne by all ratepayers in the system in which the tariffs are offered.

Tariffs offer flexibility, as levels can be increased to promote certain types of development. In recent years, feed-in tariff programs have started to offer more tailored support to serve the needs of different types of renewable energy applications, such as enhanced tariff rates for projects that provide added benefits, and/or that need additional assistance to become economically viable. The more recent, tailored feed-in tariffs are sometimes referred to as Advanced Renewable Tariffs (ARTs). Examples of how tariff rates can vary include:

- By ***type of renewable energy facility owner*** (i.e., homeowners, farmers, cooperatives, etc.) as a means of matching the incentive amount to the specific needs of different participant classes;

[177] Gipe, Paul. (2006). "Advanced Renewable Tariffs: Trends and Key Elements." Presented at OSEA Tariffs Conference, September 21, 2006.

[178] Rickerson, W., and Grace R., (2007) "The Debate Over Fixed Price Incentives for Renewable Electricity in Europe and the United States: Fallout and Future Directions." Heinrich Boll Foundation.

[179] Ibid.

[180] Gipe, Paul. (2006). "Advanced Renewable Tariffs: Trends and Key Elements." Presented at OSEA Tariffs Conference, September 21, 2006.

[181] Ragowitz, M., and Huber, Claus. (2005) "Feed In Systems in Germany and Spain and a Comparison." Fraunhofer, Energy Economics Group.

[182] Sijm, J. (2002) "The Performance of Feed-In Tariffs to Promote Renewable Electricity in European Countries." ECN.

- By ***location*** of generator (i.e., to enhance development in grid-constrained areas);
- By ***peak / off-peak generation*** (i.e., Ontario's "standard offer" program provides higher tariff payment for electricity generated during peak periods);
- By ***resource intensity*** available to generator (i.e., France and German wind tariff levels).

Successful application of feed-in tariffs depends on the presence of several key program design elements including a simple, comprehensible, and transparent tariff structure; simplified interconnection; and tariff levels and contract lengths that are sufficient to drive development, and are tailored to the needs of different technology applications. In general, the most fundamental element of success is the ability to provide a project owner with price certainty over a long period of time.

Economic Efficiency and Ratepayer Costs of Feed-In Tariffs

A key criticism of feed-in tariffs is that they are not market based, and therefore, they do not promote competition among generators or respond to changes in the marketplace over time. This argument has been challenged by many who point out that feed-in tariffs do promote competition among renewable energy equipment manufacturers, as reductions in the installed cost of a renewable energy system is an important profit driver for systems installed under feed-in tariff programs.[183]

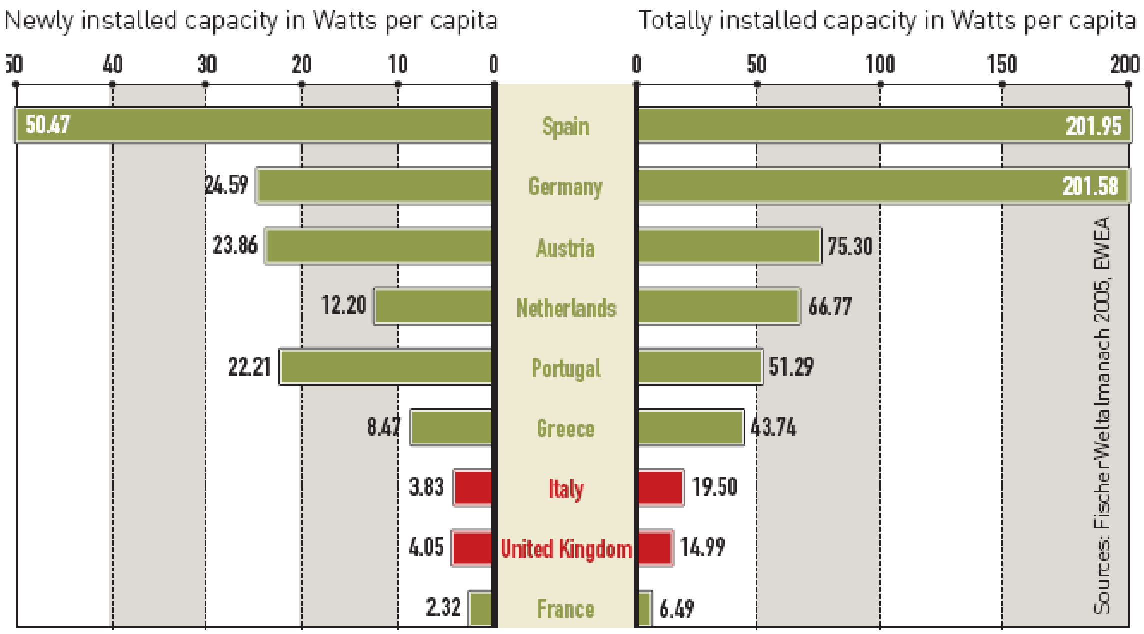
Another criticism of feed-in tariffs is that they are not dynamically efficient since they do not respond to the changing needs of the market. However, as highlighted above, feed-in tariff rates can be reduced over time to reflect expected reductions in renewable energy generation costs, and these schedules can be reviewed periodically. Furthermore, feed-in tariff rates can be set based on a market index, as in Spain, where they are set as a premium over spot market prices. Therefore, feed-in tariffs are not immune to changing market conditions. It should also be noted that the challenge of setting the right incentive level is not unique to feed-in tariffs. Upfront capacity-based incentives must also be set based on policy-makers' best estimates of what is necessary to drive an appropriate level of market activity.

While policy-makers will never track the needs of the market as well as a purely market-based system, the risks and uncertainty of the market carry their own costs. These costs can result in greater overall ratepayer impacts than those associated with potentially miscalculating the ideal feed-in tariff level. In the past two years, three European studies comparing the economic efficiency of feed-in tariffs to those of RPS policies have found that feed-in tariffs result in lower overall costs due to the fact that such programs avoid investment uncertainty and the associated risk premiums. These studies include a 2005 study by the Commission of European Communities, a 2005 study by the German government, and a 2006 study by the United Kingdom Treasury's Stern review on the economics of climate change.[184] Figure 4-1 and Figure 4-2 show that European feed-in tariffs have been more effective than RPS policies thus far both in terms of developing renewable energy capacity and in terms of levelized cost of generation.

[183] Rickerson, W., and Grace R., (2007) "The Debate Over Fixed Price Incentives for Renewable Electricity in Europe and the United States: Fallout and Future Directions." Heinrich Boll Foundation.

[184] Ibid.

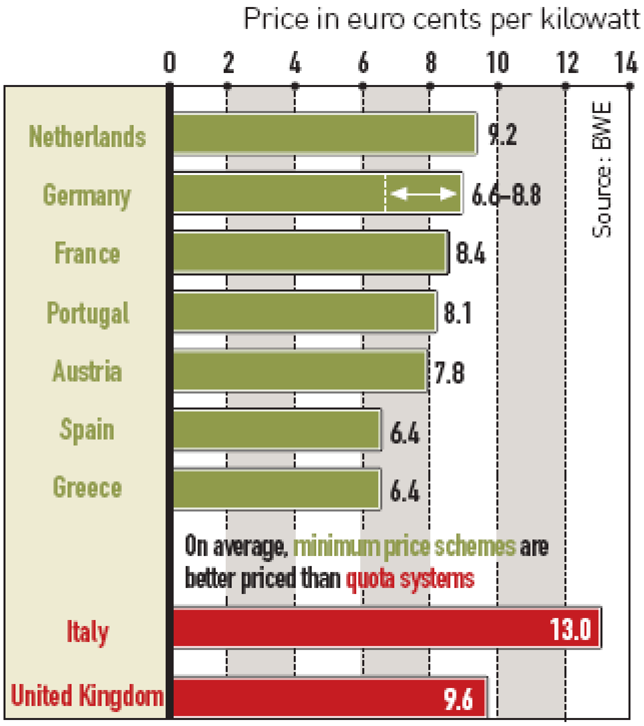
Figure 4-1. 2004 Installed renewable energy capacity additions in nations with feed-in tariffs v. RPS (quota systems)[185]



Source: Grotz and Fouquet, 2005

[185] For comparison, in 2003, New Jersey installed 0.13 W_{DC}/capita of renewable energy (solar, wind, biomass and fuel cells), and in 2006, New Jersey installed 3.2 W_{DC}/capita of renewables. The authors of the paper did not specify which renewable resources were included in the values shown in the tables shown here, or whether the tables referenced AC or DC watts.

Figure 4-2. Prices for Wind-Generated Electricity per kw in 2003 in Nations with Feed-In Tariffs V. RPS (Quota Systems)



Source: Grotz and Fouquet, 2005

Differences Between European Feed-In Tariffs and U.S. PBIs

While some US jurisdictions (i.e., California, Washington, Minnesota, Wisconsin) have started offering PBIs which share similarities with Europe's feed-in tariff programs, some key differences exist:

Level of Incentive: In the U.S., incentive levels are typically set with the goal of reducing the investment burden on renewable energy system owners, but not necessarily to the point at which the investments would be considered attractive to mainstream investors. In contrast, European feed-in tariff levels are designed to make renewable energy investment an attractive business opportunity.[186]

Incentive Period: In most U.S. PBI programs, the incentive period is much shorter than in Europe (i.e., five years for the CSI as opposed to 20 years for the German feed-in tariff).

Technology Types Receiving Incentives: Most U.S. PBI programs offer incentives to a very limited number of resource types, whereas most European programs provide incentives to a whole range of renewable technologies.

[186] Gipe, Paul. (2006). "Advanced Renewable Tariffs: Trends and Key Elements." Presented at OSEA Tariffs Conference, September 21, 2006.

Simplicity of Incentive Structure: In most European nations, the feed-in tariff is the only incentive received by a generator. Therefore, the incentive is very simple to explain to potential system owners. In contrast, in the U.S. PBIs are added on to a range of other types of financial benefits including net-metering, tax incentives, and REC sales. This can make the value proposition much more complicated to explain to potential renewable energy system owners.

Regional / National v. State-Level Policy: One reason European incentive programs can be so much more streamlined is that renewable energy policy has been dealt with at the national level in Europe, and the European Union is moving toward a harmonized renewable energy policy structure. In the U.S., states have taken the lead on renewable energy policy, while limited incentives have been offered in short-term increments at the federal level. This has made it difficult to offer streamlined, sustained incentives in the U.S. and has hindered the investment community's ability to plan for renewable energy development.

Performance Based Incentive Programs in the U.S.

Utility or state-level PBI programs are currently available in 22 states.[187] For purposes of this report, we have counted only official PBI programs, or structured REC purchasing programs offered by utilities and/or state agencies. We have not counted states that use RECs as the mechanism for RPS compliance but offer no official REC purchasing program, though RPS-based utility REC demand, and associated REC production by renewable energy systems in New Jersey and Nevada was listed as a PBI on the DSIRE website. While the state of Washington's PBI incentive is not counted here as a ratepayer funded program, its cost impacts are similarly distributed across because it is funded by taxpayers, as discussed in the summary of Washington's PBI program. This information was current as of April 2007.

Many of these PBIs are utility-based REC purchasing programs funded with revenues from voluntary green pricing programs. Seven of the 22 states (California, Massachusetts, Minnesota, New Mexico, New York, Ohio and Washington) offer PBI programs funded either by ratepayers or taxpayers. In addition, several states with RPS policies use RECs as the medium for obligated entities to demonstrate RPS compliance. In these states, revenues from the sale of RECs are a form of PBI for renewable energy system owners. However, this section focuses only on structured PBI programs. REC markets and their role in RPS compliance are addressed in a later section.

[187] Data collected from DSIRE website: www.dsireusa.org..

Table 4-2. Summary of Utility and State-Level PBI Programs[188]

States	Voluntary GP program / Ratepayer Funded	Comments
Alaska	Funded by Voluntary Green Power Market	Offered by Golden Valley Electric Association. Depending on amount of participation in voluntary green power program, participating wind, solar, and biomass systems receive an incentive up to $1.50/kWh. Systems up to 25 kW can participate.
Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee, Virginia	Funded by Voluntary Green Power Market	Tennessee Valley Authority provides PBI ($0.15/kWh res/small commercial, $0.20/kWh commercial) for PV and wind systems sized up to 50 kW.
Massachusetts	Ratepayer Funded	Massachusetts Green Power Partnership provides a variety of REC purchase arrangements (REC purchase contracts, put / call options for REC purchase). program limited to utility scale RPS-eligible renewable energy projects selected through periodic competitive solicitations.
Minnesota	Funded by Voluntary Green Power Market	Three utilities offer a PBI incentive for PV systems. Depending on amount of participation in voluntary green power program, participating PV systems receive an incentive up to $1.00/kWh. Systems up to 40 kW can participate.
Minnesota	Ratepayer Funded	State-wide SBC-funded program launched in 1999, wind, biomass, hydro and anaerobic digestion plants were offered $0.01-$0.015/kWh over a ten year period. program stopped accepting new participants in 2005.
New Mexico	Ratepayer Funded	PNM buys PV system RECs at a rate of $0.13/kWh through 2018. Payments made monthly. RECs are used for RPS compliance.
New York	Ratepayer Funded	To procure resources to meet the state's "main tier" RPS requirements, the New York State Energy Research and Development Authority (NYSERDA) conducts periodic solicitations and enters into long-term REC purchase contracts with qualifying utility-scale generators.
North Carolina Green Power	Funded by Voluntary Green Power Market	Through this statewide green power program, in which the state's three investor-owned utilities and several municipal utilities participate, solar, wind, biomass and small hydro projects receive payments of $0.22/kWh for both electricity and RECs for a 5-year period.[189] Payment of incentives depends on green power program success.
Ohio	Ratepayer Funded	Commercial wind projects built before 12/31/08 will receive

[188] Data current as of April 2007.

[189] Net metered systems cannot participate in the program, but participating systems receive payment both for green attributes / RECs and for electricity through a Power Purchase Agreement with their utility.

States	Voluntary GP program / Ratepayer Funded	Comments
		$0.01/kWh (or $0.015/kWh if turbine manufactured in Ohio). Participants enter program through solicitation which is accepting applications through 7/16/07.
Vermont	Funded by Voluntary Green Power Market	Central Vermont Public Service pays owners of anaerobic digesters 95% of the Locational Marginal Price published by ISO-NE, plus $0.04/kWh. program supported with revenues from CVPS' "Cow Power" green pricing program.
Wisconsin	Funded by Voluntary Green Power Market	We Energies pays solar participants 22.5 cents per kWh (for systems up to 100 kW) and biogas participants 8 cents per kWh for on-peak production and 4.9 cents per kWh for off-peak production. Participants receive payments over a period ten years. The solar program will accept new participants until a total of 500 kW of solar capacity is funded. New applicants are expected to enroll through 2008.

PBI program structures vary significantly across states and some program structures do a much better job than others at addressing the needs of potential renewable energy project owners. For example, a program in which the PBI incentive level varies depending on the level of participation in a green power program will be less valuable to a solar owner than one that provides a guaranteed level of support because the financial community will look at the certainty of the project's revenue streams when deciding whether or not to provide financing. Other factors affecting the value of the PBI include the incentive amount, and whether the incentive is offered in addition to other benefits, such as net-metering. In most states, the PBI is offered in addition to the net metering benefit, though some states, like Wisconsin, do not allow participating systems to take advantage of net metering in addition to the PBI, or the state/utility does not have a net metering policy.

Following are summaries of key program features of three ratepayer/taxpayer-funded PBI programs. These programs have been highlighted because of their unique program structure or their relevance to New Jersey.

California Solar Initiative

In January, 2007, California's existing solar incentive programs were replaced with the California Solar Initiative (CSI), a statewide incentive program managed by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), and administered by the state's investor owned utilities.[190] Many details of the CSI were stipulated in Senate Bill 1, the program's enabling legislation that was signed by Governor Schwarzenegger in August, 2006. With a goal of installing 3,000 MW of solar electric capacity by 2017, the CSI has the highest solar installed capacity target of any state solar initiative in the U.S. The CSI is a 10-year (2007-2017) program that provides the industry with predictable, declining incentives that are intended to facilitate sustained

190 The CEC manages only the New Solar Homes Partnership component of the CSI. Further information on the CSI is available at http://www.gosolarcalifornia.ca.gov/, and the CSI program handbook is available at http://www.gosolarcalifornia.ca.gov/documents/index.html. Information discussed in this report was obtained from CPUC Decision 06-12-033, December 14, 2006, and from http://www.gosolarcalifornia.ca.gov/.

orderly solar market development. Incentive amounts will decline gradually over the next ten years at a rate of approximately seven percent per year.

The CSI gets around some of the administrative burdens of monitoring and issuing PBI payments over time by providing a one-time upfront incentive payment option for systems smaller than 100 kW. Qualifying systems can receive an upfront lump-sum incentive called an "Estimated Performance Based Buydown" (EPBB). The EPBB amount is calculated based on the expected future performance of the system, taking into consideration performance factors such as location, orientation and shading.

All program participants with systems larger than 100 kW must participate under the Performance-Based Incentive (PBI) structure. Incentive payments are issued to participants on a monthly basis over five years, remaining at a constant $/kWh rate for program participants entering under each program incentive level "step." The five-year period was selected because it is considered to be the minimum amount of time that allows for natural variations in annual weather conditions to level out, thus reducing financial risk associated with the PBI structure. Decision-makers believed that a longer-term incentive payment period would unnecessarily increase administrative costs (metering/monitoring, incentive payments and record-keeping). Systems smaller than 100 kW can opt to receive their incentive through the PBI structure rather than receiving an up-front EPBB.

Residential, commercial, and government / non-profit entities each qualify for a different incentive level. For the EPBB approach, the incentives start in 2007 at $2.50/W for residential and commercial entities, and $3.25/W for government / non-profit entities. For the PBI structure, the incentives start at $0.39/kWh for residential and commercial entities and $0.50 for government / non-profit entities. The incentive amounts decline along an installed capacity-based schedule of incentive "steps."

Some additional important features and developments related to the CSI include the following:

- An additional goal of the CSI is to place solar energy systems on 50% of new homes in 13 years. The New Solar Homes Partnership (NSHP) is a subset of the CSI in which incentives are offered to encourage solar installation on energy efficient new homes.

- The total program budget over 10 years is $3.3 billion. Of this, $400 million is allocated to the California Energy Commission (CEC) to fund solar on new homes in Investor Owned Utility (IOU) territories, $2.167 billion is allocated to the California Public Utilities Commission (CPUC) to fund solar projects in IOU areas for all project types except new homes, and $784 million is allocated to fund projects in Publicly Owned Utility territories.[191] Ten percent of the total CPUC budget is set aside for administrative costs.[192]

- Although solar projects may be sized up to 5 MW, an individual project can only receive incentives for the first MW of installed capacity.

- As of January 1, 2008, all systems >50 kW must use PBI structure (as opposed to EPBB). As of January 1, 2010, all systems >30 kW must use PBI structure (as opposed to EPBB).

[191] Clinton, Jeanne, "California PUC's California Solar Initiative program." Presented at Clean Energy States Alliance Fall Meeting, December 4, 2006.

[192] CPUC Decision 06-12-033, December 14, 2006.

- All participating facilities must undergo an energy audit. Audits are waived for buildings with LEED or Energy Star certification.

- Senate Bill 1 stipulated that all ratepayers with a solar system subscribe to time-variant pricing. According to an Administrative Law Judge (ALJ) ruling, at the beginning of the program, all new participants must take advantage of any existing TOU rate already offered by their utility (past incentive recipients are not required to subscribe to TOU rates). Going forward, CPUC will develop a solar-specific TOU tariff.

After its first three months of implementation, the CSI had seen a great deal of activity at the large commercial level, but limited activity by systems smaller than 100 kW. [193] Applications by large commercial projects (applying under the PBI component of the program) were far exceeding expectations, with most activity in PG&E territory. Developers were rushing to get these large project applications in under the higher incentive level "steps." With 80 MW worth of applications, the program was already into its 3rd step by the end of March and was expected to be in the 4th step shortly thereafter. There was some concern that the applications were too rushed and that many of the applicants in the pipeline either are not fully committed, or will not be able to complete their installation in the one-year timeframe necessary once their application is approved.

Applications by smaller systems (<100 kW) under the EPBB were falling far short of expectations. During the first three months of 2007, the stream of applications for residential systems was nearly 80% lower than the level of applications received during the same period last year.[194] This low level of small system participation was thought to be due to the fact that smaller systems were required to be on a time-of-use rate if one was offered by their utility. Systems are typically sized based on a customer's average monthly usage and available roof space, and in many cases they do not provide enough electricity to meet a household's peak electricity usage during peak pricing periods. If a PV system does not generate enough electricity to offset a customer's full load at peak times, the customer will pay high peak rates- hurting the system payback. This was a major problem in SCE territory where a TOU rate is in effect. There was a major push by the industry to get rid of the TOU rate mandate, and this movement was successful. Since systems smaller than 100 kW can choose either the EPBB or the PBI incentive payment structure, in many cases, installers are encouraging projects 20-99 kW to go with EPBB because payback is expected to be better.

Massachusetts Green Power Partnership

The Massachusetts' Green Power Partnership (MGPP) is administered by the Massachusetts Technology Collaborative's Renewable Energy Trust (MTC). Under the MGPP, MTC functions as a REC buyer under a variety of different arrangements, determined on a project by project basis. MTC enters into 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 options. The program has had two solicitations (2003 and 2005), and 11 projects have been funded representing $59M in nominal funding commitment.[195]

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[193] Renewable Energy Access Podcast, "Special Report: California Solar Initiative Update." March 30, 2007.

[194] Lifsher, Marc. "Rebate rule chills sales of solar Installers fear collapse as many homeowners choose to avoid associated higher utility costs." Los Angeles Times. May 8, 2007.

[195] Bolgen, Nils (Mass Technology Collaborative), personal communication, April 10, 2007. Information regarding MGPP also came from MTC's website: http://www.mtpc.org/renewableenergy/mgpp.htm.

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 (or MTC would commit to a future set of years selected by participants). The second round of program funding was sourced about 50% from SBC funds and 50% from Alternative Compliance Payment (ACP) funds. Approximately $19 million in ACP funds 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 treasury bonds and then 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 low in comparison to the proxy costs assumed for a New Jersey underwriter program for purposes of modeling the ratepayer impacts of alternative solar market transition scenarios. The MGPP program model could likely be scaled up to support a larger number of projects, but MTC has not expressed any intent to use the program as a universal solution to renewable energy generators' challenges of securing long-term contracts. If a similar program model were adopted in New Jersey, steps could be taken to standardize an applicant review process and contract terms. Furthermore, the program could be adapted to focus solely on a particular technology or size range. A narrower program focus, coupled with a sufficient budget, could enable the program to support a much larger volume of projects.

Washington

The state of Washington's PBI program started in 2005 and is administered by the Northwest Solar Center. The program's design reflects the state's interest in minimizing ratepayer impacts and establishing a model for a larger-scale future program. A performance-based program design was selected to emulate the successful German tariff system which is based on the goals of making renewables an attractive investment opportunity and ensuring that program funds are not wasted on poor-quality installations.

The program provides incentives to a wide range of renewable technologies. The base incentive level is 15 cents per kWh, but the level is increased for systems with equipment manufactured in Washington. The maximum incentive level is 36 cents per kWh for projects with solar modules manufactured in the state. The maximum incentive payment a participant can receive in one year is $2,000.

The Washington program is unique in that the incentive payments are made by utilities who in turn qualify for a state tax credit equal to the amount of the incentive payments. Therefore, the cost of the program is distributed across all taxpayers in each utility territory, having a similar effect as a ratepayer-funded (SBC fund) program. In addition, program participants can receive payments until the program expires in 2014 which provides an incentive for early installations.[196]

4.3.3 Rationale for Incentive Levels

As noted earlier, in Europe, feed-in tariff levels are set with the goal of providing system owners with a guaranteed reasonable return on their investment. Rationale for the choice of incentive levels in the U.S. varies across states. In Oregon, the ETO incentives are based on the goal of funding only the "above market costs" of a project (i.e., those costs that will not be recovered within a reasonable timeframe from offsetting retail electricity purchases, and the sale of RECs).[197] For commercial projects, ETO sought to provide investors with a 10 to 13% return on investment, which ETO believed to be consistent with the investment hurdle rate corporations typically use to evaluate investment opportunities. According to ETO, providing any greater return than this would be an inappropriate use of ratepayer funds. For residential participants, ETO focused on determining the level of investment value that would move the market. Seeking to maintain a consistent overall investment value for participants, both the commercial and residential incentive levels for ETO's programs have changed in response to changes in federal incentive offerings. In the case of the residential incentives, the reduced ETO level slowed down program activity enough that ETO chose to adjust it upward again.

Other programs, such as those in New York, Wisconsin and Delaware, have used approaches similar to those used by ETO for setting incentive levels. In general, program designers have sought to set their incentive levels high enough to trigger market activity without overwhelming the base of qualified installers or depleting program budgets too quickly. In the case of Delaware, the solar rebate was set at 50 percent of project costs because it was determined that this simple round number would compel more potential PV system owners to act than the original 35 percent figure that was envisioned for the program.[198] In New York, NYSERDA has also sought to establish an incentive level that would offset roughly 40 to 50 percent of total installed costs after taking into account the other incentives available such as the NYSERDA loan fund and tax credit opportunities.[199] Like ETO, program managers in many states have adjusted incentive levels a number of times in response to changing market conditions in an effort to maintain the same overall level of financial assistance.

California and Washington have taken the approach of setting a clear schedule of incentive levels and letting the market respond. In the case of the CSI, the incentive levels are scheduled to gradually drop as certain installation thresholds are met until finally the incentives are phased out all together in

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[196] Nelson, Mike (Northwest Solar Center), personal communication, January 6, 2007.

[197] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007. The main form of financial incentive in Oregon is a state tax credit. For non-taxable entities, the state offers an official "pass-through" in which companies with a tax burden take the tax benefit of non-taxable projects in exchange for a lump-sum payment to the non-taxable entity.

[198] Lynch, Scott (State of Delaware Energy Office), personal communication, January 5, 2007.

[199] Peterson, Jeff (New York State Energy Research and Development Authority), personal communication, February 27, 2007.

2017. The program has devised specific criteria under which the incentive levels would be adjusted in response to changing market conditions.

The Washington PBI program incentive level was designed to provide projects in the 3.5 kW size range a 10 year simple payback on their investment, and to provide program participants with levelized costs that would be competitive with conventional energy costs. Incentive levels under this program are intended to remain the same for the duration of the 10 year program.[200]

4.3.4 Project Finance Mechanisms

Interviewees commented that the majority of solar projects are self-financed. Most projects were paid for with cash on hand or through home equity or standard bank loans. In Oregon, roughly half of PV incentive program participants reportedly took advantage of a low-interest loan program made available to finance energy efficiency and renewable energy projects.[201] In New York, a small percentage of PV program participants have taken advantage of NYSERDA's low-interest loan program, while members of the wind industry have reported that the loan program is an important resource for potential on-site wind projects.[202]

Some Washington utilities are reportedly starting to fund solar projects, taking advantage of their access to low-cost capital.[203] In Delaware, some installers are starting to offer their own project finance options.[204] ETO reports that third party financing is starting to emerge in Oregon and the organization expects that third party financing will play a significant role in improving the ability of public projects to take advantage of tax incentives.[205]

4.3.5 Levels of Participation

California is the national leader in PV installed capacity. The combined PV installed capacity resulting from a variety of incentive programs in place in California dating back to 1981 is 198 MW.[206] For comparison, as of the end of 2006, a total of 27 MW of PV had been installed in New Jersey with funding from the CORE program.

While states with the highest incentive levels tend to also have high levels of program participation, this is not always the case. In Wisconsin, where PV investors can take advantage of We Energies' PBI program offer of $0.22/kWh in addition to a state rebate covering 25% of the system's upfront

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[200] Nelson, Mike (Northwest Solar Center), personal communication, January 6, 2007.

[201] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[202] Peterson, Jeff (New York State Energy Research and Development Authority), personal communication, February 27, 2007.

[203] Nelson, Mike (Northwest Solar Center), personal communication, January 6, 2007.

[204] Lynch, Scott (State of Delaware Energy Office), personal communication, January 5, 2007.

[205] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[206] Data on total installed capacity in the state is from http://www.energy.ca.gov/renewables/emerging_renewables/GRID-CONNECTED_PV.PDF . A great deal of this capacity resulted from Sacramento Municipal Utility District programs. Combined program records for the Self Generation Incentive program and the California Solar Initiative show that 79 MW of PV capacity has been installed under those programs since 2001.

cost, the PBI program has funded only 291 kW of installed capacity since it was launched in October, 2005. However, this participation level is in line with the utility's goals for the experimental program. Participation in the biogas PBI program has been much lower. It should be noted that the value of the incentives are defrayed by the fact that We Energies' program participants cannot also take advantage of net metering benefits.[207]

In New York, NYSERDA's PV rebate program has yielded 2.9 MW of installed capacity from 2003 through 2006. The small wind program has yielded 164 kW of installed capacity in the same timeframe. NYSERDA attributes this comparatively low participation rate for wind projects to the permitting challenges associated with siting small wind systems.[208]

As of March, 2007, the ETO had seen 1.9 MW installed through its PV rebate program since it started in 2003. ETO representatives have found that participation is fairly sensitive to changes in the incentive level.[209]

The Washington PBI program only started in August of 2006 and had 250 PV systems, one anaerobic digester and six small wind systems approved for participation as of January, 2007. The Northwest Solar Center expects that participation will increase once an in-state PV module manufacturer is up and running and program participants can start taking advantage of the 36 cent per kWh incentive level available to systems with Washington-made modules.[210]

The Delaware programs' levels of participation have been low as well. No wind systems have been installed, and as of January, 2007 only 80 PV systems had been installed since the program went into effect in 1999. Delaware has seen the highest level of participation by those installing ground source heat pumps.[211]

4.4 Renewables Portfolio Standard (RPS) Policies

4.4.1 Overview of Purpose and Range of RPS Structures

In general, RPS policies are seen as a means of mandating demand for renewable energy development while using market forces to ensure that the most cost-effective technologies are deployed first, thus minimizing ratepayer impacts. However, like New Jersey, other states have included special technology-specific provisions within their RPS rules to increase demand for solar and other technologies which may have low cost-effectiveness, but that provide other key benefits.

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[207] Siegrist, Carl (We Energies), personal communication, March 1, 2007.

[208] Peterson, Jeff (New York State Energy Research and Development Authority), personal communication, February 27, 2007.

[209] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[210] Nelson, Mike (Northwest Solar Center), personal communication, February 6, 2007.

[211] Lynch, Scott (State of Delaware Energy Office), personal communication, January 5, 2007.

Arizona, Connecticut, Maine, Massachusetts, Minnesota, New Jersey and Texas were among the first states to pass RPS policies in the late 1990's. Electric industry restructuring was underway in many states during this time period and several states, including New Jersey, first introduced RPS requirements as part of their electric industry restructuring legislation. In the PJM territory, the other jurisdictions with RPS policies include Delaware, the District of Columbia, Maryland and Pennsylvania. Maryland's first compliance year was 2006, but the remaining jurisdictions are still in their first compliance year.

Most states base RPS requirements on percentages of retail sales to customers in the state. The initial RPS targets in most states were relatively conservative, with ultimate percentage requirements (i.e., the year with the highest level of mandated demand) rarely exceeding 10%. Within the last few years, several states have introduced more aggressive RPS policies that have included ultimate targets as high as 30% by 2020.[212]

It is important to recognize that the details of an RPS are more important in determining the policy's overall impact than its percentage targets. Details regarding the geographic, vintage, and technology requirements of an RPS, as well as the policy's enforcement mechanisms are most significant. A few examples illustrate the impact of RPS design details, and why it is difficult to make "apples to apples" comparisons across states.

Geographic Eligibility

Colorado's RPS was recently increased to require 20% renewables by 2020, but there are currently no geographic restrictions on where the renewable resources are located. On the other end of the spectrum, Montana's resources must come from within the state, or from out of state facilities that deliver electricity into the state from facilities that went into service after 2004. New Mexico also requires any out of state resources to deliver electricity into the state. Most states allow resources from anywhere within the region, or electric control area, to count toward RPS compliance.[213]

Eligibility of Existing Resources

The Massachusetts RPS only requires four percent of the state's retail sales to come from renewables by 2009 but these must be "new" renewables,[214] and biomass resources must meet stringent emissions standards. Given the resource and siting constraints in New England, this low percentage requirement will actually require fairly substantial development of new resources.[215] In neighboring Maine, until recent revisions requiring the addition of "new" renewables, the state's 30% renewables requirement would have virtually no impact since existing renewables are eligible under the RPS.[216] New York's

[212] This is Minnesota's RPS requirement for Xcel.

[213] Some of these states, like Massachusetts, allow resources from adjacent electricity control areas as well as long as the electricity is delivered into the state's control area.

[214] New renewables in Massachusetts are defined as those generators (or capacity additions at existing plants) that went into service after 12/31/97.

[215] Entities with RPS obligations can also comply with the Massachusetts RPS by making ACP payments, and capacity additions at existing renewable energy plants are occurring and may continue to occur in addition to the development of new renewable energy generators.

[216] In June, 2006, legislation passed setting a goal to increase the state's "new" (post 9/1/05) renewables by 10% over 2007 levels by 2017 (DSIRE).

24% by 2013 requirement also counts existing resources. Since 19% of the state's electricity already came from renewables at the time the RPS went into effect, the RPS will only result in a five percent increase in "new" renewable resources.[217]

Eligible Technologies

Some of the more recent portfolio standard policies with high percentage requirements are actually "environmental portfolio standards" rather than renewable-specific standards because they include load reduction, non-renewable on-site generation, and/or non-electric generating renewables (i.e. solar hot water) in their definition of eligible renewables. For example, Arizona, Hawaii, Nevada and Pennsylvania all count energy efficiency savings toward their overall targets. Arizona recently replaced its solar set-aside with a distributed generation set-aside. Distributed generation must account for 30% of the portfolio requirement by 2011.[218]

Enforcement, Penalties and Alternative Compliance Mechanisms

Illinois' RPS sits on the lenient end of the spectrum in that its 7% by 2013 goal is voluntary.[219] In Minnesota, the non-compliance penalty may not exceed the cost of building or procuring renewable energy resources in the market. Arizona's compliance rules are somewhat stricter but are not well defined; entities that fail to comply are required to submit a plan for making up the compliance shortfall, and costs to recover the shortfall are not recoverable. Like New Jersey, several states have alternative compliance payment (ACP) mechanisms. Some ACPs are limited in their effect, like Delaware's ACP which is $25/MWh and is only required of entities that fail to comply for two years in a row. Other ACPs can be very costly for non-compliant entities. In the District of Columbia and New Jersey, solar ACPs are $300/MWh. In Pennsylvania the solar ACP is 200% of the market value of solar RECs.[220]

Additional key RPS features such as ACP mechanisms, compliance costs, strategies to increase the development of target technologies, and the role of RECs are discussed in the following sections. At the end of each section, the situation in New Jersey and relevant considerations for New Jersey are discussed.

4.4.2 Treatment of Different Resource Types

[217] Saintcross, John, "New York State Renewable Portfolio Standard." Presented at the EUCI RPS Conference, Westminster, CO, April 24, 2007.

[218] This equates to 4.5% of total electricity sales by regulated utilities.

[219] In May, 2007, the Illinois House of Representatives passed a bill requiring the state to source 25% of its electricity from renewables by 2025. The bill had not yet been passed by the Senate at the time this report was completed.

[220] Database of State Incentives for Renewable Energy (DSIRE).

While RPS policies favor the more cost-effective resources like landfill gas and wind, some states are taking steps to ensure that RPS demand extends to less competitive resources as well. Seven states and the District of Columbia have **solar set-aside requirements** in their RPS policies:[221]

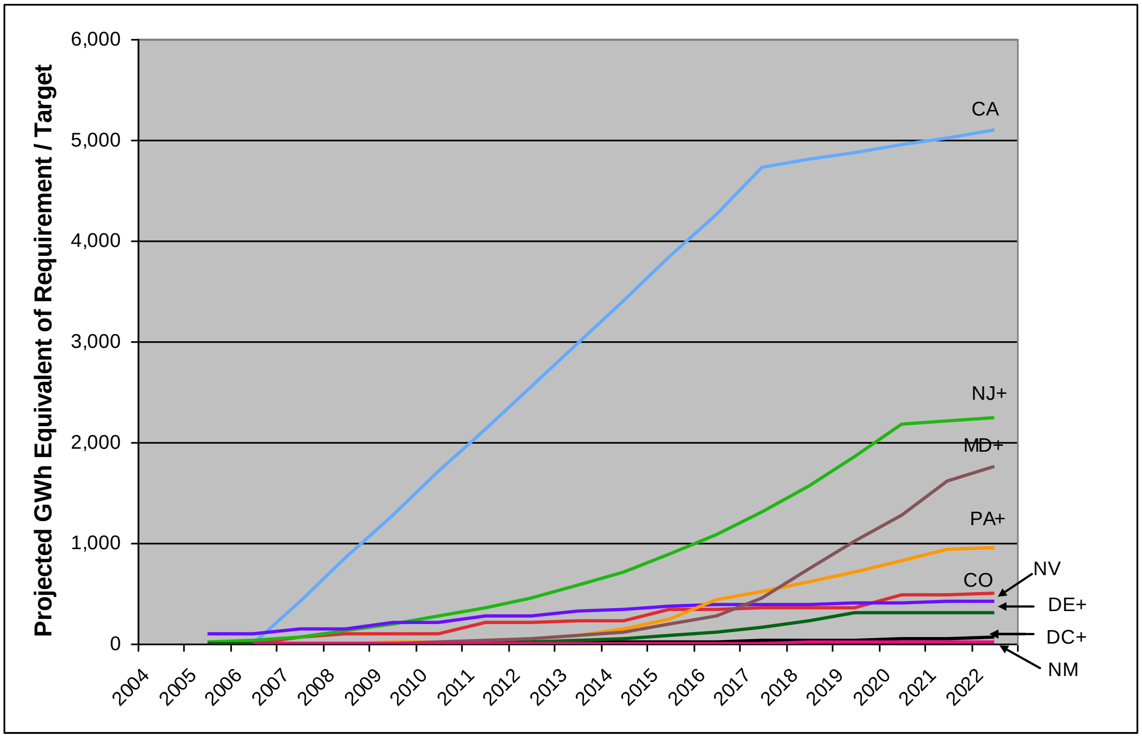
- Colorado: Of the renewables requirement for each year, four percent must come from solar electric. Of this amount, at least half must come from customer-sited systems.
- Delaware: By 2019, 2.005% must come from solar electric resources.
- District of Columbia: By 2022, 0.386% must come from solar electric resources.
- Maryland: By 2022, 2% must come from solar electric resources.
- Nevada: Of the renewables requirement for each year, five percent must come from solar energy systems. It is important to note that PV resources receive a 2.4 multiplier for compliance purposes, and customer-sited PV may receive an additional 1.05 multiplier.[222]
- New Jersey: By 2021, 2.12% of total retail sales must come from solar electric resources.
- New Mexico: By Of the renewables requirement for each year, 20% must come from solar electric, as long as the cost of compliance does not exceed the state's cap.[223]
- Pennsylvania: By 2021, 0.5% of total retail sales must come from solar electric sources.

[221] Arizona used to have a solar set-aside, but this was recently replaced with a distributed generation requirement. By 2011, 4.5% of total electricity sales must come from distributed generation resources. Data on RPS solar set-asides is current through August, 2007.

[222] In Nevada and Pennsylvania, solar hot water is an eligible solar resource.

[223] The cost cap is set at 1% of total electricity charges in 2007. It will increase a rate of one-fifth of a percent each year through 2011 at which time it will remain fixed at 2%. In August, 2007, New Mexico's Public Regulation Commission replaced the state's 300% solar multiplier with an RPS solar set-aside (http://www.nmprc.state.nm.us/renewable.htm).

Figure 4-3. RPS Solar Set-Asides and Development Targets by State[224]



Source: Database of State Incentives for Renewable Energy

Another state with a notable solar target is California. In 2006, the California Public Utility Commission set forth a goal of achieving 3,000 MW of installed PV capacity in the state by 2017.[225] While unprecedented among U.S. states in its magnitude, California's target is similar to New Jersey's in the challenge that it represents because California has a much larger geographic territory and population, as well as a greater solar resource than New Jersey.

Two states have **wind-set asides** in their RPS policies:

- **Illinois**: 75% of total portfolio must come from wind
- **Minnesota**: 25% of Xcel's supply must be generated by wind by 2025

In Texas, where wind is the most readily-developed renewable resource, the state has actually set a non-enforceable goal to develop at least 500 MW from non-wind resources. The state's ultimate RPS requirement is 5,880 MW by 2015.

In some states, **multipliers** are used to increase the value of target resources for RPS compliance purposes:

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[224] While California's solar development goal is not included as a requirement within its RPS, it is included in the graph for comparison purposes.

[225] This goal is not included in the state's RPS goals.

- **Delaware**: In-state solar and energy from fuel cell receives 300% credit toward compliance. In-state wind from wind turbines operational before December 31, 2012 receive 150% credit toward compliance.

- **Maryland**: For 2006-2008, wind receives 110% credit towards compliance. Through 2008 methane receives 110% credit towards compliance.[226]

- **Nevada**: 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.

- **Washington**: Distributed generation receives a multiplier of 2 for compliance purposes. Facilities developed after December 31, 2005 using apprenticeship program receive multiplier of 1.2 for compliance purposes.

New Jersey: Status and Issues for Consideration

As discussed in Section 2, New Jersey's solar set-aside presents the state with unique challenges in that solar project economics must be favorable enough to attract incredibly high levels of investment, second only to California- a state with greater land area and solar resource, as well as a larger population.

4.4.3 Alternative Compliance Mechanisms

There is a great deal of scrutiny over the level at which the ACP and SACP levels are set. Some stakeholders feel that ACP levels should be set at levels double the REC trading values to ensure that they provide a sufficient incentive to participate in the marketplace and, ideally, enter into long-term contracts with generators. However, an additional purpose of the ACP is to limit ratepayer exposure to risk in the event of a supply shortage in which LSEs would be dependent on ACPs to meet RPS requirements.

[226] Previously, solar received a 200% credit towards compliance. This multiplier was replaced in April, 2007, by a solar set-aside of 2% by 2022.

Table 4-3. Comparison of ACP Levels[227]

State	ACP / Compliance Penalty
Connecticut	$55/MWh
DC	$25/MWh Tier 1 $10/MWh Tier 2 $300/MWh Solar
Maryland	$20/MWh Tier 1 $15/MWh Tier 2 Solar: $450/MWh in 2008, $400/MWh in 2009, declining by $50/MWh annually until reaches $50/MWh in 2023 and beyond.
Delaware	$25/MWh, up to $50/MWh if multiple years of non-compliance Solar: Begins at $250/MWh for first use, increases to $300/MWh with second use and to $350/MWh with third use
Massachusetts	$50/MWh, initially (adjusted annually by CPI, adjusted to $57.12/MWh for 2007)
New Jersey	$50/MWh non-solar $300/MWh solar through 2008 Reporting Year[228]
Pennsylvania	$45/MWh 200% of market price for solar during Reporting Year
Rhode Island	$50/MWh (2003 dollars, adjusted by CPI)

Source: Database of State Incentives for Renewable Energy

New Jersey: Status and Issues for Consideration

The current SACP in New Jersey is set at $300 per MWh, and several other states' ACPs are set in the range of $50 per MWh. Alternative Compliance Payment (ACP) and Solar ACP (SACP) levels were established in New Jersey through a 2003 Board Order as a tool to:

> "provide(s) a 'back-stop' mechanism that protects suppliers, as well as consumers, from the cost implications of excessive market risk. The ACP and SACP set an upper limit for the cost of RPS compliance; remove the risk of unknown financial penalties for any renewable energy shortfalls; provide protection against the possibility of market power exertion and unforeseen scarcity of renewable energy and REC shortages; and gives suppliers some flexibility in complying with RPS requirements."[229]

[227] Current as of March 2007.

[228] For 2009 and beyond, an 8-year rolling schedule was adopted by the Board September 12, 2007. The schedule is as follows: $711 (2009), $693 (2010), $$675 (2011), $658 (2012), $641 (2013), $625 (2014), $609 (2015), $594 (2016).

[229] December 18, 2003 NJBPU Order.

The RPS regulations stipulate that the BPU must review the ACP and SACP levels at least annually in collaboration with an ACP Advisory Board.[230]

The ACP and the SACP have remained at their original 2004 levels—$50/MWh ACP, $300/MWh SACP (about $80 more than the current average SRECs trading value)—and will continue to remain at that level through Energy Year 2008 (ending May 31, 2008). The NJ BPU recently issued a Board Order increasing the SACP for 2009, and establishing an eight-year rolling SACP schedule with a starting value of $711/MWh, declining at a rate of three percent annually.[231] This level was set based on the SREC values needed to provide PV project owners with a 12% IRR, plus $100. The $100 adder was intended to put the SACP level high enough above the target market price to make it worthwhile for suppliers to buy SRECs rather than pay the SACP (assumes transaction costs are less than $100/SREC).

Rebates for large (~40 kW) PV systems will not be available when the new SACP levels take effect. SREC revenue will function as a form of performance-based incentive for projects, albeit an uncertain revenue stream.

4.4.4 Role of RECs and REC Markets

Two key distinctions regarding the mechanisms states use to track RPS compliance include: 1) whether the state uses Renewable Energy Certificates (REC) for compliance or whether it requires renewable electricity to remain bundled with its attributes, and 2) whether the state participates in or provides a web-based, user-accessible tracking system. As of April, 2007, only three of the 23 U.S. jurisdictions with RPS policies (Arizona, Iowa and Minnesota) require attributes to remain bundled with the underlying renewable electricity for compliance purposes.[232] Of the remaining states with RPS policies, 11 of them participate in web-based, user-accessible tracking systems, and several more states are in the process of launching such systems.

REC trade is playing an increasingly significant role in renewable energy markets across North America and Europe.[233] By facilitating the "unbundling" and separate transaction of renewable energy attributes and the associated energy commodity, RECs reduce geographic (i.e., mismatch between strong renewable energy resource areas and electricity load centers), intermittency of operation and other renewable energy development barriers. RECs, therefore, make renewable energy markets more fluid and can help reduce the costs of complying with RPS policies. Certificate tracking systems provide a flexible mechanism for disclosing energy supply sources to consumers, and for demonstrating compliance with RPS and other environmental policies. In addition, they improve the

[230] New Jersey RPS Rules: N.J.A.C. 14:4-8.10 (b) and (c)

[231] The Board Order was approved on September 12, 2007.

[232] There has been significant debate around the use of RECs in California; however, the state has indicated that it will allow RECs to be used for RPS compliance once a REC tracking system is in place. Since California played a key role in developing the WREGIS tracking system which became operational in July, 2007, it is assumed here that California will allow RECs to be used for RPS compliance. It should also be noted that Iowa has already met its RPS goal so lack of a certificate tracking system in that state is not necessarily an indication of a lack of support for unbundling of RECs.

[233] RECs represent the attributes (i.e., fuel type, location, emissions, RPS-eligibility) associated with a unit of renewable energy (1 MWh = 1 REC).

credibility of renewable energy markets.[234] The environmental attributes of each unit of energy are systematically monitored from their point of generation to their point of retirement, thus helping to avoid the double counting of attributes. While regional REC tracking systems ensure that a REC will not be double counted within that tracking system, since there is not a nationwide tracking system, it is impossible to confirm that a renewable energy generator has not attempted to sell environmental attributes in multiple markets. At this time, renewable energy markets depend on contract terms and affidavits in which generators ensure that their environmental attributes are being sold only once.

A variety of certificate tracking systems are in operation in the U.S. today. The most robust tracking systems are the New England Generation Information System (NE-GIS), the PJM Generation Attribute Tracking System (GATS), and the Texas ERCOT tracking system. The territory of each of these systems corresponds with an electricity control area. In the case of the NE-GIS and GATS, all units of energy, not just renewable energy, are tracked in the system. Other systems, ERCOT, the Wisconsin Renewable Resource Credit system (WI-RRC) and the New Jersey Solar REC system (NJ-SREC), track only renewable energy resources. According to APX, a company that has played a key role in the development and implementation of certificate tracking systems throughout North America, as of April, 2007 there were 625 account holders and more than 400 companies represented in the NE-GIS, PJM and ERCOT trading systems, and more than two billion certificates are tracked annually through these three tracking systems.[235]

Three new certificate tracking systems are under development. The Western Renewable Energy Generation Information system (WREGIS) has the ability to track RECs in 13 western states.[236] The Midwest Renewable Energy Tracking System (M-RETS) covers certificate tracking in five U.S. states and Manitoba.[237] Both WREGIS and M-RETS went online in July, 2007 and both are operated by APX. Unlike NE-GIS and PJM, the western and mid-western tracking systems will track renewable energy certificates only (not the attributes of all electricity produced in the region). In addition, New York is considering introducing its own certificate tracking system. The territories covered by the REC tracking systems discussed above are shown in Figure 4-4.

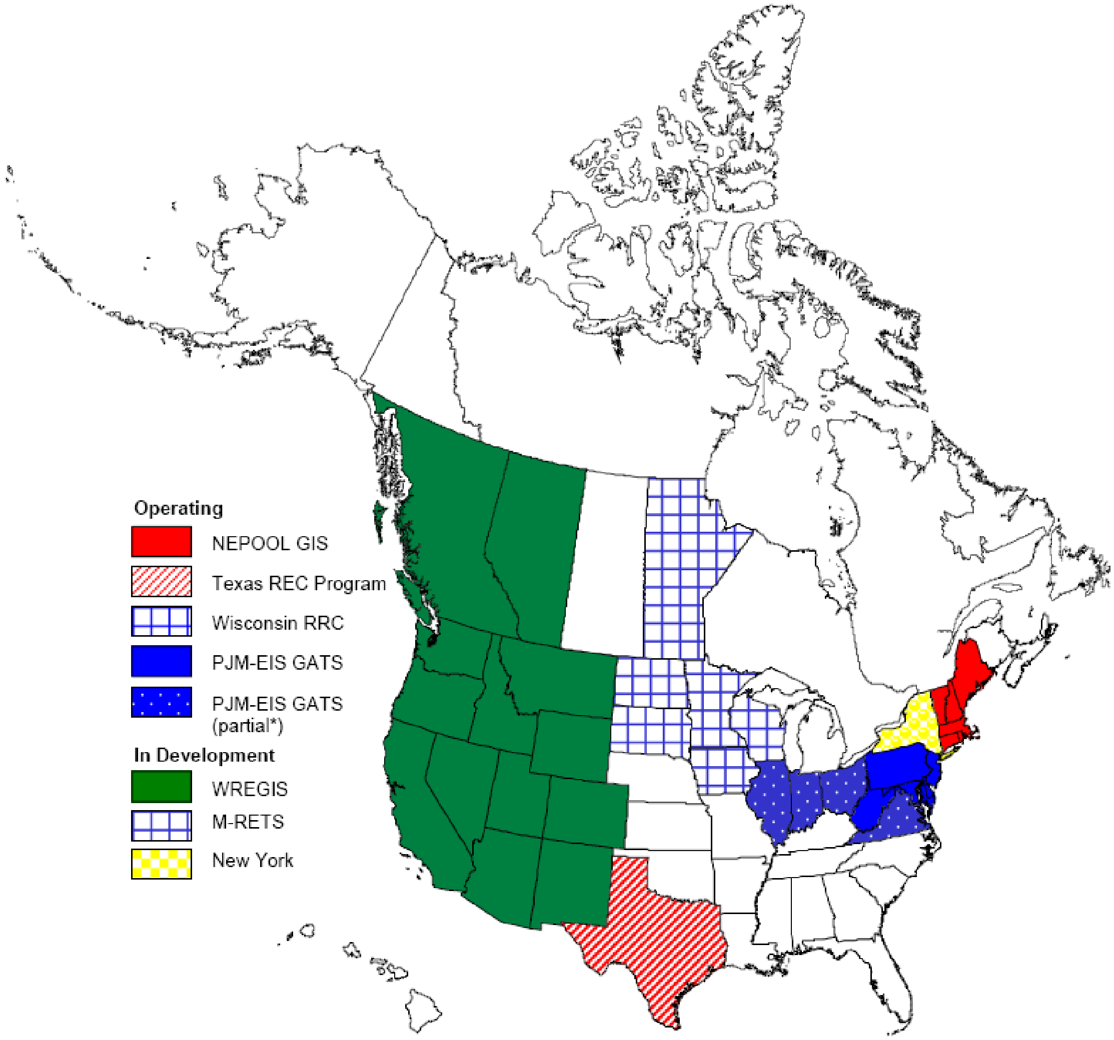
[234] Both the PJM GATS and New England GIS tracking systems track attributes associated with all electricity in those regions, not just renewable energy attributes. However, for the purposes of this discussion, we refer only to "REC tracking systems."

[235] Melby, John. "US REC Market, Status and Trends." Presented at the EUCI RPS Conference, Westminster, CO, April 24, 2007.

[236] http://www.westgov.org/wieb/wregis/

[237] http://www.mrets.net/

Figure 4-4. Territories Covered by North American REC Tracking Systems



* GATS (partial) indicates that portions of these states, and others not similarly indicated, are within the PJM footprint.
** New Jersey also supports a separate Solar RECs tracking system.

Source: Holt & Wiser, 2007

Some states that use RECs for RPS compliance provide additional flexibility mechanisms, such as banking of RECs and multi-year REC life, to improve the liquidity of the REC markets. In PJM GATS, certificates typically only have a lifetime of one year, but account holders can establish Clean Energy Portfolio Standard (CEPS) Sub-accounts into which certificates can be deposited and used for later RPS compliance in accordance with a given state's rules. In the PJM territory, Delaware, the District of Columbia and Maryland all allow RECs to be used for RPS compliance for up to three years after the year in which they were created. Pennsylvania has a REC banking provision which has an effect similar to the extended REC lifetimes allowed in the other three PJM jurisdictions (Weiner et al., 2005). Under a recent New Jersey Board Order, New Jersey will extend the trading lifetime of SRECs to two years.[238]

RECs play a fairly minimal role in project economics in most of the states in which the Summit Blue team conducted interviews. In states like Washington, Wisconsin and Delaware, RPS policies are still very new and compliance mechanisms have not been finalized. In Oregon, where no RPS policy is currently in place, there is limited demand for solar RECs. These RECs were previously being sold into the voluntary market, but since the former buyer shifted focus, the RECs from PV systems in Oregon are not currently being sold and effectively, have no value.

REC ownership has recently become a major issue in states like California because of the potentially high value RECs can hold. In California, the CPUC ultimately determined that solar system owners would gain title to the RECs associated with electricity produced from their solar systems (Decision 07-01-018, January 11, 2007). Therefore, systems participating in the CSI can receive revenue both from REC sales and from their incentive payment(s). In Massachusetts and Delaware, owners of systems receiving incentives also retain ownership of RECs for the life of the system.

In contrast, in New York, where there is currently no REC trading system used for RPS compliance, NYSERDA takes ownership of RECs for the first three years of a system's operation, then REC ownership reverts to the system owner.[239] In Oregon, owners of systems funded by ETO retain REC ownership only for the first few years of a system's operation (five years for residential systems and two years for commercial systems).[240] In Wisconsin, We Energies takes ownership of all RECs created by systems funded through the program because they are used to supply the utility's green power product.[241]

4.5 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.

[238] The Board Order was approved at an Board agenda meeting on September 12, 2007 and was signed December 6, 2007. The changes specified in the Order are subject to rulemaking.

[239] Peterson, Jeff (New York State Energy Research and Development Authority), personal communication, February 27, 2007.

[240] Brockman, Kacia (Energy Trust of Oregon), personal communication, March 1, 2007.

[241] Lynch, Scott (State of Delaware Energy Office), personal communication, January 5, 2007.

4.5.1 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.[242] 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).[243]
- 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 shortages, as in Massachusetts, this drives compliance costs up to the cap. 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. 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.

[242] 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.

[243] California Public Utilities Commission. "Renewable Energy Certificates and the California Renewable Energy Portfolio Standard program." Staff White Paper. April, 2006.

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. California and Nevada also require LSEs to enter into long-term contracts. However, in the case of Nevada, a lack of utility creditworthiness has limited the execution of long-term contracts.[244]

As evidenced by the fact that numerous Texas wind projects that have been financed through low-price, long-term contracts (Table 4-4), 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.[245]

A variety of other mechanisms exist for capping RPS compliance costs, such as limiting the RPS costs to a maximum percentage of total electricity sales, or limiting the percentage impact on the average ratepayer's bill. 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 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

[244] 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.

[245] 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.

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 4-4. Early RPS Experience

State & First Compliance Year	Comments
Arizona (2001)[246]	• As of 2004, RPS-obligated entities had reportedly fallen short of compliance without repercussions.[247]
California (2003)[248]	• 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.[249] • 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)[250]	• 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.[251]

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

[247] 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.

[248] 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.

[249] 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.

[250] 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.

[251] 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."[252]
Maine (2000)	• No cost impacts since requirements set below level of renewable energy already generated in the state.
Massachusetts[253] (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.[254]
Nevada (2001)	• As of 2004, RPS was effectively driving development of new resources with contract pricing ranging from 3-5.5 cents/kWh.[255] • 287 MW of geothermal, wind and solar resources are under contract with utilities for ~20 year terms.[256] • 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.

[252] 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.

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

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

[255] 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.

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

State & First Compliance Year	Comments
New Jersey (2001)[257]	For 2006 Reporting Year: • A total of 19 ACPs were made toward Class I compliance ($950 revenue), and 163 SACPs were made toward solar compliance ($48,900 revenue). • Of the Class I RECs that were contracted for directly by suppliers, all came from landfill gas plants located in New Jersey.
New Mexico[258] (2006)	• For first compliance year (2006), all utilities are expected to fulfill requirements. • REC expenditures ($/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[259]	• $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.[260] • Weighted REC price for Main Tier contracts is $17/MWh. • Expected to meet 80% of 2008 program goal.

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

[258] 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.

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

[260] 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.

State & First Compliance Year	Comments
Texas (2002)	• Deemed lowest cost RPS compliance costs of any state. • Long-term wind contract pricing in 3 cent/kWh range.[261] • 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).[262] • 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.[263]

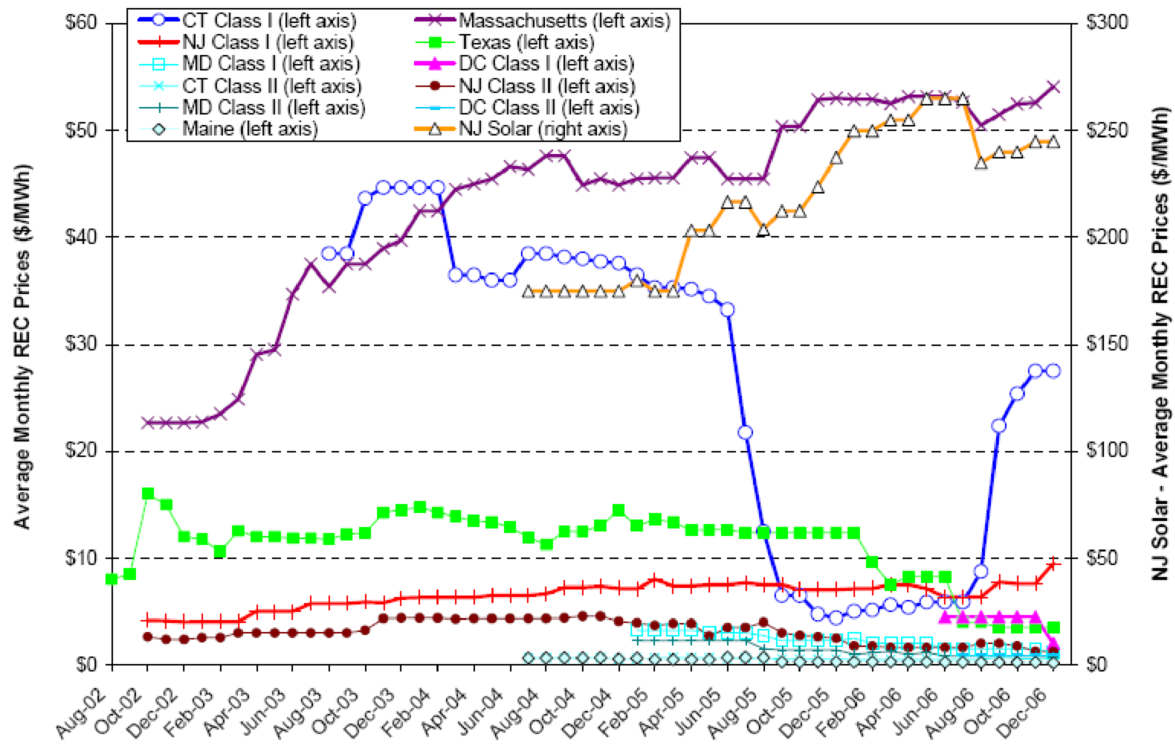
In the absence of more robust empirical data regarding early RPS compliance costs, one can look to REC pricing as one indicator of RPS cost impacts. Figure 4-5, presents REC pricing data for RPS markets that use RECs to demonstrate compliance. These data were collected by the Lawrence Berkeley National 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.

[261] 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.

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

[263] Ibid.

Figure 4-5. REC Pricing



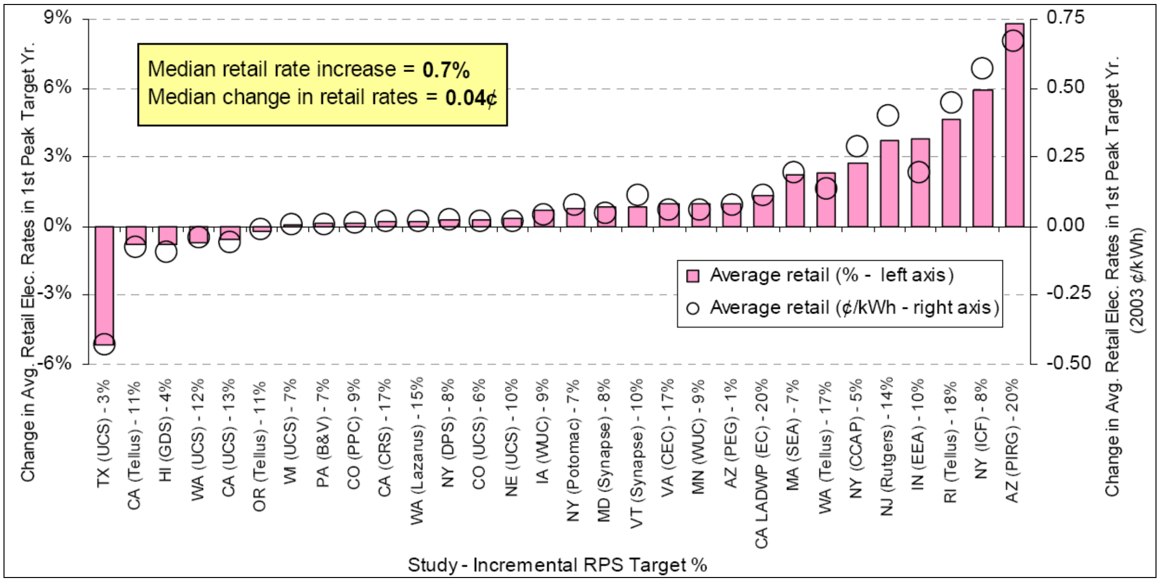
Source: Wiser, R. C. Namovicz, M. Gielecki, and R. Smith. "Renewables Portfolio Standards: A Factual Introduction to Experience from the United States." Lawrence Berkeley National Laboratory, April, 2007. Based on data from Evolution Market's monthly pricing reports compiled by Lawrence Berkeley National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

4.5.2 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.[264] Seventy percent of RPS cost studies reviewed predict that retail rates will increase by no more than one percent under base-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 4-6). The median bill impact across all of the studies was $0.38 per month.

264 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.

Figure 4-6. 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.

5 SOLAR PV MARKET TRANSITIONS SCENARIOS

5.1 Qualitative Review of Solar Market Transition Scenarios

5.1.1 Introduction

This section includes a discussion of a qualitative assessment of potential solar market transition scenarios being considered by New Jersey, as well as a discussion of analysis of the ratepayer impacts associated with those scenarios. The analysis was conducted in an effort to provide the BPU with timely and unbiased assistance in its efforts to rapidly transition the New Jersey solar market from a dependence on up-front rebates to a market-based structure in which SREC[265] or other performance based project financing can play a greater role in supporting the level of market growth necessary to meet the state's renewable portfolio standard (RPS) requirements.

Seven transition models were considered: four models that were formally proposed by representatives of New Jersey's RPS Transition Working Group, a baseline model (continued rebates), and two additional models that were deemed relevant through discussions with the BPU staff and stakeholders. In the qualitative assessment, discussed first in this section, the strengths and weaknesses of each transition strategy were evaluated using a set of criteria developed based on the guiding principles for the solar market transition set forth by the BPU. Results of the assessment and the relative shift in risk associated with each transition strategy are discussed at a summary level, but readers are referred to the full report, "Preliminary Review of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market Based Incentives," for a more detailed discussion. In the ratepayer impact analysis, the Summit Blue team worked with the BPU and members of the solar industry and investment community to determine the appropriate standard assumptions for use in modeling all seven market transition scenarios. Baseline ratepayer impact estimates were calculated, and additional analysis was completed to identify the most sensitive modeling parameters and to demonstrate the range of potential ratepayer impacts given possible variation in those key assumptions. As with the qualitative assessment, summary level discussion only is presented in this report. For a complete discussion of the ratepayer impacts analysis, the reader is referred to the full report, "An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives."

5.1.2 Background Regarding the Need for a Transition

New Jersey's RPS requires 2.12% of total electricity sales in New Jersey to come from in-state solar electricity generators by 2021. The BPU's Customer Onsite Renewable Energy program (CORE) is the focus of the solar market transition, as it has been the source of rebate funds that have fueled the

[265] The New Jersey Renewable Portfolio Standard Rules (N.J.A.C. 14:8-2.2) define a Solar REC as "a type of REC, as defined in this section, issued by the Board or its designee, which represents the environmental benefits or attributes of one megawatt-hour of solar electricity generation, as defined in N.J.A.C. 14:8-1.2."

rapid pace of solar development in the state to date. From the launch of the BPU's Clean Energy program in 2001 through the end of 2006, the BPU incentives had resulted in the installation of approximately 30 MW of solar capacity in New Jersey. This PV system capacity represents nearly 2,000 customer-sited solar installations.[266] This rapid pace of project development will need to continue, as over 1,500 MW of solar capacity will be needed to meet solar RPS requirements for 2021.

The program's budget is fully committed and there is a queue of nearly 1,600 project applications, representing over 63 MW of potential PV capacity at some stage in the application process. If all of these projects move forward, the dollars required for rebates would substantially exceed the resources available in the annual program budget.[267]

No plan yet exists for the disbursement of financial incentives beyond the BPU's current four-year funding cycle ending on December 31, 2008, and uncertainty about the future direction of New Jersey's solar market is placing strain on the local solar industry. As specified in the Electric Discount and Energy Competition Act (N.J.S.A. 48:3-61), the New Jersey legislature seeks to develop Clean Energy programs that can operate without rebates. Therefore, as New Jersey decides how to support solar project development in the next funding cycle, there is an emphasis on transitioning away from the current rebate-centered solar incentive structure to one that is more focused on market-based mechanisms.

New Jersey's rebates, combined with the Federal tax incentives, have historically reduced the upfront cost of solar projects by between 50 and 100 percent. This has kept the portion of project investment supported by third-party financing much smaller than what would be necessary in a post-rebate solar market.[268] If rebates are no longer offered, long-term contracting will become increasingly important because the investment community seeks certainty in project revenue streams. Given the dynamic nature of REC markets, SREC revenues will inherently vary over time. Without the revenue certainty provided by long-term contracts or other means, the financial community will, according to solar developers, discount the value of the revenue stream by as much as 90%.[269]

This discounting of future revenue streams is due in part to the relative newness of REC markets and the regulatory uncertainty surrounding the market. While REC markets have existed for nearly a decade, they are still relatively immature and there is a view that RPS policies could change at any time. The discounted value of future REC streams effectively places a risk premium on project development making solar project financing both more difficult to secure and more expensive (i.e., higher interest rates).

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[266] Based on CORE program records as of December 5, 2006.

[267] Data is sourced from BPU program records as of December 5, 2006.

[268] According to the BPU staff, a wide variety of project financing arrangements have existed under the current rebate incentive system in New Jersey. Finance arrangements have included payment with cash and credit cards, home equity, power purchase agreements, secured and unsecured loans, government borrowing, and DEP financed infrastructure trust financing.

[269] These values are based on information provided by authors of the Auction Set Pricing / Standard Contract Model. The values were verified through interviews with members of the financial community. Other representatives from the industry have echoed this concern about the discounting of future REC revenue streams.

One strategy many renewable energy project owners use to secure a certain REC revenue stream is to enter into long-term contracts for the sale of RECs. However, it is difficult for New Jersey solar projects to secure long-term contracts with electricity suppliers due to the Basic Generation Service (BGS) system in place in the state.[270] Each year New Jersey's Electric Distribution Companies (EDCs)[271] procure one third of their load for a three-year period. The winning bidders become BGS suppliers and have to meet all the requirements of being a PJM Load Serving Entity (LSE) in New Jersey, including satisfying the RPS requirements. Because the BGS contract term is only three years, BGS suppliers are typically unwilling to sign SREC contracts for longer than that period of time.[272]

Members of an RPS Transition Working Group in the state have discussed a number of potential strategies for transitioning away from rebate incentives. At the time the research team conducted its review during the fall of 2006, four alternative solar market transition strategies had been proposed. Each of the proposed models offers some mechanism for providing PV system investors with a level of revenue certainty in a post-rebate market, and each was developed with an effort to adhere to the guiding principles set forth by the BPU.

5.1.3 Summary of Solar Market Transition Models

Representatives of the RPS Transition Working Group proposed four alternative solar market transition models. These models are summarized below.

Underwriter Model

The proposed underwriter program would provide a mechanism for projects to receive a 15-year commitment from an underwriting entity (proposed to be the New Jersey Economic Development Authority) to purchase unsold SRECs from the projects at a pre-determined value, effectively setting a "floor" price. This commitment provides SREC price certainty which eliminates some investment risk and can help projects secure financing.

The authors of the model proposed funding the underwriter program with in-year revenue from Alternative Compliance Payments (ACP).[273] To maintain a balance between supply and demand, the underwriter would limit its commitments to the amount of capacity necessary to meet RPS requirements. The SREC floor value would be set by the ACP Board at a level high enough to enable projects to recover the cost of capital, but low enough so that project owners would still have an incentive to go out to the open market to sell their SRECs. The authors noted that SRECs are trading at 65 to 90 percent of SACP value and that the underwriting price should be about 60 percent of the SACP. They also suggest that the program issue new underwriter commitments for a period of ten years.

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[270] BGS is the default electricity supply option in New Jersey.

[271] New Jersey's EDCs include PSEG, Atlantic City Electric Company, Jersey Central P&L, and Orange & Rockland Electric Company.

[272] More information on the BGS auction process can be found at http://www.bgs-auction.com/bgs.auction.overview.asp.

[273] New Jersey's suppliers/providers of electricity can comply with the RPS either by acquiring RECs / SRECs or by using the Alternative Compliance Payment (ACP) mechanism. The current ACP is $50/MWh for non-solar resources. A separate ACP level exists for solar (SACP) and is currently set at $300/MWh.

Commodity Market Model ("Underwriter + Rebate")

Under this proposed system, the underwriter program (as described above) would be adopted but rebates would continue to be available for systems smaller than 100 kW through 2011.[274] The authors of this model propose increasing the SACP to at least $650/MWh.

Hybrid Tariff Model[275]

The proposed model would provide projects with a stable, long-term revenue source by having Electric Distribution Companies (EDCs) issue premium payments/credits to solar project owners on a per kWh basis. Different tariff rates would be paid to different categories of project owners depending on varying project finance needs and the BPU's interest in advancing specific policy goals. Tariff revenue would be supplemented by additional SREC revenues that project owners would receive from participation in the SREC market. Because project owners would recover their investment both through revenues from tariff payments and from SREC sales, the model is identified here as a "hybrid" tariff system.

Auction Set Pricing, Standard Contract Model

SREC prices would be set in an annual auction in which approximately 25 percent of the SRECs required to fulfill RPS goals for the following compliance year would be auctioned to LSEs. The authors of this model note that the auction would be similar to that which currently occurs annually for Basic Generation Service (BGS). In an effort to reduce transaction costs and make it easier for LSEs to enter into SREC contracts, the BPU would develop a standard contract for all LSEs to use for SREC purchases. LSEs would only be held responsible for RPS compliance shortages via the ACP if they chose not to participate in the auction-set pricing / standard contract system. PV systems in New Jersey would only be eligible to produce SRECs during their first five years of operation. This would require systems to receive higher SREC prices during their short economic lifetimes than they would if system costs were amortized over a longer period (such as the 10-15 year economic time horizon applied under other proposed strategies).

Additional transition models considered as part of the analysis are summarized below.

SREC-Only Model

The BPU recently launched a pilot program intended to enable projects to be built and be eligible to generate SRECs without receiving a rebate through the over-subscribed CORE program.[276] Projects

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[274] The proposed system would also involve extending the trading lifetime of RECs to 2 years and enabling large scale (>2MW) solar facilities to generate SRECs.

[275] The Board of Public Utilities' Office of Clean Energy has indicated that as part of its review of a draft of Summit Blue's qualitative solar market transition assessment 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 as part of its ongoing proceeding. The purpose of the analysis was to review a range of options for renewable incentives in New Jersey for comparative purposes.

[276] Previously, participation in the CORE rebate program was required for solar projects to generate New Jersey SRECs.

would be fully dependent on SREC sales revenue (plus avoided electricity costs and federal tax incentives) to recover the cost of their solar investment. Project owners are required to register with the BPU, demonstrate that the project is already under contract, and share the project's financial pro forma with the BPU.

Full-Tariff Model

While not submitted as a formal proposal, through interviews with industry stakeholders, the research team determined that a full-tariff system should also be considered as a market transition option. The fundamental distinction between a full tariff system and the hybrid tariff system described above is that tariff payments under the full-tariff system would be large enough so that systems could rely solely on tariff revenues in order to be economically viable. Since no formal proposal was submitted, it is not clear what proponents of a full-tariff program would envision as the future role of the SREC program. For the purposes of this discussion, the research team assumed that under a full-tariff system, PV system owners would turn their SRECs over to their LSE in exchange for receiving the tariff support. After the term of the tariff commitment is over, project owners would reclaim access to their attributes for sale either into the New Jersey SREC market or elsewhere. For the purposes of this discussion, we also assume that all net-metered systems would have access to the tariff rate structure, but that different tariff rates would be paid to small versus large systems.

Continued Rebates / Baseline Model

This model would involve an extension of SBC-funded up-front rebates for PV owners, and a continuation of the SREC market as it exists today (i.e., no changes in ACP). Rebate levels may be periodically adjusted over time, but would maintain the current goal of providing projects with a 10-year simple payback.

The New Jersey legislature has declared that the state should pursue market-based incentives,[277] and the public debate regarding next steps for the PV market in New Jersey has focused on strategies for transitioning away from a rebate-focused incentive system. However, for the purposes of characterizing a baseline against which other market models can be compared, and to expand the range of alternatives considered, a limited review of a rebate model was included in the analysis.

5.1.4 Evaluative Criteria for Qualitative Assessment

In order to objectively evaluate the merits of solar market transition options, each was reviewed using a set of criteria that reflect the priorities of the BPU and market stakeholders, and that are consistent with elements present in the most successful solar markets. the BPU's guiding principles for the market transition formed the primary basis for developing the list of criteria, but findings from primary and secondary research also informed the development of the criteria. The primary review criteria include:

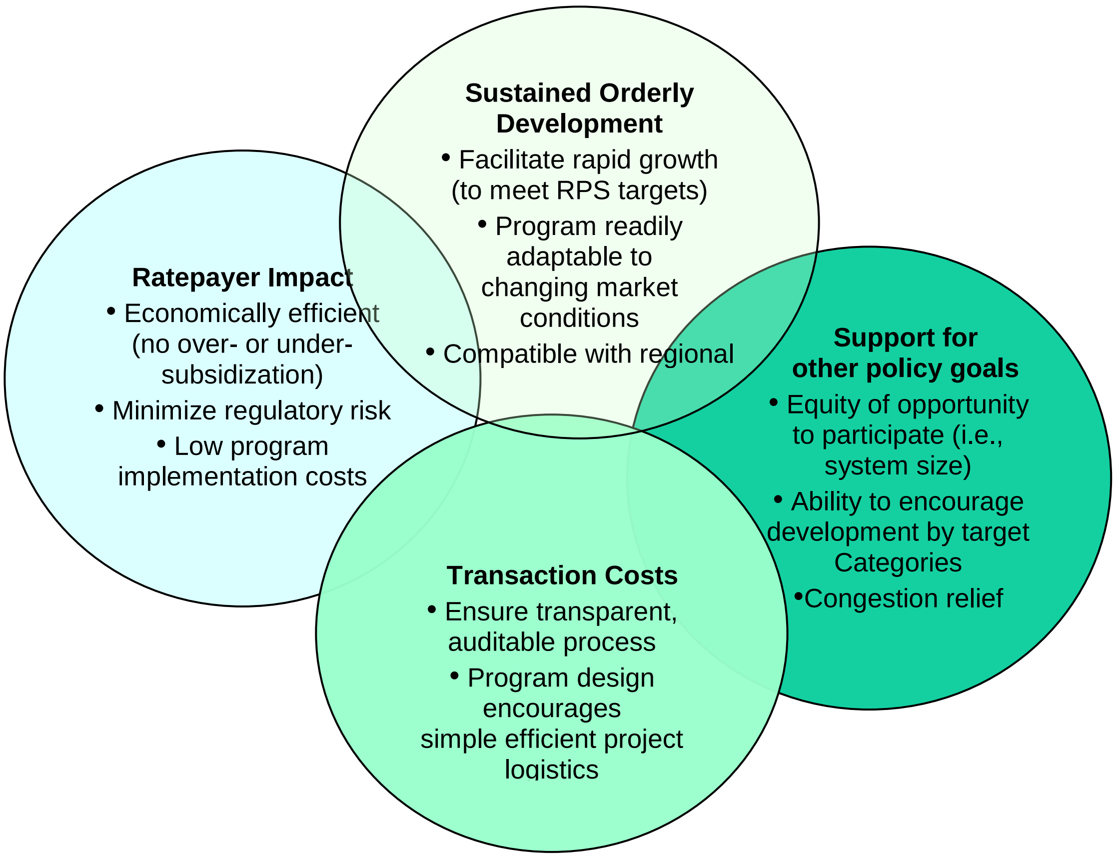
- Supports sustained orderly development
- Low transaction costs

[277] As specified in the Electric Discount and Energy Competition Act at N.J.S.A. 48:3-61, the New Jersey legislature seeks to develop Clean Energy programs that can operate without rebates.

- Low ratepayer impact
- Support for other policy goals

These primary criteria, and the associated secondary criteria, are presented in Figure 5-1 and described briefly below.

Figure 5-1. Evaluative Criteria



Sustained, Orderly Market Development

As mentioned above, the overall goal of the RPS, and of the BPU 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 these 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 criterion 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.[278] 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 that is servicing the load. 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. As discussed in Section 2 of this report, **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,[279] and

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

[279] 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).

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.

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.

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 criterion 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.

Ratepayer Impact

The initial qualitative assessment of the transition scenarios was completed prior to the completion of the ratepayer impact assessment. The criteria presented here pertaining to ratepayer impacts were used in the qualitative assessment. They are presented here to document the criteria that were used in the qualitative assessment and because they should still be considered when however evaluating the transition models. However, for the purposes of this report, where we discuss the ratepayer impacts of the transition scenarios, we refer to the results of the detailed ratepayer impact analysis.

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 (see examples listed under "minimizing regulatory risk").

3. **Low program implementation costs**

   This criterion 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 criterion 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.

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. The Director of the BPU's Energy Division has identified the entire state of New Jersey as congested or capacity constrained, making this criteria particularly important.

5.1.5 Strengths and Weaknesses of Market Transition Options, Qualitative Assessment

Key strengths and weaknesses associated with each model are summarized in Table 5-1 and discussed below. It should be noted that none of the models discussed, except the existing rebate program and the commodity market model, addresses an issue that has traditionally been a primary barrier for solar project development- high upfront costs. The transition models assume that with enough certainty in the marketplace, third party financing would be readily available for projects. Based on research conducted as part of this assignment, this assumption seems well-grounded. However, *availability* of third party financing does not necessarily mean that all entities would be willing or able to take advantage of it. Thirty-four percent of CORE program participants surveyed said that they paid cash for their renewable energy system. If rebates were no longer available and upfront costs increased, it's not clear whether potential project owners would be willing to carry debt, and credit problems may be an issue for some potential solar owners as well. This should be considered when considering all of the transition models, except the rebate/baseline model, and the commodity market model, to the extent that small systems would continue to receive rebates for the next few years.

Table 5-1. Key Strengths and Weaknesses of Solar Market Transition Models

Elements	Strengths	Weaknesses
Primary Elements		
Underwriter Related Market Transition Strategies: Underwriter Model and Commodity Market Model	Provides revenue certainty, improving investor confidence Increased access to capital likely Provides growth opportunity for market infrastructure Provides some level of ability of "market forces" to determine SREC pricing within boundaries of floor and ceiling values	As proposed, reliance on ACP as funding mechanism would present significant risks, although an alternative funding mechanism (i.e., SBC funds) could be used Difficult to identify willing / appropriate underwriter entity Potential for unfavorable decisions to lead to market conditions that would "break" the system financially and expose ratepayers to substantial risk Risks associated with underwriter system may limit investor confidence, thus reducing the intended value of revenue certainty offered by the program Requires BPU action to re-set floor level periodically and to monitor dynamic supply / demand balance to determine when to cease new underwriter commitments Does not address upfront project cost barrier
SREC-only market, no minimum revenue guarantees Related Market Transition Strategy: SREC-Only Model	Provides projects possessing the most favorable economic attributes with an opportunity to get built Fosters growth of "market maker" infrastructure (i.e., aggregators and brokers), which facilitates the development of a self-sustaining market	Limits equity of opportunity for small and public projects Difficult for most projects to obtain financing Many installers focused on serving smaller systems would go out of business Added costs to ratepayers associated with higher financing costs, greater use of ACPs, and aggregator and broker services Does not address upfront project cost barrier
Auction-Set Pricing Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model	Allows market-forces to determine SREC pricing Provides transparency in SREC market pricing	Annual occurrence eliminates ability for dynamic market corrections between auction events SREC pricing likely to be driven by largest, most sophisticated players making resulting SREC pricing insufficient for small project owners Substantial administrative burden for state Potential for gaming Does not address upfront project cost barrier

Elements	Strengths	Weaknesses
Mandatory Standard Contract Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model	Reduces transaction costs for buyers and sellers, resulting in lower costs of compliance for ratepayers Increases transparency of transactions	Limits flexibility of contractual relationships Administratively burdensome to enforce compliance BPU costs of developing and updating to keep pace with changing market needs
Hybrid-tariff (tariff + SREC revenue streams, tariff level set to make up ROI not expected to be provided by SREC revenues) Related Market Transition Strategy: Hybrid-tariff Model	Provides revenue certainty, improving investor confidence Can be tailored to match the needs of different project types, and to provide added incentives for development of projects that advance specific policy goals Provides simple solution to limit "windfall profits" of past rebate-funded projects Enables SREC market activity to continue, building market infrastructure that will eventually be needed for a self-sustaining market when no incentives are in place Lowers SREC trading values making NJ SRECs better-aligned with regional solar REC values	May still be difficult to obtain project financing if program's limited revenue certainty fails to sufficiently boost investor confidence Results in both administrative costs of tariff, as well as middleman costs to facilitate SREC trades Requires BPU action to re-set tariff level periodically and to monitor dynamic supply / demand balance to determine when to cease new tariff commitments Does not address upfront project cost barrier
Full-tariff* (tariff revenues only, tariff level set to provide full project ROI) Related Market Transition Strategy: Full-tariff Model	Provides projects with certainty that full target ROI will be achieved Reduces transaction costs by supplying LSEs with SRECs directly from tariff-funded projects Can be tailored to match the needs of different project types, and to provide added incentives for development of projects that advance specific policy goals Provides simple solution to limit "windfall profits" of past rebate-funded projects	Limits development of infrastructure (i.e., brokers / aggregators) necessary to sustain market once program expires May limit third-party owner arrangements Requires BPU action to re-set tariff level periodically and to monitor dynamic supply / demand balance to determine when to cease new tariff commitments. Does not address upfront project cost barrier

Elements	Strengths	Weaknesses
Secondary Elements		
Continuation of Rebates for Small Systems Related Market Transition Strategies: Commodity Market Model	Administratively simple Provides project owners with upfront capital which enables more projects to be built, and may enable self-finance of projects Lower upfront and finance costs should result in lower SREC trading values	Not performance-based, therefore, may result in inefficient use of funds Reduces the project investment amount used as the basis for calculating the value of the federal tax credit for a given project.280
Compressing Project Economics (i.e. to 5 years) Related Market Transition Strategy: Auction-Set Pricing / Standard Contract Model	Increases investor confidence Reduces financing costs	Requires SREC values dramatically higher than those in any other market, thus producing "rate shock" Requires adjustments in RPS requirements, further weakening regulatory certainty of the market as a whole
2-Year SREC Trading Life Related Market Transition Strategies: Commodity Market Model	Increases flexibility of market Provides better planning time horizon for SRECs created toward the end of the Energy Year	Would increase complexity of market monitoring to manage supply / demand balance
Allow Large-Scale (>2MW) PV Systems to Generate SRECS Related Market Transition Strategies: Commodity Market Model	Improves ability to achieve RPS requirements in an efficient manner May reduce overall cost of RPS compliance by putting downward pressure on SREC prices Improves potential to attract development of PV industry manufacturing facility	In absence of other mechanisms to support smaller systems, lower SREC prices could limit ability of SREC market to provide necessary ROI for small systems

[280] Both the personal and corporate federal tax credits are applied to the project investment amount after subtracting the value of any "subsidized energy financing." This certainly includes state-funded rebates, and thus, is shown here as a weakness of upfront rebates. It is unclear how a production-based incentive would be treated for the purposes of calculating the value of the federal tax credit for a given project. Therefore, it is not clear whether this weakness would be shared by production-based incentive structures such as the hybrid or full tariff models.

Elements	Strengths	Weaknesses
Use of PJM GATS as Trading Platform Related Market Transition Strategies: SREC-Only Model	Decreases ratepayer expenditures in support of SREC trading platform Increases ability to trade SRECs with other states in PJM region	Provides no transparency of SREC trading values Not user-friendly for most users, therefore, requires services of an aggregator, broker or other project representative
Limits on Creation / Sale of SRECs for Rebate-Funded Systems*281 Related Market Transition Strategies: Underwriter and Commodity Market Models	Reduces “over-subsidization” / “windfall profits” of projects that already received rebates Avoids excessive ratepayer impacts	Erodes investor confidence by setting precedent for changing rules Reduces ability of early adopters to be rewarded for stepping forward and setting a model for other investors Increases complexity of state’s market rules resulting in increased administrative burden and decreasing appeal to investment community
Template Standard Contract* Related Market Transition Strategies: N/A	Reduces transaction costs for buyers and sellers, resulting in lower costs of compliance for ratepayers Maintains flexibility of market actors to enter into unique contractual arrangements	BPU costs of developing and updating to keep pace with changing market needs

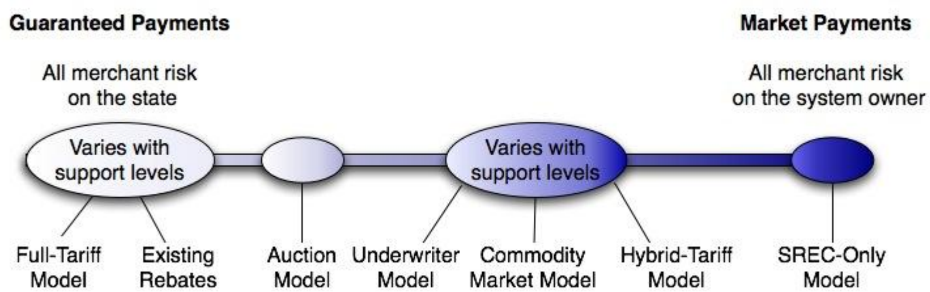
[281] Though this element was not included in any formal proposal, it is being discussed by BPU and market stakeholders as an option for avoiding having rebate-funded systems receive windfall profits in a post-rebate environment in which SREC values will likely be much higher than they are today.

5.1.6 Risk Allocation

Each of the strategies considered uses a different combination of revenue streams to try to make the economics of the installation work. In particular, the models differ in their level of dependence on, and certainty associated with SREC revenue, and correspondingly, who is carrying the various risks associated with the project.

Risk allocation is a key element of project finance. Lenders must feel 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. As a result, the level of financial risk affects overall project costs, which consumers have access to investment opportunities, and whether a sufficient level of project development will occur to achieve RPS goals. Figure 5-2 illustrates how the various potential transition strategies allocate the *merchant risk* (the risk that the value of project revenue streams may change) between the system owner and the State. As discussed earlier, there are other forms of risk to consider as well which are not represented in Figure 5-2. The placement along the risk spectrum is intended to be indicative only—the levels set for various parameters have a substantial influence on the placement along the spectrum. Note that while the commodity market model is not shown in the following figure, the risk allocation for that model would be similar to that of the underwriter model.

Figure 5-2. Risk Spectrum for Solar Market Transition Models[282]



Another important factor to consider that is not reflected in Figure 5-2 is that some models would actually *reduce* the overall level of merchant risk. For example, with the full tariff model, guaranteed payments would be made by the state at a fixed amount per kWh, and there would be no uncertainty regarding the value of those payments in terms of costs to the state or revenues to the project owners.[283] Similarly, the hybrid tariff and rebate models would reduce the overall level of merchant risk to some extent (though less than the full tariff approach) since a portion of the project investment

[282] Note that the level of risk associated with the existing rebate program varies depending on the tax appetite of the project. Corporate projects that can take advantage of the full benefits of all of the federal tax incentives have less dependence on SREC revenues to recover their investment.

[283] If the state chose a full tariff model in which tariff payments are indexed to some other market indicator (i.e. retail electricity costs), then there still would be some merchant risk associated with the model.

would be recovered through fixed payment(s) and would decrease the risk associated with an uncertain SREC revenue stream.

For the auction-set, standard contract model, the merchant risk on the project owner is low. However, one takes a risk in deciding when to invest in solar since their return on investment depends on the market clearing price that is set for the year in which their system becomes operational.

The underwriter and hybrid-tariff models are placed toward the right side of the risk spectrum since they both expose investors to substantial uncertainty regarding the SREC revenue stream. The underwriter system passes most of the merchant risk for the SRECs to the underwriting entity.

The risk allocation for the commodity market model is very similar to that of the underwriter model. Some of the merchant risk for the SREC price remains on the owner and, by extension, the lender. The smaller systems get a break with the continuation of rebates, which reduces their merchant risk. The extension of the SREC life to 2 years also reduces the merchant risk for project owners. However, the inclusion of the larger, grid-connected systems may reduce the price of SRECs and could increase the merchant risk for smaller system owners whose project economics require higher levels of SREC revenue.

The merchant risk for the SREC-only approach is entirely on the system owner. Therefore, it is placed on the far right of risk spectrum.

5.1.7 Other Factors Considered in Qualitative Assessment

In addition to qualitatively reviewing the solar market transition options according to the evaluative criteria, the team also polled stakeholders regarding their views on the market transition options, and considered how different future scenarios might affect each market transition option.

Results of the poll of market participants showed that they strongly supported moving to a market model that would maximize investor confidence, and one that would enable project development to proceed rapidly to facilitate achievement of the RPS goals. Market participants also supported selecting a model that would provide opportunities for a diverse range of consumers to participate in the market.

The review of future potential market scenarios demonstrated the importance of incorporating elements of flexibility into an incentive structure to enable it to adapt to future market conditions. For example, consider a situation in which future installed costs were to drop dramatically due to a technological breakthrough. Clearly this would be good news for the future of solar investment. However, the impact on past investments could be detrimental. Ratepayers would continue paying high incentives to participants in an underwriter or tariff model because of the long-term commitments that would have been made to the earlier, more expensive systems. A dramatic drop in technology costs would also have substantial implications for early participants under the SREC-only, hybrid-tariff, and rebate models who had invested in their systems while technology costs were still high. Since SREC prices would likely drop dramatically when new system can be built at much lower costs, this could erode the value of early participants' investments.

5.1.8 Conclusions and Recommendations from Qualitative Assessment

The New Jersey solar market is relatively new and subject to much regulatory uncertainty. This uncertainty results in less financial stability, at least in the eyes of the investment community, who may view any new system with skepticism until it has worked for several years. These conditions have led many industry and policy experts to conclude that, if the New Jersey RPS goals are to be met, efforts must be made to overcome current barriers to the execution of long-term SREC purchase contracts. If not SRECs, some other type of revenue support or guarantee needs to be offered in a sustained, orderly manner over a number of years to provide project developers and potential system owners with the confidence they need for market activity to grow substantially. The research team concurs with these viewpoints.

Aside from the SREC-only model (BPU Pilot program), which would provide no form of price certainty in the market other than a price ceiling, all of the potential market transition strategies discussed here could provide a theoretically viable means of addressing revenue uncertainty concerns if structured appropriately. The proposed alternatives would also provide other benefits to ratepayers. All of the proposals do, however, possess both strengths and weaknesses.

Through the criteria-based review of the seven market models, no one model emerged as a clear winner. However, it became clear that the strongest features could be extracted from each of the proposals and combined to develop an alternative set of refined strategies.

Based on the research team's preliminary analysis discussed in this paper, refined versions of two of the models proposed by the RPS Transition Working Group were recommended for further analysis and consideration. These two models are believed to offer market flexibility and to stimulate entrepreneurship and innovation, while still providing enough stability to appeal to investors and lenders. The two models are: 1) a hybrid-tariff model in which tariff levels would differ for small and large systems; and 2) an underwriter / rebate model in which large projects would receive assistance through an underwriter and smaller projects could receive rebates. Under both models, the level of financial support provided by the state would decline gradually over time following a pre-determined schedule. That is for new projects entering into contracts for financial assistance each year, the level of assistance would be fixed for the length of the contract with that project owner, but with each new year, the level of assistance would be decreased for new projects entering the program.

5.2 Ratepayer Impact Analysis

Presented here are the results of the ratepayer impact study that was completed by the Summit Blue team. The research team was initially tasked with assessing the ratepayer costs of seven proposed options for transitioning the solar PV portion of the CORE program from providing upfront rebates to a system that fosters market-based support for renewable energy project development. An initial draft report was completed in April, 2007. This report was presented to stakeholders at a public workshop on May 9, 2007.

The BPU's Office of Clean Energy (OCE) then developed a straw proposal, based on the initial analysis of the seven proposed transition options, which included an eight-year SACP schedule and was based on the SREC Rebate model. The Summit Blue team was tasked with modeling the ratepayer costs of OCE's straw proposal. A final report, presenting the results of both the initial analysis of the seven transition models as well as the analysis of OCE straw proposal, was completed in August, 2007.[284] Full details of this study can be found in the report.

The final report updated some of the model inputs as was necessary to model the OCE straw proposal. The report focused on only one aspect of the evaluative criteria: the uncertainty regarding the ratepayer impacts of each proposed market model. OCE subsequently modified its original Straw Proposal in response to feedback received at a series of public hearings held during June and July, 2007, and the Board approved a revised version of the straw proposal on September 12, 2007.

The ratepayer impact assessment reports completed by the Summit Blue team do not include an analysis of whether the solar set-aside requirements of New Jersey's RPS constitute cost-effective public policy. They assume the RPS policy (2.12% of annual retail electricity sales must be provided by solar by 2021) is a given, and they seek to provide an independent analysis of the potential ratepayer impacts of the proposed market models.

5.2.1 Methodology

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

During **Phase I** the model used to develop preliminary screening of market models 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 individual project installations. These incentive levels were then run through an RPI analysis. During this phase of the analysis the key input variables to the model were identified using sensitivity analysis. These key variables were the basis for the uncertainty analysis in Phase II.

During **Phase II** 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 each of the key input variables identified in Phase I, and the model was run over 1,000 times using randomly selected values from the probability distributions for each key variable. The result was a forecast distribution that showed the expected range of RPI for each of the models analyzed.

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, upfront 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.

[284] *An Analysis Of Potential Ratepayer Impact Of Alternatives For Transitioning The New Jersey Solar Market From Rebates To Market-Based Incentives,* August 6 2007, Summit Blue Consulting.

The standard inputs used are shown in the table below.

Table 5-2. Standard Inputs Used in RPI Modeling

Inputs	Project Type		
	≤10 kW Private	>10 kW Private	Public[285]
Project Distribution	40%	42%	18%
System Size (kW_{dc})	6.5	51.3	110.0
kWac	5.130	40.272	86.374
kWH/yr/kW_{dc}	1,000	1,000	1,000
Annual Energy Generation	6,535	51,303	110,031
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%

5.2.2 Results – Original Proposed Market Models

Table 5-3 presents the RPI of each model by project using the standard inputs in $/kWh. Table 5-4 presents the RPI of each model by project type in millions of dollars. Table 5-4 was calculated by multiplying the results in Table 5-3 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.

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

Table 5-3. Ratepayer Impacts for Proposed Market Models in $/kWh

Model	≤10 kW Private	>10 kW Private	Public	Weighted Average
Rebate/SREC	0.00187	0.00135	0.00095	0.00148
SREC Only	0.00226	0.00130	0.00076	0.00158
Underwriter, 15 Year	0.00189	0.00112	0.00065	0.00134
Commodity Market	0.00224	0.00141	0.00089	0.00164
Auction	0.00180	0.00090	0.00057	0.00120
15-year Full Tariff	0.00141	0.00084	0.00048	0.00100
Hybrid Tariff	0.00183	0.00109	0.00062	0.00130

Table 5-4. Total Ratepayer Impacts for Proposed Market Models ($ millions)

Model	≤10 kW Private	>10 kW Private	Public	Weighted Average
Rebate/SREC	$5,516	$3,994	$2,819	$4,385
SREC Only	$6,688	$3,830	$2,232	$4,673
Underwriter, 15 Year	$5,580	$3,316	$1,919	$3,960
Commodity Market	$6,621	$4,157	$2,627	$4,856
Auction	$5,308	$2,670	$1,694	$3,537
15-year Full Tariff	$4,158	$2,494	$1,423	$2,960
Hybrid Tariff	$5,399	$3,232	$1,840	$3,838

5.2.3 Results – OCE Straw Proposal

A revised and final version of the OCE's straw proposal was issued on August 24, following stakeholder input and the several re-runs of the RPI model with new inputs. This version was later accepted by the Board. Assumptions used in the final version include:

- Model: Competitive, Multiple Year SACP with Rebates for Smaller Projects
- Target IRR: 12%
- Qualification Life: 15 Years
- Annual percentage decrease in SREC/SACP Levels: 3%

The SREC levels required to achieve the target IRR of 12% were calculated as follows:

Table 5-5. SREC Levels Required to Achieve Target IRR

Energy Year	2009	2010	2011	2012	2013	2014	2015	2016
SREC	$611	$593	$575	$558	$541	$525	$509	$494

The OCE proposal included the proposal to set the SACP level to $100 above the SREC level. This results in the following 8 Year SACP schedule:

Table 5-6. Proposed 8-Year SACP Schedule

Energy Year	2009	2010	2011	2012	2013	2014	2015	2016
SACP	$711	$693	$675	$658	$641	$625	$609	$594

The table below shows the ratepayer impacts of the revised OCE straw proposal in terms of the annual cost of SRECS needed to meet the RPS solar set-aside, and the percentage of estimated retail electricity sales that this will represent.

Table 5-7. Total Ratepayer Impacts of the Revised Straw Proposal ($ millions)

Energy Year	2009	2013	2017*	2021*	2023*	Total cost (NPV)
Annual SREC Cost of Straw	$42.2	$210.2	$490.9	$904.7	$864.3	$3,562.8
Estimated Total Retail Sales	$10,895.2	$13,113.0	$15,782.9	$18,997.3	$20,842.5	$154,644.8
SREC cost of Straw as a % of Total Retail sales	0.39%	1.60%	3.11%	4.76%	4.15%	2.304%

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