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Via Hand Delivery

November 29, 2012

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: R.I. Office of Energy Resources' Report and Recommendations Regarding 2013 Distributed Generation Classes, Ceiling Prices and Targets (Docket No. 4288)

Dear Ms. Massaro:

I am enclosing for filing on behalf of the Rhode Island Office of Energy Resources an original and ten (10) copies of its Report and Recommendations regarding 2013 distributed generation classes, ceiling prices and targets.

We are sending electronic copies to all persons named on the attached Service List and will provide a hard copy to anyone that requests it. Please acknowledge receipt of this filing on the enclosed copy of this letter and return it with my messenger. Thank you for your cooperation.

Sincerely,

Peter V. Lacouture

PVL/blv

Enclosures

Copy to: Leo Wold, Esq. *(via hand delivery)*
Thomas R. Teehan, Esq. *(via hand delivery)*
Docket 4288 Service list *(via e-mail)*

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Docket No. 4288 – Office of Energy Resources Filings: 1) Proposed Distributed Generation (DG) Standard Contract Act Classes and Ceiling Prices for 2011; and 2) Proposed DG Standard Contract; and

Docket No. 4277 – National Grid National Grid – Distributed Generation Enrollment Application & Enrollment Process Rules

Service Lists updated 9/20/12

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File an original & 10 copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Lmassaro@puc.state.ri.us Adalessandro@puc.state.ri.us Anault@puc.state.ri.us Dshah@puc.state.ri.us Nucci@puc.state.ri.us	401-780-2107
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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

In re R.I. Office of Energy Resources' Report	:	
and Recommendations Regarding 2013 Distributed	:	Docket No. 4288
Generation Classes, Ceiling Prices and Targets	:	

Report and Recommendation
Of the Rhode Island Office of Energy Resources
On 2013 Distributed Generation Classes, Ceiling Prices, and Targets

I. INTRODUCTION

The Distributed Generation Standard Contracts Act, R.I. Gen. Laws §39-26.2-1 *et. seq.* ("Act") requires the Distributed Generation Standard Contract Board ("Board") to establish renewable energy classes, set renewable energy class targets, and propose ceiling prices for each class on an annual basis. R.I. Gen. Laws §§39-26.2-3(10), 39-26.2-4, and 39-26.2-5. Until the Board is duly constituted, the Act delegates the Board's powers and duties to the Office of Energy Resources ("OER"). R.I. Gen. Laws §39-26.2-3(3).

This is OER's Report and Recommendations for 2013 Distributed General Classes, Ceiling Prices, and Targets (Allocations). OER's 2013 program recommendations are summarized on Exhibit A attached hereto and are explained further in this report.

On September 27, 2011, OER filed an extensive Report and Recommendations regarding classes, ceiling prices and targets. The proposal, along with the standard contract required under Section 39-26.2-7 of the Act, was approved by the PUC in Order No. 20676.[1] On September 20, 2012, OER filed a motion for an extension of the October 15, 2012 deadline for the filing of its recommendations for 2013, for a period of forty-five (45) days. It also moved for relief from paragraph 6 of the 2011 Approval to permit the reallocation of the remaining target from the 2012 allocation into the 2013 program. By orders dated November 16[2] and November 21[3], the PUC granted OER's motion for extension of time and motion for relief from paragraph 6 of Order No. 20676, respectively.

II. BACKGROUND – 2012 RESULTS

The OER has been monitoring the Distributed Generation Standard Contracts ("DGSC") program over the last year, with National Grid's enrollments for the DGSC program occurring in December 2011 and April and July 2012. Through the first full year of the program (three

[1] In re: Rhode Island Office of Energy Resources' Report and Recommendations regarding Distributed Generation Classes and Ceiling Prices, R.I. Office of Energy Resources' Proposed Standard Contract, and Narragansett Electric Company d/b/a National Grid's Proposed Distributed Generation Enrollment Application and Process Rules, Docket Nos. 4288 and 4277, Report and Order (Order No. 20676, March 15, 2012) [hereinafter, "Order 20676"].
[2] In re: Rhode Island Office of Energy Resources' Motion for Extension of Time, Docket No. 4277, Order (Order No. 20880, November 16, 2012).
[3] In re: Rhode Island Office of Energy Resources' Motion for Relief from Order No. 20676 regarding the 2012 Distributed Generation Targets, Docket No. 4288, Order (Order No. 20883, November 21, 2012).

enrollments), National Grid received 30 applications, totaling over 32 MW and has selected distributed generation projects totaling 16.177 MW.

There have been sixteen projects that have executed DGSC contracts with National Grid, including two municipal based projects (City of East Providence and Town of Westerly) and fourteen private projects. There are fifteen solar projects scheduled to be built over the next year, and one wind turbine project was recently installed. National Grid received only a single wind turbine application through the three enrollments.

The OER has experienced some organizational changes since Ken Payne stepped down as Administrator in late December 2011. The future of the OER was a focus for the Administration and the General Assembly including a restructuring of the OER responsibilities and securing long-term staff funding. Following this effort, in June 2012, Governor Chafee nominated Marion Gold from the University of Rhode Island to serve as the OER Commissioner, filling a position that had remained vacant since July 2009.

Since Administrator Gold has joined the OER, her staff has worked with National Grid to provide information to stakeholders on the results of the 2011-2012 DGSC program. OER staff also have been worked on the development of classes, ceiling prices, and targets for the 2013 program. The OER hosted DGSC public meetings on August 20th, September 7th, October 18th, November 7th, 19th, and 28th. The meetings occurred at either the Department of Administration or the Economic Development Corporation. Attached as Exhibit B is a list of the individuals who attended one or more of the meetings conducted by OER. The presentations from the meetings and other information are attached as Exhibits C through I.

III. 2013 DGSC PROGRAM

A. Technology Classes and System Sizes

The objectives for the 2013 program are the following:

1. Increase the opportunities for different technologies to participate in the program.
2. Decrease, where appropriate, the technology class ceiling prices.
3. Reduce the overall program cost from the 2012 program.
4. Create a stable and predictable program.

The OER recommends the following classes and system sizes for solar, wind, and anaerobic digestion:

Small DGSC System Technologies and Sizes
Wind: 50 kW - 1.5 MW
Small Solar PV: 50-100 kW
Small Solar PV: 101-250 kW
Small Solar PV: 251-500 kW
Anaerobic Digestion: 400-500 kW

Large DGSC System Technologies and Sizes
Large Solar: 501 kW and above
Anaerobic Digestion: 501 kW and above

Solar - The OER adjusted the solar target classes to allow smaller projects, suitable for small business or municipal sites, to participate. The adjustment will diversify the sizes of solar target classes. Moreover, the recommended 2013 ceiling prices are below the ceiling prices approved by the PUC in December 2011.

Wind - In recent years, more small and medium scale wind systems (100 kW, 250 kW, 275 kW and 660 kW) have been proposed and installed in Rhode Island than large scale wind turbine systems (1.5 MW). Under the 2011 and 2012 DGSC program only one wind turbine, a 1.5 MW turbine, was proposed. No proposals for small and medium scale wind turbines were submitted. Wind energy development is the lowest cost DG technology available in Rhode Island. The OER has expanded the recommended target classes to allow eligibility of smaller DGSC wind turbine systems. The recommended adjustment will result in lower ratepayer impacts when compared to the 2012 program. This reasoning will be explained further in the OER recommended allocations.

Anaerobic Digestion - The OER has added anaerobic digestion (AD) technology to the small and large DGSC target classes. Expanding this size category beyond wind and solar may lead to reduced ratepayer impacts. Anaerobic digestion projects can occur on sites such as municipal/private waste water treatment facilities or on agricultural sites.

Hydropower - The existing DGSC law requires that any eligible renewable energy technology be fully operation within eighteen months after a DGSC contract has been signed. Discussions with hydropower developers and staff from the Rhode Island Department of Environmental Management and the U.S. Department of Energy confirm that no hydropower project could be built within eighteen months due to the extensive review and approvals required from the state and federal agencies. The OER will work with state and federal officials in 2013 to address this challenge so that hydropower projects might be able to participate in the 2014 DGSC program.

The OER recommends the proposed hydropower system size (500kW - 1 MW) and is proposing a ceiling price (below) to allow private developers and state and municipal officials to begin reviewing the economic details of potential hydropower projects for 2014. However, for the reasons explained above, there is no allocation or target proposed for hydropower in the 2013 program.

B. Recommended Ceiling Prices

The OER contracted with Sustainable Energy Advantage (SEA), which had advised on the 2011-2012 ceiling prices, to perform the analysis of the ceiling prices for the 2013 DGSC program. SEA used the Cost of Renewable Energy Spreadsheet Tool ("CREST") Model in calculating the pricing for the target classes. The CREST Model is current (May 2011) and a publicly available for use rather than proprietary; the CREST Model was published as a report of

the National Renewable Energy Laboratory, a national laboratory of the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency.

The CREST model was used to develop the recommended ceiling prices for the 2011 and 2012 DGSC program. To generate ceiling prices with the CREST Model, SEA collected data from similar renewable energy programs in Massachusetts, Connecticut, Vermont, and New York. SEA also requested from National Grid the economic data from the DGSC applications submitted in 2011 and 2012.

The proposed 2013 DGSC ceiling prices were presented on October 19th and the OER accepted public comments on the ceiling pricing. The OER hosted additional DGSC public meetings to discuss the proposed and recommended 2013 ceiling prices on November 7th and 28th.

The chart below provides the details and differences in the approved PUC ceiling prices in 2011 and 2012, and what the OER is recommending for 2013.

Technology, sub-class	**2011/2012 Ceiling Price (¢/kWh)**	**2013 Proposed Ceiling Price (¢/kWh) w/PTC**	**Change -- 2011/2012 to 2013 Ceiling Prices**	**2013 Proposed Ceiling Price (¢/kWh) w/o PTC**
Solar, 500 kW+	**28.95**	**24.95**	**-14%**	**N/A**
Solar, 251 – 499 kW	**31.60**	**28.40**	**-10%**	**N/A**
Solar, 101 – 250 kW	**33.35 (for 150 kW)**	**28.80**	**-14%**	**N/A**
Solar, 50 – 100 kW	**33.35 (for 150 kW)**	**29.95**	**-10%**	**N/A**
Wind, 1 – 1.5 MW	**13.35**	**16.80**	**26%**	**18.60**
Wind, 200 – 999 kW	**N/A**	**18.15**	**N/A**	**19.95**
Wind, 50 – 100 kW	**N/A**	**24.65**	**N/A**	**N/A**
AD, 400 – 500 kW	**N/A**	**18.55**	**N/A**	**19.55**
AD, 501 kW and above	**N/A**	**18.55**	**N/A**	**19.55**
Hydro, 500 kW – 1 MW	**N/A**	**17.90**	**N/A**	**18.85**

Solar - The OER reviewed the 2011 and 2012 ceiling prices with SEA and reduced the solar ceiling prices by 10 to 14 percent for the eligible system classes in 2013. SEA used solar data inputs from the existing renewable energy procurement programs in Connecticut, Massachusetts, Vermont, New York, and also the economic project cost data from the DGSC applications submitted in 2011 and 2012.

Wind – OER recommends an increase in the wind turbine ceiling prices for the 2013 program though the wind ceiling prices remain significantly lower than prices for solar projects The adjusted size classes will offer more flexibility in siting wind turbine systems and the revised size classes and prices may incentivize more wind turbine projects (and fewer solar projects) which would lead to reduced ratepayer impacts for 2013. This reasoning will be explained further in the OER recommended allocation plan.

Due to the uncertainty with the federal Production Tax Credit (PTC) for wind turbine projects, the OER is submitting two ceiling prices for wind; one with the PTC and the one without it. The PTC will expire on December 31, 2012.

Anaerobic Digestion - Anaerobic digestion technology and the proposed ceiling price are new to the DGSC program. The additional technology will diversify the program; reduce the allocation to solar; and reduce overall impacts on ratepayers in 2013. This reasoning will be explained further in the OER recommended allocation plan.

The OER recommends two different ceiling prices for anaerobic digestion depending on the future of the PTC incentive.

C. OER Recommended Allocation Plan

In September, OER requested that the remaining 3.8 MW from the 2012 program be rolled over into the 2013 program. As noted above, the PUC has approved this change. As a result, the program has 13.8 MW for three enrollments in 2013. The OER recommends that 9.8 MW be allocated to the small DGSC system classes and 4.0 MW to the large DGSC system classes, subject to increase as explained below, for 2013.

D. Adjustment to the Enrollment Plan

The OER hosted two public meetings on November 19th and 28th about the proposed enrollment plan and provided an opportunity for stakeholders to submit written comments. With one exception, the OER recommends that the 2013 MW allocations to the wind, solar, and anaerobic digestion classes remain in the same classes throughout the year and not be moved to other target technology classes. Thus, for example, if no small anaerobic digestion projects are proposed in the first enrollment period, the 500 kW allocation would be added to the anaerobic digestion allocation for the second period. The only exception is with respect to the 50 – 100 kW small solar PV: if the 300 kW allocation were not used in one or more allocation periods, the unused portion of the allocation from that enrollment would be added to the large DGSC class for that and future periods. National Grid would be allowed to utilize the unused portion of the 300 kW solar target class from each enrollment (900 kW potentially available from the three rounds) to the large DGSC target classes.

The OER has the following reasons for these recommended changes:

1. The changes will create a stable and predictable program for businesses, municipalities, and renewable energy developers. The predictability is important particularly in light of the interconnection studies that are prerequisites for a DGSC application.

2. Wind turbine and anaerobic digestion projects typically have longer permitting and siting timelines and should not be compared to the process for a solar project installation.

3. Adjustment in wind turbine system sizes will allow for more appropriately sited wind projects to developed and to gain town and city approval. By not having the wind allocation automatically rolled into the solar target classes, wind projects will not need to be rushed into submitting a DGSC application to get into a scheduled enrollment.

4. Reduced impacts on ratepayers over the lifetime of the DGSC contracts, by not having the wind and anaerobic digestions MW allocations automatically going toward the solar classes.

The OER recommends the following allocations be approved for each of the three (3) enrollments in 2013. Any remaining allocations at the end of the year would be rolled over and utilized in the 2014 DGSC program.

Small DGSC Enrollment Program	
Technology & Class	**kW/MW Allocation**
Wind: 50 kW - 1.5 MW	1.5 MW
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	250 kW
Small Solar PV: 251-500 kW	750 kW
Anaerobic Digestion 400–500 kW	500 kW
Large DGSC Enrollment Program	
Solar PV/Anaerobic Digestion: 501 kW and above	1.3 MW[4]
Total MW	**4.6 MW**

There would be 1.3 MW or more available for the large DGSC program for each enrollment in 2013. The OER has omitted a wind turbine class from the large DGSC allocation.

The OER believes that under its proposed adjustments to the eligible small DGSC wind turbine classes and recommended enrollment plan for 2013, that there will be a number of opportunities for appropriately sited wind turbine projects to participate in the program.

[4] Subject to increase, as explained above.

E. Stable Program

The OER will work with National Grid to schedule three (3) enrollment periods for 2013, to provide for a predictable program.

IV. CONCLUSION

Following review of the results of the 2011-2012 program, additional work by its consultant, SEA, extensive input from the various stakeholders, and multiple public meetings, OER has developed revised classes, ceiling prices, and targets for the 2013 DGSC program. OER respectfully requests that the PUC approve the proposed classes, ceiling prices, and targets.

List of Exhibits to OER Report (November 29, 2012)

A. Summary of OER Recommended Classes, Ceiling Prices and Targets

B. List of attendees at OER public meetings

C. Office of Energy Resources Power Point Presentation - 40 Megawatt Distributed Generation Standard Contracts Program: Results & Next Steps (August 20, 2012)

D. Office of Energy Resources Power Point Presentation – 2012 and 2013 Distributed Generation Contracts Program – Updates and Next Steps (September 7, 2012)

E. Sustainable Energy Advantages – Ceiling Prices Questionnaire/Survey for 2013 DGSC Program (September, 2012)

F. Sustainable Energy Advantages – Input and Assumptions for Ceiling Prices for 2013 DGSC Program – 1st Power Point Presentation (October, 2012)

G. Sustainable Energy Advantages – Input and Assumptions for Ceiling Prices for 2013 DGSC Program – 2nd Power Point Presentation (November 7, 2012)

H. Office of Energy Resources Power Point Presentation - 2013 Distributed Generation Contracts Program – Update and Proposed 2013 Megawatt Allocation Plan (November 19, 2012)

I. Office of Energy Resources Power Point Presentation – 2013 Distributed Generation Contracts Program – Recommended Ceiling Prices, Target Classes, and Enrollment Plan (November 28, 2012)

EXHIBIT A

Rhode Island Office of Energy Resources
Recommended Target Classes, Ceiling Prices, and Targets (Allocations) for the
2013 Distributed Generation Standard Contracts Program

OER recommends that National Grid conduct three (3) enrollments in 2013 and award 4.6 MW of projects in each enrollment, for a total of 13.8 MW of Distributed Generation projects in 2013.

Recommended Technology Classes and Targets (Allocations)

Small DGSC Enrollment Program

Technology & Class	Allocation (kW/MW)
Wind: 50 kW - 1.5 MW	1.5 MW
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	250 kW
Small Solar PV: 251-500 kW	750 kW
Anaerobic Digestion: 400–500 kW	500 kW

Large DGSC Enrollment Program

Large Solar PV: 501 kW and above and Anaerobic Digestion: 501 kW and above	1.3 MW total[5] (for 2 technologies)
Total MW	**4.6 MW**

Recommended Ceiling Prices (¢/kWh), by Technology Class

Technology, sub-class	2013 Proposed Ceiling Price w/PTC	2013 Proposed Ceiling Price w/o PTC
Solar, 501 kW+	24.95	N/A
Solar, 251 – 500 kW	28.40	N/A
Solar, 101 – 250 kW	28.80	N/A
Solar, 50 – 100 kW	29.95	N/A
Wind, 1 – 1.5 MW	16.80	18.60
Wind, 200 – 999 kW	18.15	19.95
Wind, 50 – 100 kW	24.65	N/A
AD, 400 kW – 500 kW	18.55	19.55
AD, 501 kW and above	18.55	19.55
Hydro, 500 kW – 1 MW	17.90	18.85

[5] Subject to increase as explained in OER's Report of November 29, 2012.

EXHIBIT B

The following individuals attended one or more of OER's DSGC public meetings:

- Marion Gold – Office of Energy Resources
- Chris Kearns – Office of Energy Resources
- Charlie Hawkins – Office of Energy Resources
- Ken Payne – Systems Aesthetics LLC
- Julian Dash – Clean Energy Economy
- Ian Springsteel – National Grid
- Jerry Elmer – Conservation Law Foundation
- Jon Hagopian – Division of Public Utilities and Carriers
- Bob Grace – Sustainable Energy Advantages
- Jason Gifford - Sustainable Energy Advantages
- Bill Ferguson – The Energy Council of Rhode Island
- Seth Handy – Handy Law LLC
- Stephen Wollenberg – People's Power and Light
- Karina Lutz – Consultant, People's Power and Light
- Tim Hetland – Rhode Island Wind Power LLC.
- Vito Buomono – Rhode Island Wind and Solar LLC.
- Scott Milnes – Beaumont Solar
- Frank Epps – Rterra Renewables
- Dan Richardson – Rterra Renewables
- Bob Chew – RChew Energy Consulting
- Michelle Mulchay – Sustainable Energy Solutions
- Fred Unger – Heartwood Associates
- Eric Offenberg – Diprete Engineering
- Nils Behn – Aegis Wind
- Tim Faulkner – ECO RI
- Jeff Broadhead – Washington County Regional Planning Council
- Dennis McCarthy - Solect Energy Development
- Tony Callendrello – NEO Energy
- Larry Dressler – Tomorrow Biofuels
- Dennis Duffy - Energy Management, Inc
- Jaime Fordyce – Energy Management, Inc
- Mitchell Jacobs – Energy Management, Inc
- Hunter Straiter – NEXAMP
- Palmer Moore - NEXAMP
- Alan Clapp - Woodard & Curran
- Peter Lacouture - Robinson & Cole LLP (OER counsel)
- Charity Pennock – New England Clean Energy Council
- Robert Tormey NERC Solar
- Barry Wenskowicz – Narragansett Bay Commission

EXHIBIT A

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2013 Distributed Generation Standard Contracts Program

OER recommends that National Grid conduct three (3) enrollments in 2013 and award 4.6 MW of projects in each enrollment, for a total of 13.8 MW of Distributed Generation projects in 2013.

Recommended Technology Classes and Targets (Allocations)

Small DGSC Enrollment Program

Technology & Class	Allocation (kW/MW)
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Anaerobic Digestion: 400–500 kW	500 kW

Large DGSC Enrollment Program

Large Solar PV: 501 kW and above and Anaerobic Digestion: 501 kW and above	1.3 MW total[5] (for 2 technologies)
Total MW	**4.6 MW**

Recommended Ceiling Prices (¢/kWh), by Technology Class

Technology, sub-class	2013 Proposed Ceiling Price w/PTC	2013 Proposed Ceiling Price w/o PTC
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[5] Subject to increase as explained in OER's Report of November 29, 2012.

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- Bob Grace – Sustainable Energy Advantages
- Jason Gifford - Sustainable Energy Advantages
- Bill Ferguson – The Energy Council of Rhode Island
- Seth Handy – Handy Law LLC
- Stephen Wollenberg – People's Power and Light
- Karina Lutz – Consultant, People's Power and Light
- Tim Hetland – Rhode Island Wind Power LLC.
- Vito Buomono – Rhode Island Wind and Solar LLC.
- Scott Milnes – Beaumont Solar
- Frank Epps – Rterra Renewables
- Dan Richardson – Rterra Renewables
- Bob Chew – RChew Energy Consulting
- Michelle Mulchay – Sustainable Energy Solutions
- Fred Unger – Heartwood Associates
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- Tim Faulkner – ECO RI
- Jeff Broadhead – Washington County Regional Planning Council
- Dennis McCarthy - Solect Energy Development
- Tony Callendrello – NEO Energy
- Larry Dressler – Tomorrow Biofuels
- Dennis Duffy - Energy Management, Inc
- Jaime Fordyce – Energy Management, Inc
- Mitchell Jacobs – Energy Management, Inc
- Hunter Straiter – NEXAMP
- Palmer Moore - NEXAMP
- Alan Clapp - Woodard & Curran
- Peter Lacouture - Robinson & Cole LLP (OER counsel)
- Charity Pennock – New England Clean Energy Council
- Robert Tormey NERC Solar
- Barry Wenskowicz – Narragansett Bay Commission

40 Megawatt Distributed Generation Contracts Program – Results & Next Steps

Office of Energy Resources

August 20, 2012

2011 and 2012 Results

- 5 megawatts allocated in December 2011.
- 5 megawatts allocated in April 2012.
- 5 megawatts allocated in July 2012. Notifications of applicants selected will occur soon.
- Additional megawatts will be allocated in October.
- Through the first three rounds of the DGC program, a total of 38.88 megawatts of applications have been received.

Approved 2011 and 2012 Ceiling Prices

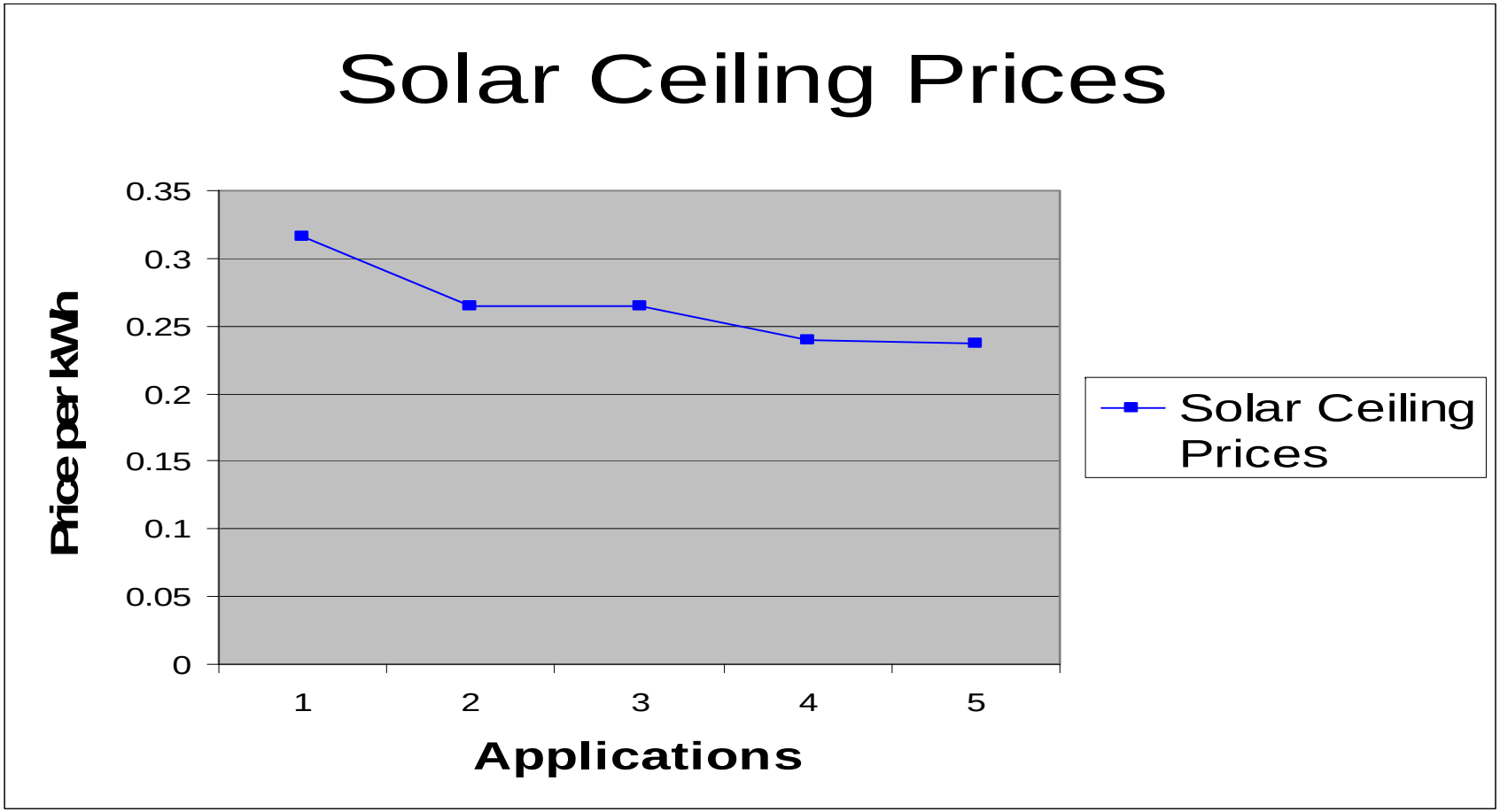
Class Nameplate	Target Capacity for Class	Ceiling Price (cents/kWh)
PV (10-150 kW)	0.5 MW	33.35
PV (151-500 kW)	1.0 MW	31.60
PV (501-5000 kW)	2.0 MW	28.95
Wind (1.5 MW)	1.5 MW	13.35

First 2 Rounds of the DGC Program

- 6 projects awarded contracts from the first two rounds. Projects included:
- 1.5 MW wind turbine project in North Kingstown.
- 500 kilowatt solar project in Middletown.
- 1 MW solar project in Westerly (Municipal).
- 2 MW solar project in West Greenwich.
- 2.34 MW solar project in North Kingstown.
- 3.71 MW solar project in East Providence (Municipal).

DGC Ceiling Prices for Projects Approved

- 0.1335 cents per kWh for Wind
- 0.316 cents per kWh for Medium Solar
- 0.265 cents per kWh for Large Solar
- 0.265 cents per kWh for Large Solar
- 0.23699 cents per kWh for Large Solar
- 0.239 cents per kWh for Large Solar



These are the prices through the first two rounds of the DGC program.

Only 1 wind turbine project has been submitted for a DGC contract in the first three rounds of the program.

Next Steps

- The 2013 DGC program will allocate 10 megawatts for renewable energy projects.
- There will be three standard contract enrollments during the program year.
- Any adjustments in the ceiling prices or megawatt carve outs need to be submitted to the Public Utility Commission by October 15th.

Comments/Questions

Contact Information

Chris Kearns
Programming Services Officer
christopher.kearns@energy.ri.gov
401-574-9113

2012 and 2013 Distributed Generation Contracts Program – Updates and Next Steps

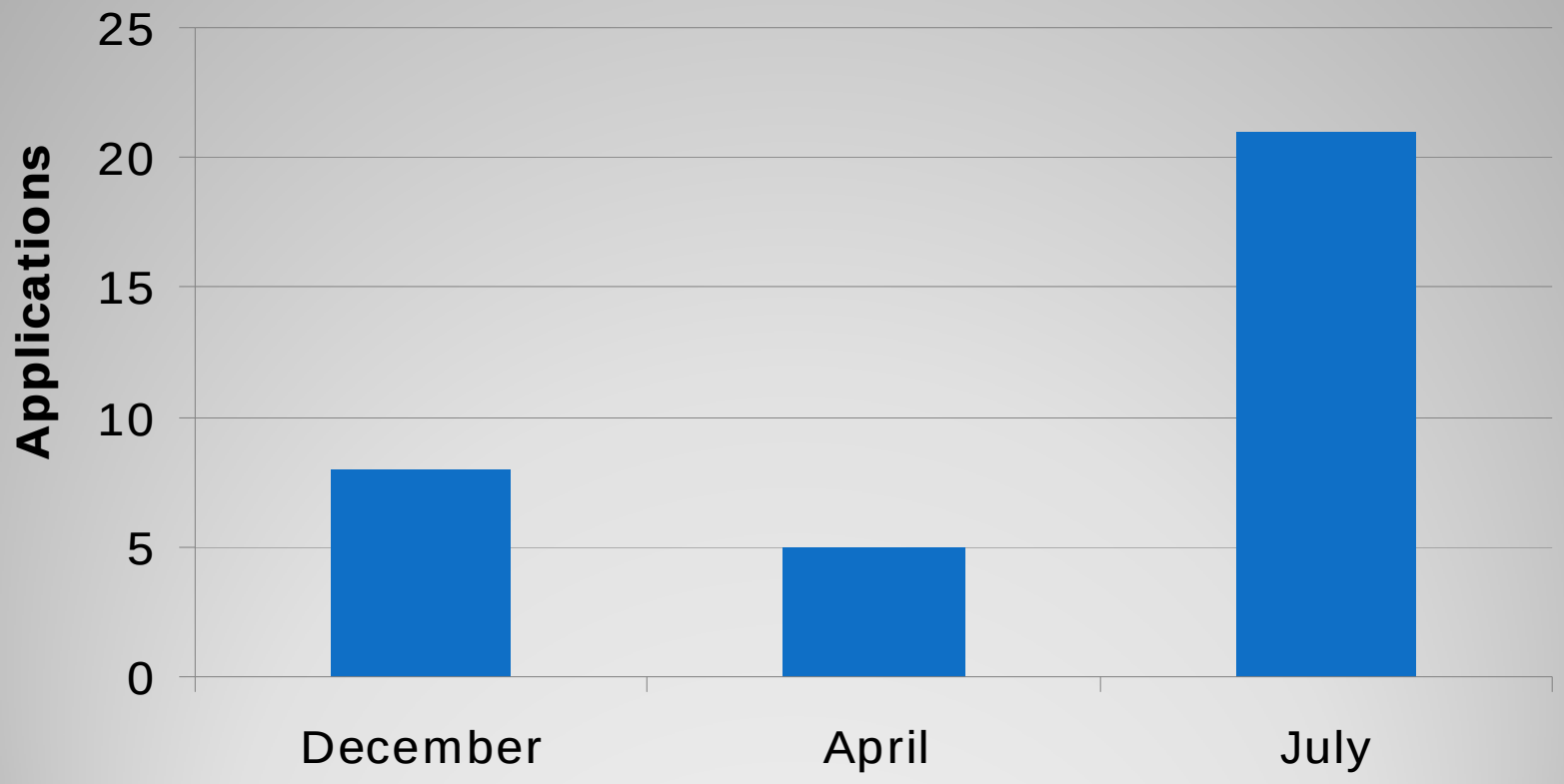
Office of Energy Resources
Marion Gold, Administrator
September 7, 2012

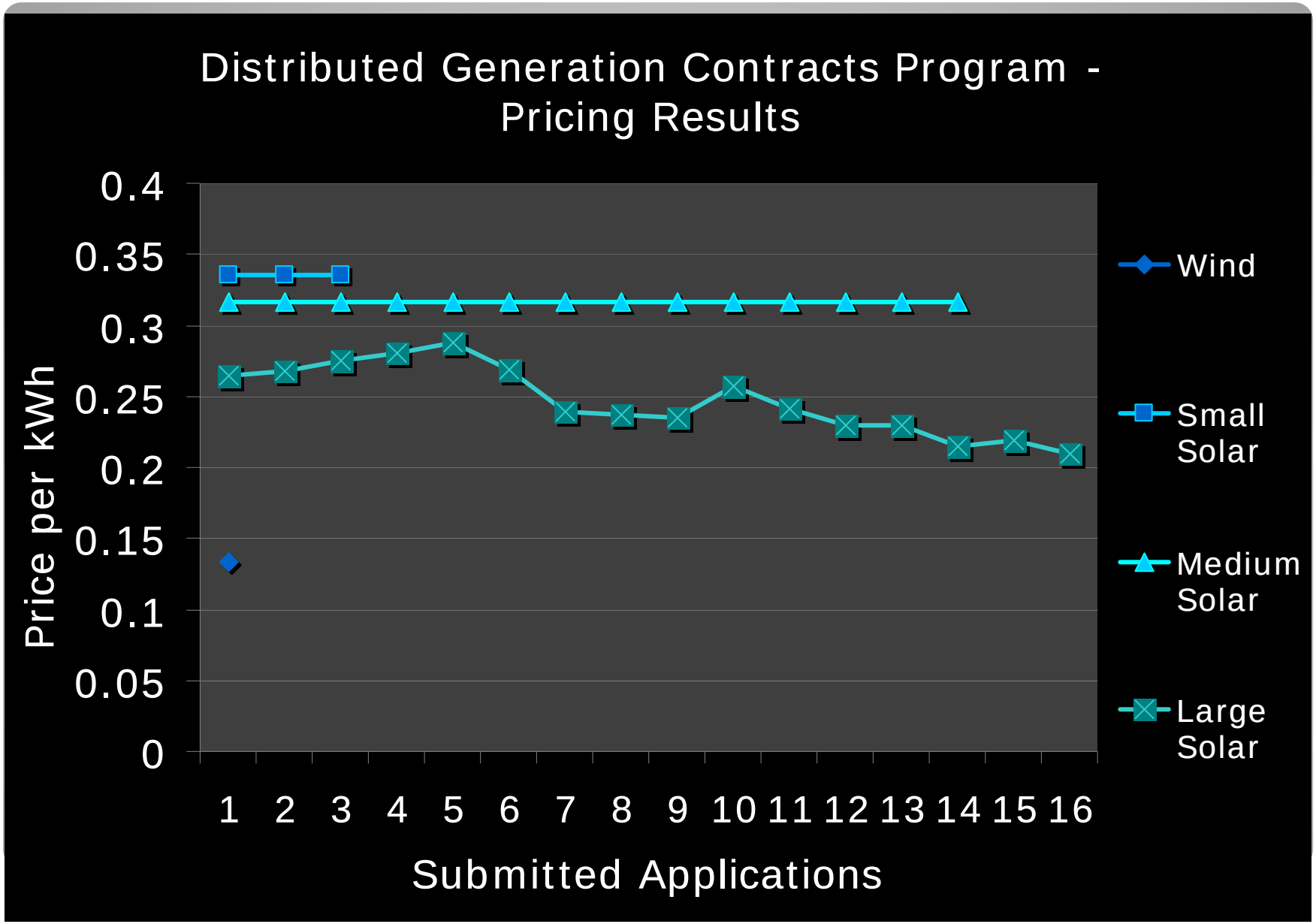
First 3 Rounds of the Program

- 16 projects awarded Distributed Generation (DG) contracts.
- 1 award for a wind turbine project.
- 10 awards for small/medium scale solar projects.
- 5 awards for large scale solar projects.

Renewable Energy Technology	System Size	Price per kWh
Wind Turbine	1.5 MW	0.1335
Small Solar	149 kW	0.335
Medium Solar	181 kW	0.316
Medium Solar	499 kW	0.316
Medium Solar	500 kW	0.316
Medium Solar	500 kW	0.316
Medium Solar	320 kW	0.316
Medium Solar	500 kW	0.316
Medium Solar	500 kW	0.316
Medium Solar	500 kW	0.316
Medium Solar	498 kW	0.316
Large Solar	1 MW	0.265
Large Solar	2 MW	0.275
Large Solar	2.34 MW	0.23699
Large Solar	3.71 MW	0.239
Large Solar	1.5 MW	0.209

Application Response




Distributed Generation Contracts Program - Pricing Results
Price per kWh
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16
Submitted Applications
Wind
Small Solar
Medium Solar
Large Solar

Projects Across the State

- DG applications have been submitted in the following cities and towns in the first three (3) rounds of the program:

- Central Falls, Westerly, West Warwick, Providence, East Providence, Portsmouth, Lincoln, Cumberland, Hopkinton, Middletown, North Kingstown, North Smithfield, East Greenwich, West Greenwich, and Bristol.

Ceiling Prices - Next Steps

- Review the large solar ceiling price. Ultimately, the market will dictate what the minimum ceiling price needs to be for projects to be built.
- Provide two-three ceiling prices for the small/medium (100-500 kW) scale solar sizes, due to the limitations within the existing DG law.
- Provide three (3) ceiling prices for different scale wind turbines. (100kW, 500kW-1MW, 1.5 MW). This will allow for appropriately sited projects with sufficient wind resources to participate in the program.
- Explore ceiling prices with and without the federal production tax credit (PTC) for wind turbine projects. The PTC expires in December 2012.
- Provide a ceiling price for hydropower. (1MW or greater)
- Provide a ceiling price for anaerobic digestion.

Potential 2013 MW Allocation Plan

Technology	MW Carve Out	Ceiling Prices
Wind	1.5 MW	TBD
Large Solar	2.2 MW	TBD
Small/Medium Solar	1 MW	TBD
Anaerobic Digestion	300 kW	TBD

Potential 2013 MW Allocation Plan

Technology	MW Carve Out	Ceiling Prices
Large Solar	3.0 MW	TBD
Small/Medium Solar	1.5 MW	TBD
Anaerobic Digestion	500 kW	TBD

If no wind turbine applications are submitted in any of the three (3) rounds of the 2013 DG program, than this would be the potential MW allocation plan.

Hydropower

- There is no MW carve out for hydropower in the 2013 program.
- The Office of Energy Resources (OER) believes that there are no current hydropower projects that can be completed within the 18 month deadline established within the DG law.
- The Federal Energy Regulatory Commission (FERC) estimates that the state/federal permitting process currently takes between 24-48 months.
- The OER wants to establish a hydropower price to allow developers, municipalities, and the Public Utility Commission (PUC) to get an understanding of what the ceiling price would be for hydropower projects.
- Having an approved PUC ceiling price in 2013, could potentially allow developers and municipalities to be prepared for the 2014 DG program.

Next Steps

- The OER will respectfully request that the PUC and National Grid hold the remaining 5 MW in the 2012 allocation plan, and use them in the 2013 program.
- Allow the ceiling prices for small/medium scale solar to be reviewed and adjusted for the different size systems, in order to reduce impacts on ratepayers.
- This OER recommendation will allow the 2013 program to have three (3) 5 MW allocations, instead of having only 3.33 MW for each allocation period.
- The OER will also respectfully request a 3-4 week extension with the PUC to submit the recommended ceiling prices and MW carve-outs for the 2013 DG program.
- The OER will host a community review meeting in late September to discuss the proposed ceiling prices and receive feedback.

Rhode Island Office of Energy Resources

CALL FOR CEILING PRICE DATA

DUE DATE FOR SUBMISSION: TUESDAY, October 2, 2012

Submit electronically to both: Christopher.Kearns@energy.ri.gov and jgifford@seadvantage.com

Dear Colleagues and Distributed Generation Contract Program Stakeholders:

As we described by e-mail of last Friday, OER has commenced work on reviewing the ceiling prices and eligible technologies for the 2013 DG Contracts program and intends for stakeholders to play an integral role by providing data and comments in response to both written requests and public meetings. **The purpose of this memo is to request your specific input and feedback regarding modeling assumptions which support the ceiling price analysis.** This is the first in a multi-step process, as follows:

(1) Collect data from stakeholders and other sources,
(2) Develop proposed ceiling prices and request stakeholder comments, including a Public Meeting,
(3) Revise proposed ceiling prices and conduct a second Public Meeting, and
(4) Submit recommended ceiling prices to the PUC.

This process needs to be completed on a very short timeline. Even if we assume that the 45-day extension request is granted by the Public Utilities Commission, we must complete this research phase, collect stakeholder feedback, conduct two public meetings, finalize ceiling prices and submit our recommendation to the PUC by mid-November. Your active participation in developing the inputs to the CREST model is critical to achieving a robust process, and submitting ceiling price recommendations on schedule.

As in 2011, we will be using the National Renewable Energy Laboratory's Cost of Renewable Energy Spreadsheet Tool[1] (CREST) in order to model our recommendations for submission to the Public Utilities Commission. To provide expert support for this effort the OER has again retained Sustainable Energy Advantage (along with their subcontractor Meister Consulting Group), the same firms that assisted in setting 2011 and 2012 ceiling prices.

Technology- and Capacity-Based Ceiling Prices

For the 2013 DG Contract Program solicitations, we propose to expand the range of eligible technologies to include anaerobic digestion, and to further parse the ceiling prices for solar and wind technologies based on different project sizes. In addition to 4 solar, 3 wind and 1 anaerobic digestion category, this process will propose a ceiling price for small hydroelectric facilities to be used as a benchmark in subsequent DG solicitations and policy discussions. While the rates are envisioned to be

[1] The CREST models and their supporting documentation can be downloaded from the NREL website: http://financere.nrel.gov/finance/content/CREST-model.

available to the full range of project sizes allowed under the Act, one standard installation will be modeled for each size range for the purpose of informing the ceiling rates for that class. The proposed 2012 ceiling price categories are presented in the following table:

Technology, sub class	Eligible Size Range	Standard Size for Modeling Ceiling Price
Solar, MW-Scale	> 500 kW	1.5 MW
Solar, Medium	251 – 500 kW	500 kW
Solar, Medium	101 – 250 kW	250 kW
Solar, Small	50 – 100 kW	100 kW
Wind, Large	> 1.0 MW – 1.5 MW	1.5 MW
Wind, Medium	101 kW – 1.0 MW	1.0 MW
Wind, Small	90 – 100 kW	100 kW
Anaerobic Digestion	250 – 500 kW	500 kW
Hydroelectric	500 kW – 1.0 MW	1.0 MW

We invite you to offer recommendations for data inputs that we should include in each model, using the format in the attached data request. When making recommendations, keep in mind that we are seeking ceiling prices that achieve the law's goals – namely to "support and encourage development of distributed renewable energy generation systems" in a manner that is "cost effective", and provides an adequate rate of return to private investors.

A list of the inputs sought is included in the tables below. There is one table for each technology and standard size class. Please fill out as much information as you feel qualified to provide. In addition to the column for Recommended Input, there are additional columns to elaborate on your recommendation and to note the source for the data provided. Please let us know if your data is based on your own expert opinion, or on specific sources of published (or unpublished) data. To ensure that we meet our deadlines, we ask that you **submit your recommended inputs no later than next Tuesday October 2, 2012.** Please contact Jason Gifford at (802) 846-7627 or jgifford@seadvantage.com with any questions or clarifications that would help you fulfill this data request more easily and completely.

Once we have received all recommendations, conducted additional research and interviews and considered other available data sources, we will calculate our recommended ceiling prices and distribute the recommendations (and underlying assumptions) for your review and written comment. We appreciate your active participation and look forward to fulfilling the requirements of this aggressive schedule in a cooperative manner.

Best Regards,

Marion Gold & Chris Kearns

Office of Energy Resources

Data Request:

CREST is a levelized cost of energy (LCOE) model. It converts input for capital costs, fixed and variable maintenance, system performance characteristics, capital structure, and Federal and State incentives into the revenue stream required to provide a specified return to investors over a defined period of time. For the purpose of establishing ceiling prices, we propose to assume that the subject projects are owned by private sector investors who fully utilize tax incentives, when available[2]. Furthermore, while the Standard Contract will be available for excess generation from customer-sited generators located behind the retail meter, the ceiling prices will be based on a project interconnected to the utility side of the retail meter.

The following tables represent the key inputs for which we seek your recommendations. Please fill out the tables below as completely, and in as much detail, as your expertise allows. Short definitions of each of the inputs follow the tables. We ask that you review these definitions before completing the tables, as it is important that we are able to consider recommended inputs on an apples-to-apples basis. (For example, parties may aggregate operations and maintenance (O&M) costs differently. Please conform your cost information to our line items in order for the information you provide to be of greatest utility in calculating ceiling prices). Feel free to leave blank any spaces for which you have no data to offer. Please provide sources for all recommended inputs. **Please remember that these input data and the resulting ceiling prices are intended to apply to projects coming on-line in a specific window of opportunity – namely, within 18 months of being selected via one of the 2013 DG Standard Contract solicitations.**

We expect that as a result of this process, certain inputs will change from the 2011 analysis based on changes in market conditions. There may be other inputs, however, which do not warrant adjustment, and whose magnitude and rationale was the product of detailed stakeholder discussion in 2011. For these inputs – which are clearly noted below – we propose that the values remain the same unless compelling evidence for change is presented and supported.

[2] The assumed availability of federal incentives will be differentiated by technology. All solar ceiling prices will assume availability and utilization of the Investment Tax Credit (ITC). Small wind (100 kW) will likewise assume availability and utilization of the ITC, while medium and large wind ceiling prices will be calculated both with and without the availability of the Production Tax Credit (PTC). The anaerobic digester ceiling price will assume availability and utilization of the ITC, and the initial hydro ceiling price benchmark will be calculated without the PTC.

Technology Category: Solar > 500 kW Standard Project Size for calculating ceiling price: 1500 kW DC			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)	Based on stakeholder feedback and discussion in 2011, the assumed inverter efficiency is 95.5% and assumed net CF[3] is **14.65% DC.**[4]		
DC to AC Inverter Efficiency (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW$_{DC}$-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[5])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[3] Including inverter efficiency and all other sources of loss

[4] Stakeholders wishing to comment on the continued use of this assumption may to do in the Other Comments box. All suggestions provided in this field should be specific and must include associated justification.

[5] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Solar 251 – 500 kW Standard Project Size for calculating ceiling price: 500 kW DC			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)	Based on stakeholder feedback and discussion in 2011, the assumed inverter efficiency is 95.0% and assumed net CF[6] is **14.56% DC.**[7]		
DC to AC Inverter Efficiency (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW$_{DC}$-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[8])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[6] Including inverter efficiency and all other sources of loss

[7] Stakeholders wishing to comment on the continued use of this assumption may to do in the Other Comments box at the bottom of the table. All suggestions provided in this field should be specific and must include associated justification.

[8] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Solar 101 – 250 KW Standard Project Size for calculating ceiling price: 250 kW DC			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)	The 150 kW category from the 2011 analysis has been replaced by two categories: 250 kW and 100 kW. For both, we propose to use the efficiency and CF assumptions selected for the 150 kW category in 2011. The assumed inverter efficiency is 95.0% and assumed net CF is **14.39% DC.**		
DC to AC Inverter Efficiency (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW$_{DC}$-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[9])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[9] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Solar 50 – 100 kW Standard Project Size for calculating ceiling price: 100 kW DC			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)	The 150 kW category from the 2011 analysis has been replaced by two categories: 250 kW and 100 kW. For both, we propose to use the efficiency and CF assumptions selected for the 150 kW category in 2011. The assumed inverter efficiency is 95.0% and assumed net CF is **14.39% DC.**		
DC to AC Inverter Efficiency (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW$_{DC}$-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[10])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[10] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Wind > 1 MW Standard Project Size for calculating ceiling price: 1.5 MW			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)	**25%**. Based on 2011 stakeholder feedback and dialogue. We propose that this value remain unchanged for the 2012 analysis.		
Annual Production Degradation (%)			
Total installed cost ($/kW), excl. Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[11])			
Length of construction period (mos)			
See request on next page for wind financing assumptions <u>with and without</u> PTC.			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[11] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Wind > 1 MW Standard Project Size for calculating ceiling price: 1.5 MW			
Financing Assumptions With PTC			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Financing Assumptions Without PTC			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			

Technology Category: Wind 101 kW – 1.0 MW Standard Project Size for calculating ceiling price: 1.0 MW			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW), excl. Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[12])			
Length of construction period (mos)			
See request on next page for wind financing assumptions <u>with and without</u> PTC.			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[12] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Wind 101 kW – 1 MW Standard Project Size for calculating ceiling price: 1.0 MW			
Financing Assumptions With PTC			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Financing Assumptions Without PTC			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			

Technology Category: Wind 90 – 100 kW Standard Project Size for calculating ceiling price: 100 kW			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW), excl. Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below)			
Variable O&M (¢/kWh), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[13])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[13] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Anaerobic Digestion 250 – 500 kW Standard Project Size for calculating ceiling price: 500 kW			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Biogas consumption/day (cubic ft/day)			
Energy content/cubic foot (BTU/cubic ft)			
Heat Rate (BTU/kWh)			
Availability Factor			
Station Service			
Annual Production Degradation (%)			
Total installed cost ($/kW), excl. Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below)			
Variable O&M (¢/kWh), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[14])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? How much?			
Tipping Fees/Digestate Rev, if applicable: $/ton, and tons per year			
Other Comments:			

[14] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Technology Category: Hydroelectric[15] 500 kW – 1 MW Standard Project Size for calculating ceiling price: 1 MW			
Input category	**Recommended Input**	**Notes on Assumptions**	**Source**
Expected Annual Average Net capacity factor, (%)			
Annual Production Degradation (%)			
Total installed cost ($/kW), excl. Interconnection Cost			
Typical Interconnection cost ($)			
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below)			
Variable O&M (¢/kWh), Yr 1 (excluding those listed below)			
Insurance, Yr 1, (provide as % of total project cost, or in $/yr)			
Project Management, Yr 1 ($/yr)			
Land Lease, Yr 1 ($/yr)			
Annual average escalation rate for O&M expenses (%)			
Royalties (% of revenue, or $/yr)			
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described[16])			
Length of construction period (mos)			
Source (D/E) and cost (e.g. interest rate) of construction financing			
Permanent debt/equity (D/E) ratio			
Permanent debt tenor (yrs)			
Interest rate on debt (%)			
Lender's fee (% of loan amt)			
Avg. Debt Service Coverage Ratio			
After-tax target equity IRR (%)			
Decommissioning Reserve? If yes, how much?			
Other Comments:			

[15] To be eligible for the DG contracts program, hydro facilities must meet the RI RES eligibility criteria established in CRIR 90-060-015 Rules and Regulations Governing the Implementation of a Renewable Energy Standard.

[16] The methodology, assumptions and calculation of annual property tax estimates can be provided separately.

Net capacity factor (NCF), Year 1 (%) - Capacity Factor is the % representation of the actual annual production vs. the theoretical maximum annual production of an energy project. This model requires the input of a Net Capacity Factor, meaning that the estimate of actual energy production should take into account all electricity losses (including those incurred between the generating facility and the contract delivery point), scheduled and unscheduled maintenance, shading, forced outages, and any other factors that could reduce production. For a wind plant, this number should reflect the average annual P50 estimate. Note, this model assumes an AC capacity factor. Therefore, for solar PV, the net capacity factor is calculated by converting DC capacity to AC capacity (if applicable) and then applying the following formula:

net capacity .c.f. = expected annual kWh sales/(kW_{AC} x 8760 hours)

Total installed cost: This includes the total expected all-in installed project cost, which should include all hardware, balance of plant, design, construction, permitting, development (including developer fee), interest during construction and financing costs. This figure should not account for any tax incentives, grants, or other cash incentives, which will be accounted for separately. It should also exclude the assumed interconnection cost, which is specified separately.

Interconnection cost: Please include your assumptions about the "typical" interconnection cost for a system in Rhode Island. Interconnection costs include costs relating to connecting to the grid, such as the construction of transmission lines, permitting costs with the utility, and start-up costs. This category will also include the cost of a new substation, if necessary.

O&M expenses: Operations and maintenance includes all fixed and variable expenses associated with project operations. Annual expenses for insurance, property taxes, land leases, royalties, and project management should be itemized separately.

Length of construction period: The # of months from construction start to commercial operation.

Source and cost of construction financing: This indicated whether construction is funded with debt, equity or a combination thereof, and at what interest rate or target IRR.

Permanent Debt-to-equity ratio. This specifies the ratio of the portion of funds borrowed (as a percentage of the total hard costs) to the portion of project funds supplied as equity. This is typically expressed as Debt / Equity – i.e. 70/30 or 50/50, etc.

Debt tenor: This is the number of years in the debt repayment schedule. It is also referred to as debt "term."

Interest rate: The all-in interest rate is the financing rate provided by the bank or other debt investor.

Lender's Fee: This is the fee taken by the bank for originating the loan. It is expressed as a percentage of the total amount borrowed.

Debt Service Coverage Ratio: Denotes the requirement for cash flow available for debt service to be larger than the annual debt obligation itself. It is typically expressed as a ration of EBITDA (operating income) to annual debt service obligation. This survey requests the average DSCR required by the lender during the term of the loan.

Return on equity: This is the minimum after-tax internal rate of return required to attract equity investment to a project of the indicated scale, with the indicated D/E ratio.

Decommissioning Reserve: Represents the potential need to encumber cash flows from operations in order to demonstrate the availability of funds sufficient to pay for the removal of equipment from the project site at the conclusion of the facility's useful life.

Rhode Island Distributed Generation Standard Offer:

Preliminary Input Assumptions & Modeling Results for 2013 Ceiling Price Review

October 2012

Sustainable Energy Advantage, LLC
(with support from Meister Consultants Group)

2013 Ceiling Prices to be established for 9 Classes…

- 4 Solar
- 3 Wind
- 1 Anaerobic Digestion
- 1 Hydro benchmark (*not official CP for 2013*), to be included for 2nd Public Meeting
- 'standard' installations will be modeled to inform setting of ceiling rates for each class

Technology, sub class	Eligible Size Range	Standard Size for Modeling Ceiling Price
Solar, Large	500 kW and above	1.5 MW
Solar, Medium 2	251 – 499 kW	500 kW
Solar, Medium 1	101 – 250 kW	250 kW
Solar, Small	50 – 100 kW	100 kW
Wind, Large	1.0 MW – 1.5 MW	1.5 MW
Wind, Medium	400 kW – 999 kW	750 kW
Wind, Small	90 – 100 kW	100 kW
Anaerobic Digestion	400 – 500 kW	500 kW
Hydroelectric	500 kW – 1.0 MW	1.0 MW

SOLAR

Capital Cost, Installed: Details, Sources

(Includes soft costs & construction financing; excludes Interconnection)

- Industry Databases Polled

  Usable data extracted from:

  – MA SREC Database [installed cost data analyzed from projects installed within the last 3, 6, and 9 months]

  – NREL July 2012 distributed generation cost estimates

  Database reviewed; data of limited direct usefulness, from:

  – NYSERDA PowerClerks Database (Only systems <100 kW; access to raw data not available)

  – California Solar Initiative Database (Data concerns, inconsistency with more relevant databases)

  – Mass CEC Commonwealth Solar Database (Not updated since 3/12; likely redundant with SREC Database)

  – Delaware SREC Long-term Contract Auction Results (No installed cost data available, only auction results)

  – New Jersey EDC Long-term Contract Auction Results (No installed cost data available, only auction results, last auction was in 2011)

- Stakeholder Data Request

  – Responses received from stakeholders: solar (10), wind (7), anaerobic digestion (4) and hydro (5)

- Follow up Interviews; Data available to SEA through other recent engagements

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

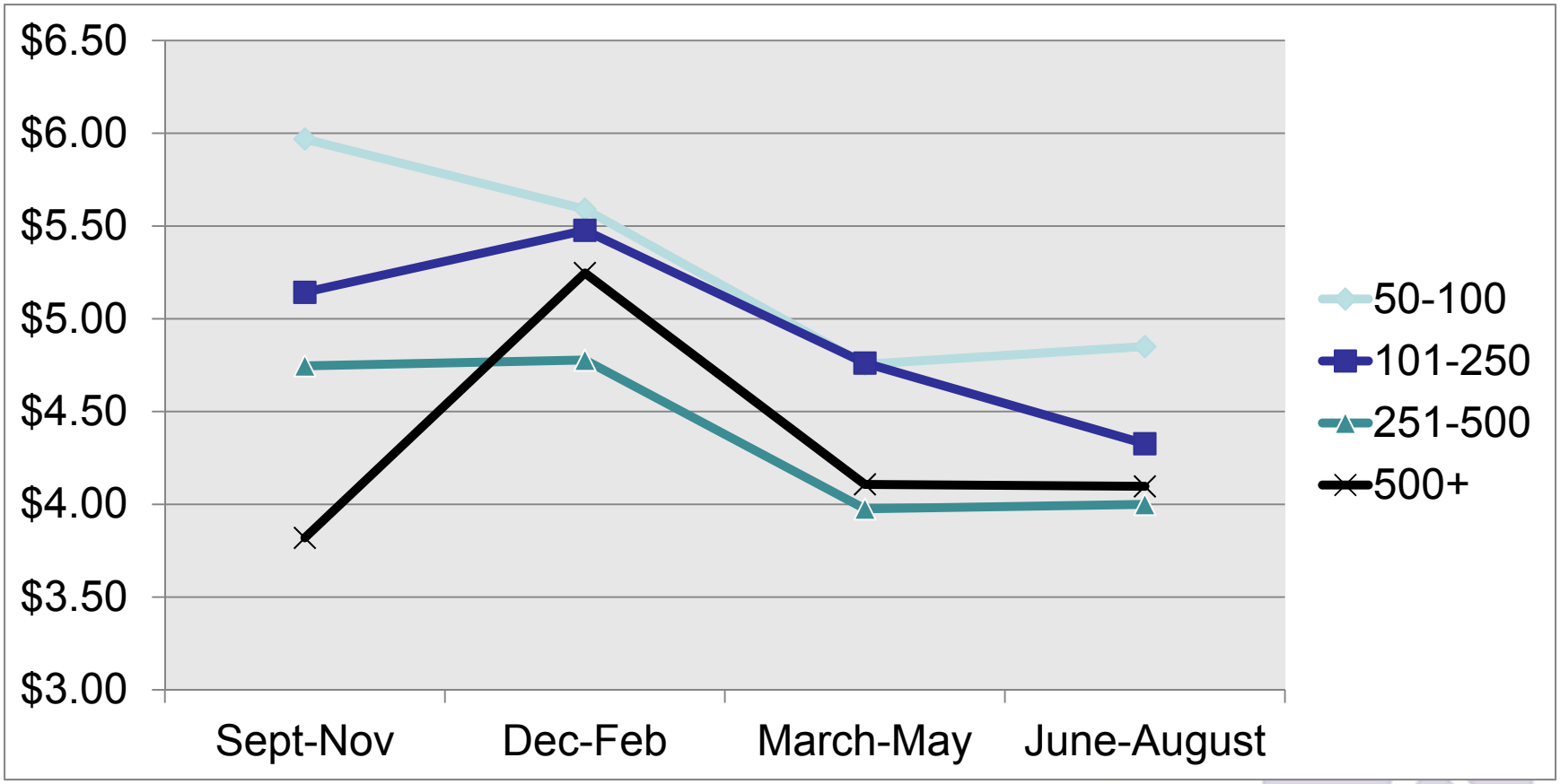
***Inverter warranty**: The solar CREST model has the ability to incorporate two capital expenditures during operations, which could be used to model inverter replacements. In response to recent data and stakeholder feedback, however, this analysis assumes that a 20-year inverter warranty is included in the total installed cost estimate. No additional inverter replacement costs are modeled.*

Mass SREC Database
(Sept 2011-August 2012)

Mass SREC Database - Average Installed Cost by Bin Quarter				
Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	$5.97	$5.59	$4.75	$4.85
101-250	$5.14	$5.48	$4.76	$4.33
251-500	$4.75	$4.78	$3.98	$4.00
500+	$3.82	$5.25	$4.11	$4.10

Mass SREC Database - Average Installed Cost for Target Sizes by Quarter				
Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	$5.05	$4.88	$4.35	$3.84
1000-2500		$5.75	$4.33	$3.98

Mass SREC Database Trend: Average Cost (Sept 2011-August 2012)



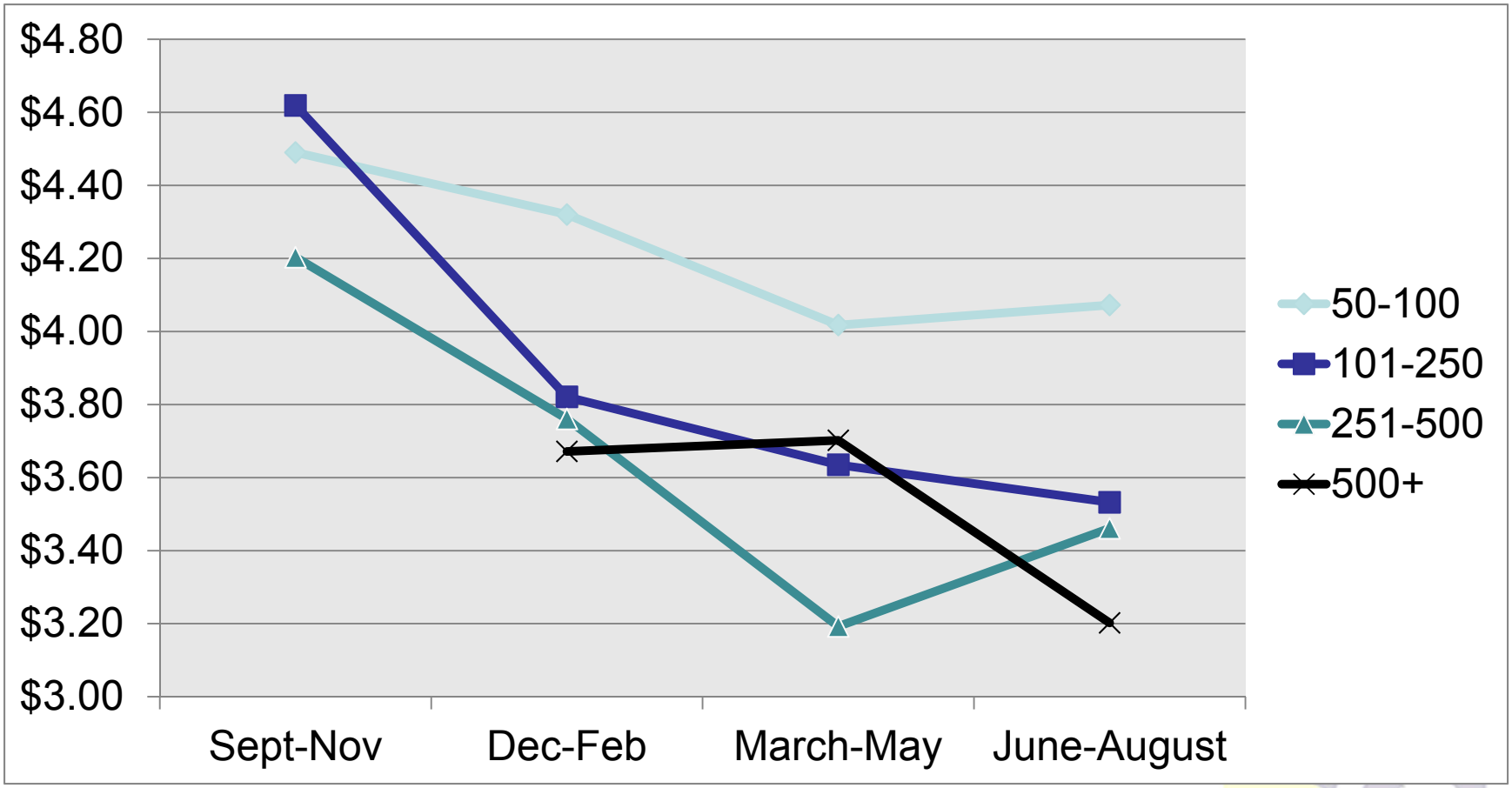
Mass SREC Database: Avg. - 1 Std. Deviation
(Sept 2011 – August 2012)

Mass SREC Database – Avg. Installed Cost minus 1 Std Dev by Qtr.				
Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	$4.49	$4.32	$4.02	$4.07
101-250	$4.62	$3.82	$3.64	$3.53
251-500	$4.20	$3.76	$3.19	$3.46
500+		$3.67	$3.70	$3.20

Mass SREC Database – Avg. Inst. Cost minus 1 Std Dev for Target Sizes by Qtr.				
Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	$4.06	$3.99	$3.79	$2.88*
1000-2500		$4.08	$4.07	$3.13

* StdDev not meaningful due to small sample size.

Mass SREC Database Minus 1 Standard Deviation
(Sept 2011-August 2012)

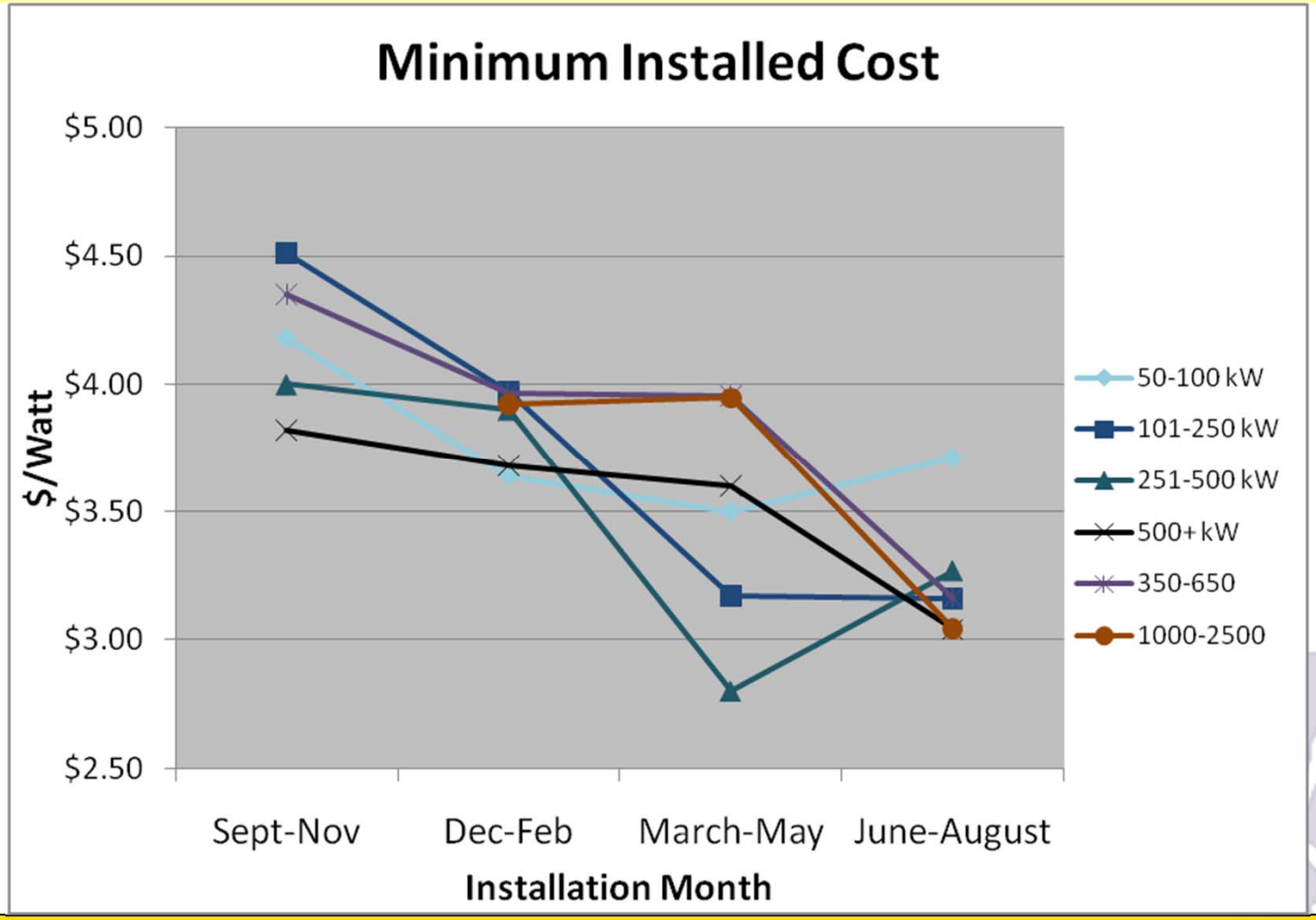


Mass SREC Database: Minimum Installed Cost in Each Bin

Bin	Installation Month (Range)	Min Installed Cost ($/Watt)
50-100	Sept-Nov	$4.18
	Dec-Feb	$3.64
	March-May	$3.50
	June-August	$3.71
101-250	Sept-Nov	$4.51
	Dec-Feb	$3.97
	March-May	$3.17
	June-August	$3.16
251-500	Sept-Nov	$4.00
	Dec-Feb	$3.90
	March-May	$2.80
	June-August	$3.27
500+	Sept-Nov	$3.82
	Dec-Feb	$3.68
	March-May	$3.60
	June-August	$3.04

Target Size	Installation Month (Range)	Min Installed Cost ($/Watt)
350-650	Sept-Nov	$4.35
	Dec-Feb	$3.96
	March-May	$3.95
	June-August	$3.16
1000-2500	Sept-Nov	
	Dec-Feb	$3.92
	March-May	$3.95
	June-August	$3.04

Mass SREC Database: Minimum Installed Cost in Each Bin



NREL National PV Cost Estimates

	Mean Costs	St Dev	Mean – 1 St Dev
<10 kW	$4.78	$0.82	$3.96
10-100	$4.43	$0.54	$3.89
100-1000	$3.67	$0.67	$3.00
1-10MW	$3.38	$0.61	$2.77

Data from: *Distributed Generation Renewable Energy Estimate of Costs*
National Renewable Energy Laboratory, July 2012
http://www.nrel.gov/analysis/pdfs/2012_dg_icoe_data.pdf

Operation & Maintenance (O&M) Cost

Sources

- NREL National PV Cost Estimates

Project Size	Fixed O&M ($/kW-year)	O&M Std Dev
<10 kW	$29	$20
10-100 kW	$26	$19
100-1000 kW	$24	$13
1-10 MW	$22	$10

- MCG experience
- SEA experience
- Stakeholder DR

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (1)

Input category*
Expected Annual Average Net capacity factor, (%) DC **Proposed Input = 14.39%** **2011 Input = 14.39%**
Annual Production Degradation (%) **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $3,100/kW** **2011 Input = $3,900** **+ $70/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $50/kW** **2011 Input = $210/kW**
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22/kW-yr**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (2)

Input category*
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total project costs** **2011 Input = 0.3%**
Project Management, Yr 1 ($/yr) **Proposed Input = $1,400/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $2,500/yr** **2011 Input = $1,500 for 150 kW project**
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Input = yr 1 = *$4,185 (using 90% of $15/1000), basis declines by 10%/yr thereafter to floor of 20% of installed cost*** **2011 Input = $5,250 for 150 kW project, annual adjustment factor = -10.0%**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (3)

Input category*
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. interest rate) of construction financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 yrs; 2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.5%; 2011 Input = 6.5%**
Lender's Fee (% of loan amt) **Proposed Input = same; 2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.40; 2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%; 2011 Input =13%**
Decommissioning Reserve? **Proposed Input = same; 2011 Input = $0 (= salvage value)**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (1)

Input category*
Expected Annual Average Net capacity factor, (%) DC **Proposed Input = 14.39%** **(rationale: 7 of 8 respondents had no comments on what was in 2011)** **2011 Input = 14.39%**
Annual Production Degradation (%) **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $2,750/kW** **2011 Input = $3,900 (excl. Interconnection costs) + $70/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $40/*kW*** **2011 Input = $210/kW**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (2)

Input category*
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22.00/kW**
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total proj. costs** **2011 Input = 0.3%**
Project Management, Yr 1 ($/yr) **Proposed Input = $3,500/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $10,000/yr** **2011 Input = $1,500/yr for 150 kW project**
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Input = yr 1 = *$9,281 (using 90% of $15/1000), basis declines by 10%/yr thereafter to floor of 20% of installed cost*** **2011 Input = $5,250 for 150 kW project, annual adjustment factor = -10.0%**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (3)

Input category*
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. interest rate) of construc. financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 yrs; 2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.5%; 2011 Input = 6.5%**
Lender's Fee (% of loan amt) **Proposed Input = same; 2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.35; 2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 11.5%; 2011 Input =13%**
Decommissioning Reserve? **Proposed Input = same; 2011 Input = $0 (= salvage value)**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (1)

Input category
Expected Annual Avg. Net c.f. (%) **Proposed Input = 14.56%** **(rationale: 7 of 8 respondents had no comments)** **2011 Input = 14.56%**
Annual Production Degradation (%) **Proposed Input = .5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $2,500/kW** **2011 Input = $3,700 (excl. Interconnection costs) +$60/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $300/kW** **2011 Input = $185/kW**

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (2)

Input category
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22/kW**
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total proj. costs** **2011 Input = 0.3%**
Project Management, Yr 1 ($/yr) **Proposed Input = $6,500/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $15,000** **2011 Input = $7,500**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (3)

Input category
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Input = yr 1 = *$15,188 (using 90% of $15/1000), basis declines by 10%/yr thereafter to floor of 20% of installed cost*** **2011 Input = $17,500 annual adjustment factor = -10.0%**
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. int. rate) of constr. financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same** **2011 Input = debt optimized to cash flow**

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (4)

Input category
Debt tenor (years) **Proposed Input = 14 yrs;** **2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.0%** **2011 Input = 6.5%**
Lender's Fee (% of loan amt) **Proposed Input = same;** **2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.35** **2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 11%** **2011 Input = 13%**
Decommissioning Reserve? **Proposed Input = $0 (= salvage value)** **2011 Input = $0 (= salvage value)**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (1)

Input category
Expected Annual Avg. Net capacity factor, (%) **Proposed Input = 14.56%** **2011 Input = 14.65%**
Annual Production Degradation (%) **Proposed Input = .5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input =$2,400** **2011 Input = $3,400 (excl. Interconnection costs) + $50/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $150/kW** **2011 Input = $132/kW**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (2)

Input category
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $15/kW-yr** **2011 Input = $24/kW**
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.25%** **2011 Input = 0.2%**
Project Management, Yr 1 ($/yr) **Proposed Input = $10,000** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $30,000** **2011 Input = $33,000**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (3)

Input category
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 2.5%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Input = yr 1 = *$48,600 (using 90% of $15/1000), basis declines by 10%/yr thereafter to floor of 20% of installed cost*** **2011 Input = $52,500, annual adjustment: -10%**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (4)

Input category
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. interest rate) of construction financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt tenor (years) **Proposed Input = 14 yrs;** **2011 Input = 12 yrs**
Interest rate on debt (%) **Proposed Input = 5.5%** **2011 Input = 6%**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (5)

Input category
Lender's Fee (% of loan amt) **Proposed Input = same;** **2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.35** **2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%** **2011 Input =13%**
Decommissioning Reserve? **Proposed Input = $200,000** **2011 Input = $0 (= salvage value)**

Interconnection

Details, Sources

- National Grid:
  - data from Standard Offer bids, plus
  - random sample of 21 MA & RI projects
- Stakeholder DR

Finance Structure & Costs of Debt and Equity

Details, Sources

- Stakeholder Data Request
- SEA Experience
- Model optimized based on avail cash flows

Incentives

- Federal Investment Tax Credit (ITC) assumed available at time of initial operation (2013/2014)
- Assume Bonus Depreciation no longer available
- Assume full monetization of available tax benefits

- No federal, state, local or other grants assumed

Performance

Details, Sources

- PV Watts assumes no tracking, idealized orientation & tilt
- Stakeholder Data Request
- Inverter conversion factor based on data request and manufacturer input
- MA CEC PTS: actual historic production
- Same adjustments as made in 2011.

Additional Assumptions

- COD achieved in 2013
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio:
  - Min = 1.20X
  - Avg. varies by case
- Interconn. Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Fed. Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- *Assumed NEPOOL Membership costs either covered by NGRID as lead participant, or spread over many installations and therefore negligible*
- Market value of production (assumed revenue) post-contract = 90% of sum of ***solar-weighted*** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	11.95
17	2030	12.18
18	2031	12.42
19	2032	12.66
20	2033	12.91
21	2034	13.16
22	2035	13.41
23	2036	13.67
24	2037	13.94
25	2038	14.21

Benchmarking to CT ZREC Program

October 2012 Results

Large ZREC: 250kW – 1 MW **Medium ZREC**: >100 kW <250 kW **Small ZREC**: ≤ 100 kW ***(All Behind the Meter)***	UI Large ZREC ($/REC)	CL&P Large ZREC ($/REC)	UI Medium ZREC ($/REC)	CL&P Medium ZREC ($/REC)
***Weighted Average* Bid Price of Accepted Bids**	$117.27	$101.36	$135.36	$149.29
	6 accepted bids: All but 1 winner <500 kW	Winners span whole size range.	Winners range from 132 – 250 kW	Winners range from 101 – 250 kW
Approx. Value of Retail Electricity Purchases Avoided	$133-153		$133-153	
Est. Value Under 3rd-Party Net Metering (Assumed 10-15% discount, common in MA)	$113-138		$113-138	
Est. Equivalent to Calculated LCOE	$230-255		$248-273	

Est. of 15-year levelized contract: Solar

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	**Estimated Contract Price (¢/kWh)**			
	50-100 kW	101-250 kW	251-499 kW	500 kW and above
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	27.55	26.35	25.65	21.35
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	28.25	26.85	26.15	21.75
Average = Proposed Ceiling Price	**27.90**	**26.60**	**25.90**	**21.55**
2011 Ceiling Prices	***33.35 (150 kW)***	***33.35 (150 kW)***	***31.60***	***28.95***

WIND

Researched cost, O&M and financing inputs: Wind 1,500 kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 27.5% *(to account for new turbine optimization to low wind regimes)*** **2011 Input = 25%**
Annual Production Degradation **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost **Proposed Input = $3,200/kW** **2011 Input = $2,750/kW** **(excl. interconnection costs)**
Typical Interconnection cost ($/kW) **Proposed Input = $100/kW** **2011 Input = $117/kW**
O&M expenses in Year 1 of operations **Proposed Input = $30/kW-yr** **2011 Input = $55/kW-year**
Insurance Expense (as % of total proj. cost, or in $/yr) **Proposed Input = 0.3% of total project cost** **2011 Input = included in O&M**

Researched cost, O&M and financing inputs: Wind 1,500 kW (2)

Input category
Project Management **Proposed Input = $15,000/yr** **2011 Input = included in O&M**
Land Lease, Year 1 ($/year) **Proposed Input = $20,000/yr** **2011 Input = included in O&M**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%** **2011 Input = 2%**
Royalties **Proposed Input = included in lease exp.** **2011 Input = included in O&M**
Property Taxes **Proposed Input, yr 1 = *$64,800 (using 90% of $15/$1000), basis declines 10%/yr thereafter to floor of 20% of inst. cost*** **2011 Input = included in O&M**
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**

Researched cost, O&M and financing inputs: Wind 1,500 kW (3)

Input category
Source and Cost of Construction Financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 15 yrs** **2011 Input = 12 Yrs.**
Interest rate on debt (%) **Proposed Input = 5.5%** **2011 Input = 6.5%**
Lender's Fee **Proposed Input = same;** **2011 Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 11% with PTC; 10% w/o PTC** **2011 Input = 13%**
Decommissioning Reserve **Proposed Input = $0 (= salvage value)** **2011 Input = $0 (= salvage value)**

Researched cost, O&M and financing inputs: Wind 750 kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 24%**
Annual Production Degradation **Proposed Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost **Proposed Input = $2,800**
Typical Interconnection cost ($/kW) **Proposed Input = $137/kW**
O&M expenses (in ¢/kWh) in Year 1 of operations **Proposed Input = $30/kW-yr**
Insurance Expense (as % of total project cost, or in $/yr) **Proposed Input = 0.3% of total proj. costs**
Project Management **Proposed Input = $15,000**
Land Lease, Year 1 ($/year) **Proposed Input = $10,000**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%**

Researched cost, O&M and financing inputs: Wind 750 kW (2)

Input category
Royalties **Proposed Input = included in lease exp.**
Property Taxes **Proposed Input, yr 1 = *$28,350 (using 90% of $15/$1000), basis declines 10%/yr thereafter to floor of 20% of inst. cost***
Length of construction period (months) **Proposed Input = included in installed costs;**
Source and Cost of Construction Financing **Proposed Input = included in installed costs;**
Debt-to-equity ratio **Proposed Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 15 yrs**
Interest rate on debt (%) **Proposed Input = 6%**
Lender's Fee **Proposed Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%**
Decommissioning Reserve **Proposed Input = $0 (salvage value)**

Researched cost, O&M and financing inputs: Wind 100kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 23%**
Annual Production Degradation **Proposed Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost ***Proposed Input = $5,600/kW***
Typical Interconnection cost ($/kW) **Proposed Input = $200/kW**
O&M expenses (in $/kW-year) in Year 1 of operations **Proposed Input = $20/kW-yr**
Insurance Expense (as % of total project cost, or in $/yr) **Proposed Input = 0.3% of total proj. costs**

Researched cost, O&M and financing inputs: Wind 100kW (2)

Input category
Project Management **Proposed Input = $2,000**
Land Lease, Year 1 ($/year) **Proposed Input = $2000/year**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%**
Royalties **Proposed Input = included in lease exp.**
Property Taxes **Proposed Input = assumed exempt**
Length of construction period (months) **Proposed Input = included in installed costs;**

Researched cost, O&M and financing inputs: Wind 100kW (3)

Input category
Source and Cost of Construction Financing **Proposed Input = included in installed costs;**
Debt-to-equity ratio **Proposed Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 15 yrs**
Interest rate on debt (%) **Proposed Input = 6%**
Lender's Fee **Proposed Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%**
Decommissioning Reserve **Proposed Input = $0 (salvage value)**

Capital Cost, Installed

(Includes soft costs & construction financing; excludes Interconnection)

Details, Sources

- Stakeholder DR
- SEA Experience
- Interviews

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

O&M Cost

Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience

Interconnection

Details, Sources

- Stakeholder DR
- National Grid: random sample of projects in RI & MA

Finance Structure & Costs of Debt and Equity

Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience
- Model optimized based on available cash flows

Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without PTC extension.
  - For 100 kW wind, assume ITC available through 2016.
- Assume Bonus Depreciation no longer available
- Assume full monetization of available tax benefits

- No federal, state, local or other grants assumed

Performance

Details, Sources

- Stakeholder DR
- SEA Experience
- MA CEC PTS
- Adjustment made for recent improvements in low wind-speed turbine performance, per SEA analysis.

Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.35X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90% of sum of ***wind-weighted*** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (see next slide)

Additional Assumptions:

Forecast of Market Value of Production

Project Year	Calendar Year	Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	11.46
17	2030	11.68
18	2031	11.91
19	2032	12.13
20	2033	12.37

Est. of 15-year levelized contract: Wind

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	**Estimated Contract Price (cents/kWh)**				
	1.5 MW		750 kW		100 kW
	w/PTC	w/o PTC	w/PTC	w/o PTC	
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	15.55	17.65	17.45	19.25	24.25
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	15.95	17.95	17.75	19.55	24.85
Average = Proposed Ceiling Price	**15.75**	17.80	**17.60**	**19.40**	**24.55**
2011 Ceiling Price	***13.35***	***N/A***	***N/A***	***N/A***	***N/A***

ANAEROBIC DIGESTION

Anaerobic Digestion - Overview

- The most common opportunity for AD in RI is *assumed* to be for food waste digesters. Sludge or manure-based applications are also possible.

- Feed stocks are expected to be derived from food manufacturing, restaurant and grocery waste. *No manure or WWTP sludge are assumed – although such projects may be possible in RI. Economics will vary; VT Standard Offer established farm digester price esc. from 13.6 to 15.0 cents/kWh over 20 years.*

- This approach means that there are *no fuel costs*. Fuel deliveries will generate a *tipping fee*, and are assumed to arrive clean, with no cost to dispose of packaging.

- Further, it is assumed that digestate will be sold, generating additional revenue for the facility.

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (1)

Input category
Biogas consumption/day (ft^3/day) **Proposed Input** = **175,000**
Energy content/cubic foot (BTU/cubic ft) **Proposed Input** = **650** BTU/cubic ft
Heat Rate (BTU/kWh) **Proposed Input** = **9,000** BTU/kWh
Availability Factor **Proposed Input** = **92**%
Station Service/Parasitic Load **Proposed Input** = **10**%
Annual Production Degradation (%) **Proposed Input** = **0**%
Total installed cost ($/kW), excl. Interconnection Cost **Proposed Input** = $**9,500**/kW

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (2)

Input category
Typical Interconnection cost ($) **Proposed Input** = $**150,000**
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below) **Proposed Input** = $**300**/kW-yr
Variable O&M (¢/kWh), Yr 1 (excluding those listed below) **Proposed Input** = **2**¢/kWh
Insurance, Yr 1, (provide as % of total project cost, or in $/yr) **Proposed Input** = **0.4%**
Project Management, Yr 1 ($/yr) **Proposed Input** = $**30,000**/yr

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (3)

Input category
Land Lease, Yr 1 ($/yr) **Proposed Input** = $**5,000**/yr
Annual average escalation rate for O&M expenses (%) **Proposed Input** = **2** %
Royalties (% of revenue, or $/yr) **Proposed Input** = **0%**
Property Taxes ($ in Yr 1 and annual adjustment factor, or as annual estimates with methodology clearly described) **Proposed Input, yr 1 = $64,125** ***(using 90% of $15/$1000), basis declines 10%/yr thereafter to floor of 20% of inst. cost***
Length of construction period (months) **Proposed Input** = **included in installed costs;**
Source and Cost of Construction Financing **Proposed Input** = **included in installed costs;**
Debt-to-equity ratio **Proposed Input** = **debt optimized to cash flow**

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (4)

Input category
Debt tenor (years) **Proposed Input** = **13** years
Interest rate on debt (%) **Proposed Input** = **7** %
Lender's Fee **Proposed Input** = **included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input** = **1.5**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input** = **12** %
Decommissioning Reserve **Proposed Input** = **$0**
Tipping Fees/Digestate Revenue, If Applicable: $/ton, and tons per year **Proposed Input** = **Tipping Fee: $10/ton; 10,000 tons per year** **Digestate: 7 cents/gal.; 4M gal/yr**

Details, Sources

Capital Cost, Installed (Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder DR
- Interviews

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

O&M

- Stakeholder DR

Interconnection

- Stakeholder DR

Finance Structure and Cost of Debt & Equity

- Stakeholder DR
- Model optimized based on available cash flows

Performance

- Stakeholder DR

Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - Anaerobic digesters eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
- Assume Bonus Depreciation no longer available
- Assume full monetization of available tax benefits

- No federal, state, local or other grants assumed

Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.50X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (see next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	11.54
17	2030	11.76
18	2031	11.99
19	2032	12.22
20	2033	12.46

Est. of 15-year levelized contract: Anaerobic Digestion

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)	
	500 kW	
	w/PTC	w/o PTC
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	13.65	14.75
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	13.95	15.15
Average = Proposed Ceiling Price	**13.80**	**14.95**

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Rhode Island Distributed Generation Standard Offer:

Preliminary Input Assumptions & Modeling Results for 2013 Ceiling Price Review

November 7, 2012

Sustainable Energy Advantage, LLC
(with support from Meister Consultants Group)

2013 Ceiling Prices to be established for 9 Classes…

- 4 Solar
- 3 Wind
- 1 Anaerobic Digestion
- 1 Hydro benchmark (*not official CP for 2013*)
- 'standard' installations will be modeled to inform setting of ceiling rates for each class

Technology, sub class	Eligible Size Range	Standard Size for Modeling Ceiling Price
Solar, Large	500 kW and above	1.5 MW
Solar, Medium 2	251 – 499 kW	500 kW
Solar, Medium 1	101 – 250 kW	250 kW
Solar, Small	50 – 100 kW	100 kW
Wind, Large	1.0 MW – 1.5 MW	1.5 MW
Wind, Medium	200 kW – 999 kW	750 kW
Wind, Small	90 – 100 kW	100 kW
Anaerobic Digestion	400 – 500 kW	500 kW
Hydroelectric	500 kW – 1.0 MW	1.0 MW

Summary Comparison of 2011/2012 to Proposed 2013 Ceiling Prices

Technology, sub-class	2011/2012 Ceiling Price (¢/kWh)	2013 Proposed Ceiling Price (¢/kWh) w/PTC	Net Change* btw previous and proposed Ceiling Prices	2013 Proposed Ceiling Price (¢/kWh) w/o PTC
Solar, 500 kW+	28.95	24.95	-14%	N/A
Solar, 251 – 499 kW	31.60	28.40	-10%	N/A
Solar, 101 – 250 kW	33.35 (for 150 kW)	28.80	-14%	N/A
Solar, 50 – 100 kW	33.35 (for 150 kW)	29.95	-10%	N/A
Wind, 1 – 1.5 MW	13.35	16.80	+26%	18.60
Wind, 400 – 999 kW	N/A	18.15	N/A	19.95
Wind, 90 – 100 kW	N/A	24.65	N/A	N/A
AD, 400 – 500 kW	N/A	18.55	N/A	19.55
Hydro, 500 kW – 1 MW	N/A	17.90	N/A	18.85

** See next slide*

Comparison of 2011/2012 to Proposed 2013 Ceiling Prices, Cont.

- A reduction in the market-based total installed cost of solar PV was the principle driver of the proposed reduction in Standard Offer prices for solar.
- The availability of actual cost data for 1.5 MW wind turbine generators installed in southeastern MA was the principle driver of the proposed increase in the Standard Offer price for 1.5 MW Wind.
- 2 additional factors played an important role in the analytical review of proposed 2013 CPs:
  1. The availability of **bonus depreciation** (100% in 2011, and 50% in 2012) is **scheduled to cease** for projects coming on-line beginning 1/1/2013. All else equal, the removal of 50% bonus depreciation would cause an increase in the cost of energy – estimated at 7% for 1.5 MW solar and 8% for 1.5 MW wind.
  2. The **expiration of the 1603 cash payment** in lieu of the ITC significantly reduces most investors' ability to fully monetize the Investment Tax Credit. This analysis estimates 90% ITC monetization. All else equal, reducing the ITC benefit by 10% would cause an increase in the cost of energy – estimated at 4% for 1.5 MW solar. For wind, reduced monetization plus the expiration of the ability to use the ITC (or 1603 payment) in lieu of the PTC could cause an increase in the cost of energy of up to 25%.

As a result, proposed CPs demonstrate a *net* reduction ranging between 10% and 14% for solar, and a *net* increase for wind of approximately 26%.

Est. Impact of Changes in Federal Incentives on LCOE

	Solar, 1.5 MW		Wind, 1.5 MW	
	Impact of Fed. Inc.	Net Change	Impact of Fed. Inc.	Net Change
Sunset of (50%) Bonus Depreciation	+ 7%	- 14%	+8%	+ 26%
90% monetization; + Switch from ITC to PTC for Wind	+ 4%		+ 2% + 14%	

SOLAR

Est. of 15-year levelized contract: Solar

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	**Estimated Contract Price (cents/kWh)**			
	50-100 kW	101-250 kW	251-499 kW	500 kW and above
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	29.65	28.55	28.15	24.75
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	30.25	29.05	28.65	25.15
Average = Proposed Ceiling Price	**29.95**	**28.80**	**28.40**	**24.95**
2011 Ceiling Prices	***33.35 (150 kW)***	***33.35 (150 kW)***	***31.60***	***28.95***

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (1)

Input category*
Expected Annual Average Net capacity factor, (%) DC **Proposed Input = 14.39%** **(rationale: 7 of 8 respondents had no comments on what was in 2011)** **2011 Input = 14.39%**
Annual Production Degradation (%) **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $3,100 -> $3,150/kW** **2011 Input = $3,900** **+ $70/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $50/kW** **2011 Input = $210/kW**
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22/kW-yr**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (2)

Input category*
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total proj. costs** **2011 Input = 0.3%**
Project Management, Yr 1 ($/yr) **Proposed Input = $1,400/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $2,500/yr** **2011 Input = $1,500 for 150 kW project**
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%** **2011 Input = $5,250 for 150 kW project,** **annual adjustment factor = -10.0%**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 100 kW dc (3)

Input category*
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. interest rate) of construction financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same (result = 48%)** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.5%; 2011 Input = 6.5%**
Lender's Fee (% of loan amt) **Proposed Input = same; 2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.40; 2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%; 2011 Input =13%**
Decommissioning Reserve? **Proposed Input = same; 2011 Input = $0 (= salvage value)**

*There was no 100kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (1)

Input category*
Expected Annual Average Net capacity factor, (%) DC **Proposed Input = 14.39%** **(rationale: 7 of 8 respondents had no comments on what was in 2011)** **2011 Input = 14.39%**
Annual Production Degradation (%) **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $2,750 -> $2650/kW** **2011 Input = $3,900** **(excl. Interconnection costs)** **+ $70/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $40/*kW*** **2011 Input = $210/kW**
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22.00/kW**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (2)

Input category*
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total proj. costs** **2011 Input = 0.3%**
Project Management, Yr 1 ($/yr) **Proposed Input = $3,500/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $10,000/yr** **2011 Input = $1,500/yr for 150 kW project**
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%** **2011 Input = $5,250 for 150 kW project, annual adjustment factor = -10.0%**
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 250 kW dc (3)

Input category*
Source (D/E) and Cost (e.g. interest rate) of construc. financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same (result = 48.75%)** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 -> 13 yrs; 2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.5%; 2011 Input = 6.5%**
Lender's Fee (% of loan amt) **Proposed Input = same; 2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.35; 2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 11.5%; 2011 Input =13%**
Decommissioning Reserve? **Proposed Input = same; 2011 Input = $0 (= salvage value)**

*There was no 250kW CP in 2011. The 2011 150 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (1)

Input category
Expected Annual Avg. Net c.f. (%) **Proposed Input = 14.56%** **(rationale: 7 of 8 respondents had no comments)** **2011 Input = 14.56%**
Annual Production Degradation (%) **Proposed Input = .5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input = $2,500 -> $2,650/kW** **2011 Input = $3,700** **(excl. Interconnection costs)** **+$60/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $300/kW** **2011 Input = $185/kW**
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $20/kW-yr** **2011 Input = $22/kW**
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.3% of total proj. costs** **2011 Input = 0.3%**

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (2)

Input category
Project Management, Yr 1 ($/yr) **Proposed Input = $6,500/yr** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $15,000** **2011 Input = $7,500**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 3%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%** **2011 Input = $17,500 annual adjustment factor = -10.0%**

Researched cost, O&M and financing inputs: Solar ≈ 450 kW dc (3)

Input category
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. int. rate) of constr. financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same (result = 51.5%)** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 -> 13 yrs** **2011 Input = 12 years**
Interest rate on debt (%) **Proposed Input = 6.0%** **2011 Input = 6.5%**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (1)

Input category
Expected Annual Avg. Net capacity factor, (%) **Proposed Input = 14.65%** **(rationale: 7 of 8 respondents had no comments** **2011 Input = 14.65%**
Annual Production Degradation (%) **Proposed Input = .5%** **2011 Input = 0.5%**
Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost **Proposed Input =$2,400 -> $2,550/kW** **2011 Input = $3,400 (excl. Interconnection costs) + $50/kW 20-yr inverter warranty**
Interconnection cost ($) **Proposed Input = $150/kW** **2011 Input = $132/kW**
O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations **Proposed Input = $15/kW-yr** **2011 Input = $24/kW**
Insurance, Yr 1, (% of total project costs or $/yr) **Proposed Input = 0.25%** **2011 Input = 0.2%**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (2)

Input category
Project Management, Yr 1 ($/yr) **Proposed Input = $10,000** **2011 Input= included in overall O&M**
Land Lease, Yr 1 ($/yr) **Proposed Input = $30,000 -> $34,500 to reflect tax on underlying land** **2011 Input = $33,000**
Annual average escalation rate for O&M expenses (%) **Proposed Input = 3%** **2011 Input = 2.5%**
Royalties (% of Revenue, or $/yr) **Proposed Input = 0.0% (covered in lease)** **2011 Input = 0.0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%** **2011 Input = $52,500, annual adjustment: -10%**
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Source (D/E) and Cost (e.g. interest rate) of construction financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**

Researched cost, O&M and financing inputs: Solar ≈ 1,500 kW dc (3)

Input category
Debt-to-equity ratio **Proposed Input = same (result = 51.25%)** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 14 -> 13 yrs** **2011 Input = 12 yrs**
Interest rate on debt (%) **Proposed Input = 5.5%** **2011 Input = 6%**
Lender's Fee (% of loan amt) **Proposed Input = same;** **2011 Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.35** **2011 Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%** **2011 Input =13%**
Decommissioning Reserve? **Proposed Input = $200,000** **2011 Input = $0 (= salvage value)**

Incentives

- Federal Investment Tax Credit (ITC) assumed available at time of initial operation (2013/2014)
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed

Additional Assumptions

- COD achieved in 2013
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio:
  - Min = 1.20X
  - Avg. varies by case
- Interconn. Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Fed. Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- *Assumed NEPOOL Membership costs either covered by NGRID as lead participant, or spread over many installations and therefore negligible*
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of ***solar-weighted*** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	10.04
17	2030	10.24
18	2031	10.43
19	2032	10.63
20	2033	10.84
21	2034	11.05
22	2035	11.26
23	2036	11.47
24	2037	11.70
25	2038	11.92

Benchmarking to CT ZREC Program

October 2012 Results

Large ZREC: 250kW – 1 MW **Medium ZREC**: >100 kW <250 kW **Small ZREC**: ≤ 100 kW ***(All Behind the Meter)***	UI Large ZREC ($/REC)	CL&P Large ZREC ($/REC)	UI Medium ZREC ($/REC)	CL&P Medium ZREC ($/REC)
***Weighted Average* Bid Price of Accepted Bids**	$117.27	$101.36	$135.36	$149.29
	6 accepted bids: All but 1 winner <500 kW	Winners span whole size range.	Winners range from 132 – 250 kW	Winners range from 101 – 250 kW
Approx. Value of Retail Electricity Purchases Avoided, Levelized*	$166-191		$166-191	
Est. Value Under 3rd-Party Net Metering (Assumed 10-15% discount, common in MA)	$113-138		$113-138	
Est. Equivalent to Calculated LCOE	$258-289		$276-307	

** Levelization assumes 4% annual rate escalation and 10% discount rate.*

WIND

Est. of 15-year levelized contract: Wind

In 2011, LCOE modeling was performed under two scenarios, and the ceiling price was established as the arithmetic average of the 2 cases. For 2013, we propose to use the same approach.

Scenario (Modeling Assumptions)	**Estimated Contract Price (cents/kWh)**				
	1.5 MW		750 kW		100 kW
	w/PTC	w/o PTC	w/PTC	w/o PTC	
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	16.65	18.45	17.95	19.85	24.35
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	16.95	18.75	18.35	20.05	24.95
Average = Proposed Ceiling Price	**16.80**	**18.60**	**18.15**	**19.95**	**24.65**
2011 Ceiling Price	***13.35***	***N/A***	***N/A***	***N/A***	***N/A***

Researched cost, O&M and financing inputs: Wind 1,500 kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 27.5% *(to account for new turbine optimization to low wind regimes)*** **2011 Input = 25%**
Annual Production Degradation **Proposed Input = 0.5%** **2011 Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost **Proposed Input = $3,200/kW** **2011 Input = $2,750/kW (excl. interconnection costs)**
Typical Interconnection cost ($/kW) **Proposed Input = $100/kW** **2011 Input = $117/kW**
O&M expenses in Year 1 of operations **Proposed Input = $30/kW-yr** **2011 Input = $55/kW-year**

Researched cost, O&M and financing inputs: Wind 1,500 kW (2)

Input category
Insurance Expense (as % of total proj. cost, or in $/yr) **Proposed Input = 0.3% of total project cost** **2011 Input = included in O&M**
Project Management **Proposed Input = $15,000/yr** **2011 Input = included in O&M**
Land Lease, Year 1 ($/year) **Proposed Input = $20,000/yr** **2011 Input = included in O&M**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%** **2011 Input = 2%**
Royalties **Proposed Input = included in lease exp.** **2011 Input = included in O&M**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%**
Length of construction period (months) **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**

Researched cost, O&M and financing inputs: Wind 1,500 kW (3)

Input category
Source and Cost of Construction Financing **Proposed Input = included in installed costs;** **2011 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = same (56.25%)** **2011 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 15 yrs** **2011 Input = 12 Yrs.**
Interest rate on debt (%) **Proposed Input = 5.5%** **2011 Input = 6.5%**
Lender's Fee **Proposed Input = same;** **2011 Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 11% -> 12%** **2011 Input = 13%**
Decommissioning Reserve **Proposed Input = $0 (= salvage value)** **2011 Input = $0 (= salvage value)**

Researched cost, O&M and financing inputs: Wind 750 kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 24%**
Annual Production Degradation **Proposed Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost **Proposed Input = $2,800**
Typical Interconnection cost ($/kW) **Proposed Input = $137/kW**
O&M expenses (in ¢/kWh) in Year 1 of operations **Proposed Input = $30/kW-yr**
Insurance Expense (as % of total project cost, or in $/yr) **Proposed Input = 0.3% of total proj. costs**
Project Management **Proposed Input = $15,000**
Land Lease, Year 1 ($/year) **Proposed Input = $10,000**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%**

Researched cost, O&M and financing inputs: Wind 750 kW (2)

Input category
Royalties **Proposed Input = included in lease exp.**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%**
Length of construction period (months) **Proposed Input = included in installed costs;**
Source and Cost of Construction Financing **Proposed Input = included in installed costs;**
Debt-to-equity ratio **Proposed Input = debt optimized to cash flow (result = 66%)**
Debt tenor (years) **Proposed Input = 15 yrs**
Interest rate on debt (%) **Proposed Input = 6%**
Lender's Fee **Proposed Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%**
Decommissioning Reserve **Proposed Input = $0 (salvage value)**

Researched cost, O&M and financing inputs: Wind 100kW (1)

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 23%**
Annual Production Degradation **Proposed Input = 0.5%**
Total installed cost ($/kW), **excluding** Interconnection Cost ***Proposed Input = $5,600/kW***
Typical Interconnection cost ($/kW) **Proposed Input = $200/kW**
O&M expenses (in $/kW-year) in Year 1 of operations **Proposed Input = $20/kW-yr**
Insurance Expense (as % of total project cost, or in $/yr) **Proposed Input = 0.3% of total proj. costs**
Project Management **Proposed Input = $2,000**
Land Lease, Year 1 ($/year) **Proposed Input = $2000/year**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%**
Royalties **Proposed Input = included in lease exp.**

Researched cost, O&M and financing inputs: Wind 100kW (2)

Input category
Property Taxes **Proposed Input = assumed exempt**
Length of construction period (months) **Proposed Input = included in installed costs;**
Source and Cost of Construction Financing **Proposed Input = included in installed costs;**
Debt-to-equity ratio **Proposed Input = debt optimized to cash flow (result = 50.25%)**
Debt tenor (years) **Proposed Input = 15 yrs**
Interest rate on debt (%) **Proposed Input = 6%**
Lender's Fee **Proposed Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%**
Decommissioning Reserve **Proposed Input = $0 (salvage value)**

Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without PTC extension.
    - For these categories, monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
  - For 100 kW wind, assume ITC available and fully monetized through 2016.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed

Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.35X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of ***wind-weighted*** energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (see next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Time-of-Production Weighted Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.63
17	2030	9.82
18	2031	10.01
19	2032	10.20
20	2033	10.39

ANAEROBIC DIGESTION

Est. of 15-year levelized contract: Anaerobic Digestion

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)	
	500 kW	
	w/PTC	w/o PTC
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	18.35	19.35
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	18.75	19.75
Average = Proposed Ceiling Price	**18.55**	**19.55**

Anaerobic Digestion - Overview

- The most common opportunity for AD in RI is *assumed* to be for food waste digesters. Sludge or manure-based applications are also possible.

- Feed stocks are expected to be derived from food manufacturing, restaurant and grocery waste. *No manure or WWTP sludge are assumed – although such projects may be possible in RI.*
- *The VT Standard Offer program established a farm digester price which esc. from 13.6 to 15.0 cents/kWh over a 20 year contract. The VT Standard Offer contract allows the generator to keep and sell all RECs – and retain associated revenue.*

- This approach means that there are *no fuel costs*. Fuel deliveries will generate a *tipping fee*, and are assumed to arrive clean, with no cost to dispose of packaging.

- ~~Further, it is assumed that digestate will be sold, generating additional revenue for the facility.~~

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (1)

Input category
Biogas consumption/day (ft^3/day) **Proposed Input** = **150,000**
Energy content/cubic foot (BTU/cubic ft) **Proposed Input** = **650** BTU/cubic ft
Heat Rate (BTU/kWh) **Proposed Input** = **9,000** BTU/kWh
Availability Factor **Proposed Input** = **92**%
Station Service/Parasitic Load **Proposed Input** = **10**%
Annual Production Degradation (%) **Proposed Input** = **0**%
Total installed cost ($/kW), excl. Interconnection Cost **Proposed Input** = $**9,500 -> $10,000/kW -- additional $500/kW takes into account ownership of land**
Typical Interconnection cost ($) **Proposed Input** = $**150,000**

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (2)

Input category
O&M expenses ($/kW-yr), Yr 1 (excluding those listed below) **Proposed Input** = $**300**/kW-yr
Variable O&M (¢/kWh), Yr 1 (excluding those listed below) **Proposed Input** = **2**¢/kWh
Insurance, Yr 1, (provide as % of total project cost, or in $/yr) **Proposed Input** = **0.4%**
Project Management, Yr 1 ($/yr) **Proposed Input** = $**30,000**/yr
Land Lease, Yr 1 ($/yr) **Proposed Input** = **$5,000 -> $0/yr (land assumed purchased by the project @ equivalent of $500/kW)**
Annual average escalation rate for O&M expenses (%) **Proposed Input** = **2** %
Royalties (% of revenue, or $/yr) **Proposed Input** = **0%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%**

Researched cost, O&M and financing inputs: Anaerobic Digestion, ~500 kW (3)

Input category
Length of construction period (months) **Proposed Input** = **included in installed costs;**
Source and Cost of Construction Financing **Proposed Input** = **included in installed costs;**
Debt-to-equity ratio **Proposed Input** = **debt optimized to cash flow**
Debt tenor (years) **Proposed Input** = **13** years
Interest rate on debt (%) **Proposed Input** = **7** %
Lender's Fee **Proposed Input** = **included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input** = **1.5**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input** = **12** %
Decommissioning Reserve **Proposed Input** = **$0**
Tipping Fees/Digestate Revenue, If Applicable: $/ton, and tons per year **Proposed Input** = **Tipping Fee: $10 -> $30/ton ; Digestate: 7¢ -> 0¢/gal.**

Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - Anaerobic digesters eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed

Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 20 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.50X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 90 -> 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (see next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.70
17	2030	9.89
18	2031	10.08
19	2032	10.27
20	2033	10.46

HYDRO

Est. of 15-year levelized contract: Hydro

Scenario (Modeling Assumptions)	Estimated Contract Price (cents/kWh)	
	1,000 kW	
	w/PTC	w/o PTC
Debt optimized to meet both min + average DSCR; Tax Benefits utilized as generated	17.75	18.75
Debt optimized to meet both min + average DSCR; NOL carried forward and used only by project	18.05	18.95
Average = Proposed Ceiling Price	**17.90**	**18.85**

Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category
Expected Annual Average Net capacity factor, (%) **Proposed Input = 40%**
Total installed cost ($/kW), **excluding** Interconnection Cost **Proposed Input = $4,000/kW (excl. interconnection costs)**
Typical Interconnection cost ($/kW) **Proposed Input = $100/kW**
O&M expenses (in $/kW-year) in Year 1 of operations **Proposed Input = $13/kW-year**
Variable O&M (¢/kWh), Yr 1 (excluding those listed below) **Proposed Input = 2.00 ¢/kWh**
Insurance Expense (as % of total project cost, or in $/yr) **Proposed Input = 0.5%**
Project Management **Proposed Input = $30,000/year**

Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category
Land Lease, Year 1 ($/year) **Proposed Input = (see royalties)**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%**
Royalties **Proposed Input = 3.5%**
Property Taxes ($ in Yr 1 and annual adjustment factor) **Proposed Inputs: Cost basis = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%**
Length of construction period (months) **Proposed Input = included in installed costs**
Source and Cost of Construction Financing **Proposed Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = debt optimized to cash flow**

Researched cost, O&M and financing inputs: Hydro 500-1000kW

Input category
Debt tenor (years) **Proposed Input = 14 Yrs.**
Interest rate on debt (%) **Proposed Input = 6.75%**
Lender's Fee **Proposed Input = included in cap. cost**
Avg. Debt Service Coverage Ratio **Proposed Input = 1.45**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%**
Decommissioning Reserve **Proposed Input = $0**

Incentives

- Current Production Tax Credit (PTC) expires as of 12/31/2012.
  - Hydro is eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
  - Monetization assumption reduced to 90% to reflect the difficulty and cost of securing tax equity as well as the associated transaction costs.
- Assume Bonus Depreciation no longer available
- Proposed CPs are an average of two modeling runs – one which assumes state tax benefits are used as generated, and a second which assumes the Net Operating Loss is carried forward until it can be used by the project.
- No federal, state, local or other grants assumed

Additional Assumptions

- Commercial operation achieved in 2013
- Project Useful Life: 30 years
- Minimum Debt Service Coverage Ratio: 1.20X
- Average Debt Service Coverage Ratio: 1.45X
- Interconnection Costs depreciated on 15-year MACRS schedule
- All other project costs:
  - 96% depreciated on 5-year MACRS
  - 2% depreciated on 15-year MACRS
  - 2% not depreciable
- Federal Income Tax rate 35%; State rate 9%
- All tax benefit utilized in period generated, unless otherwise noted
- Market value of production (assumed revenue) post-contract = 75% of sum of energy and capacity price forecasts from 2011 Avoided Energy Supply Cost Study and $5/REC (see next slide)

Additional Assumptions:
Forecast of Market Value of Production

Project Year	Calendar Year	Market Value of Production (incl. energy, capacity & RECs) (cents/kWh)
16	2029	9.70
17	2030	9.89
18	2031	10.08
19	2032	10.27
20	2033	10.46
21	2034	10.66
22	2035	10.87
23	2036	11.08
24	2037	11.29
25	2038	11.51
26	2039	11.73
27	2040	11.95
28	2041	12.18
29	2042	12.37
30	2043	12.56

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APPENDIX A - SOLAR

Capital Cost, Installed: Details, Sources

(Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder Data Request
  - Responses received from stakeholders: solar (12), wind (9), anaerobic digestion (5) and hydro (5)
- Follow up Interviews; Data available to SEA through other recent engagements
- Industry Databases Polled

Usable data extracted from:

- MA SREC Database [installed cost data analyzed from projects installed within the last 3, 6, and 9 months]
- NREL July 2012 distributed generation cost estimates

Database reviewed; data of limited direct usefulness, from:

- NYSERDA PowerClerks Database (Only systems <100 kW; access to raw data not available)
- California Solar Initiative Database (Data concerns, inconsistency with more relevant databases)
- Mass CEC Commonwealth Solar Database (Not updated since 3/12; likely redundant with SREC Database)
- Delaware SREC Long-term Contract Auction Results (No installed cost data available, only auction results)
- New Jersey EDC Long-term Contract Auction Results (No installed cost data available, only auction results, last auction was in 2011)

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

***Inverter warranty**: The solar CREST model has the ability to incorporate two capital expenditures during operations, which could be used to model inverter replacements. In response to recent data and stakeholder feedback, however, this analysis assumes that a 20-year inverter warranty is included in the total installed cost estimate. No additional inverter replacement costs are modeled.*

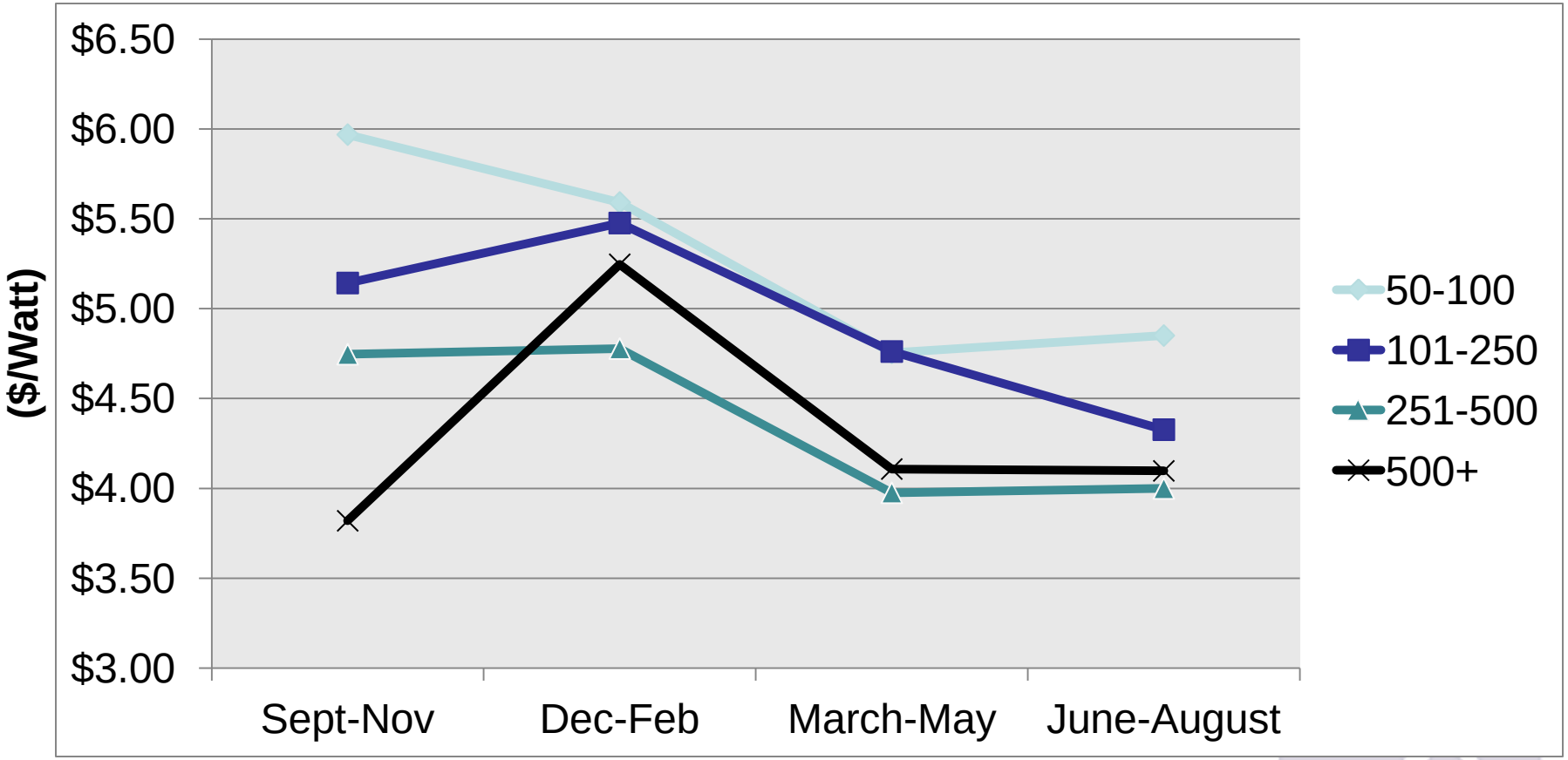
Mass SREC Database
(Sept 2011-August 2012)

Mass SREC Database - Average Installed Cost by Bin Quarter ($/Watt)				
Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	$5.97	$5.59	$4.75	$4.85
101-250	$5.14	$5.48	$4.76	$4.33
251-500	$4.75	$4.78	$3.98	$4.00
500+	$3.82	$5.25	$4.11	$4.10

Mass SREC Database - Average Installed Cost for Target Sizes by Quarter ($/Watt)				
Size Bin (kW)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	$5.05	$4.88	$4.35	$3.84
1000-2500		$5.75	$4.33	$3.98

Note: MA SREC data are backward looking, and generally represent the downward trending market. Where comparable, 2013 costs are expected to be lower.

Mass SREC Database Trend: Average Cost
(Sept 2011-August 2012)



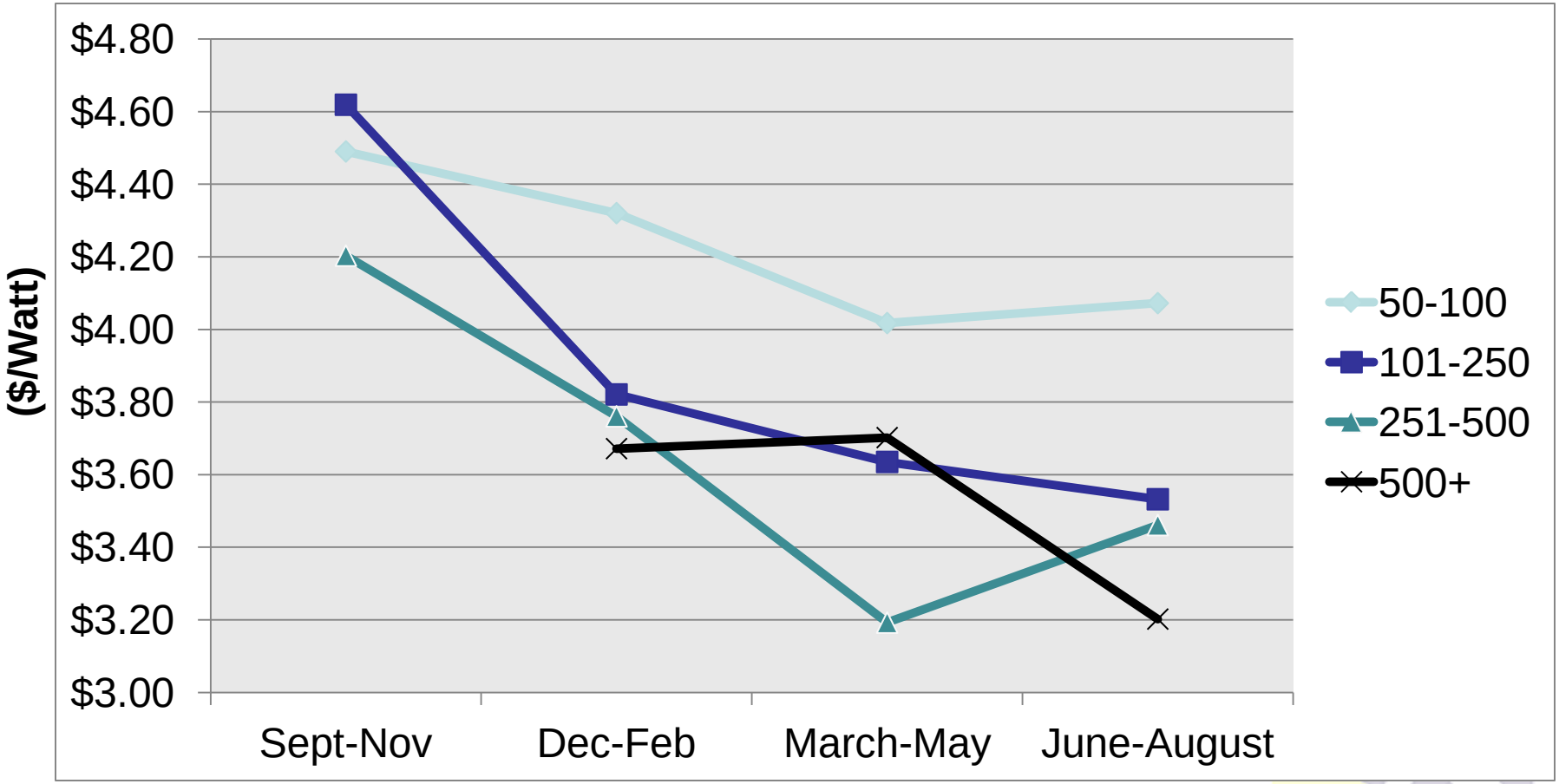
Mass SREC Database: Avg. - 1 Std. Deviation
(Sept 2011 – August 2012)

Mass SREC Database – Avg. Installed Cost minus 1 Std Dev by Qtr. ($/Watt)				
Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
50-100	$4.49	$4.32	$4.02	$4.07
101-250	$4.62	$3.82	$3.64	$3.53
251-500	$4.20	$3.76	$3.19	$3.46
500+		$3.67	$3.70	$3.20

Mass SREC Database – Avg. Inst. Cost minus 1 Std Dev for Target Sizes by Qtr. ($/Watt)				
Size Bin (kw)	Sept-Nov 2011	Dec-Feb	March-May 2012	June-August
350-650	$4.06	$3.99	$3.79	$2.88*
1000-2500		$4.08	$4.07	$3.13

* StdDev not meaningful due to small sample size.

Mass SREC Database Minus 1 Standard Deviation
(Sept 2011-August 2012)

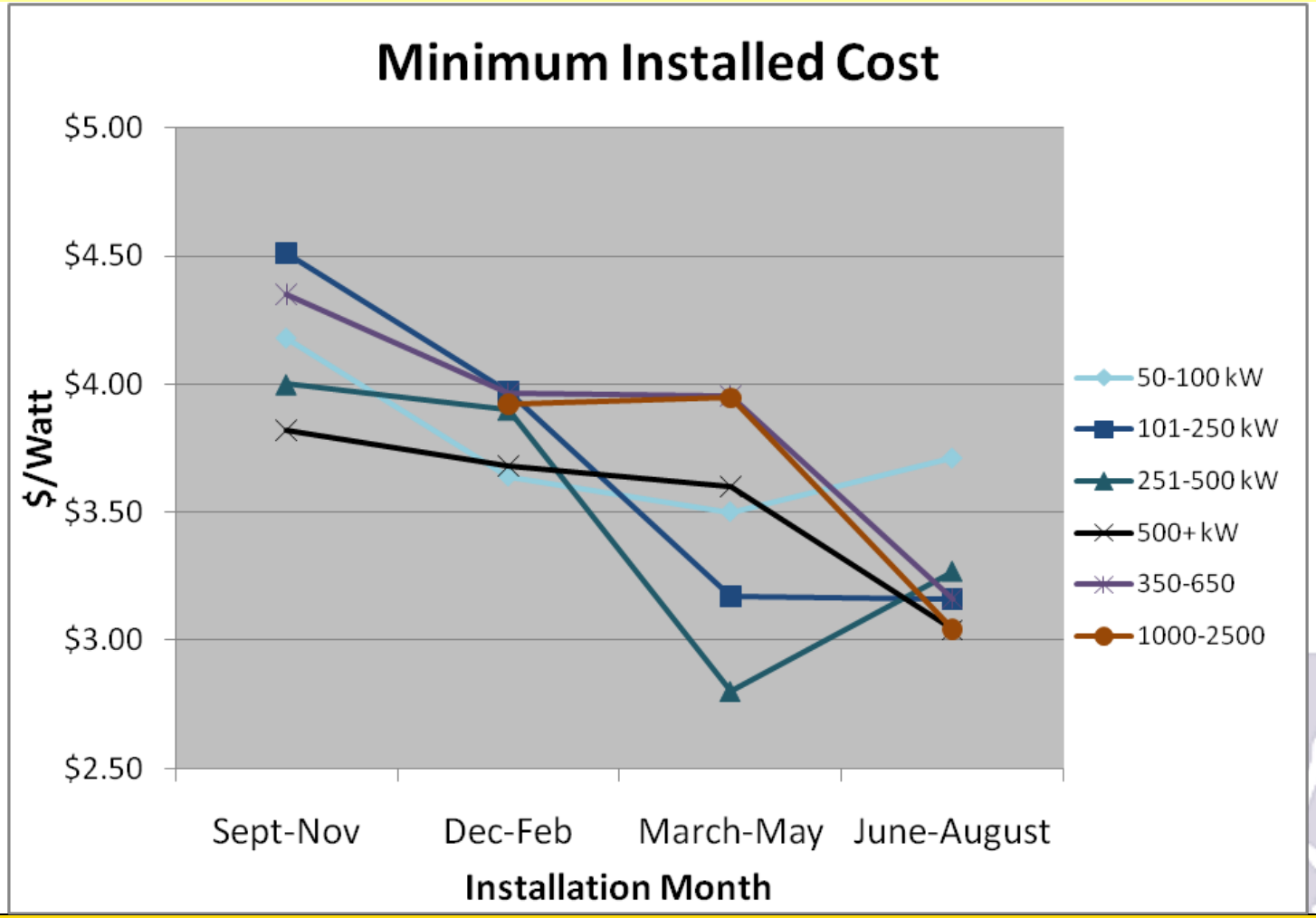


Mass SREC Database: Minimum Installed Cost in Each Bin

Bin	Installation Month (Range)	Min Installed Cost ($/Watt)
50-100	Sept-Nov	$4.18
	Dec-Feb	$3.64
	March-May	$3.50
	June-August	$3.71
101-250	Sept-Nov	$4.51
	Dec-Feb	$3.97
	March-May	$3.17
	June-August	$3.16
251-500	Sept-Nov	$4.00
	Dec-Feb	$3.90
	March-May	$2.80
	June-August	$3.27
500+	Sept-Nov	$3.82
	Dec-Feb	$3.68
	March-May	$3.60
	June-August	$3.04

Target Size	Installation Month (Range)	Min Installed Cost ($/Watt)
350-650	Sept-Nov	$4.35
	Dec-Feb	$3.96
	March-May	$3.95
	June-August	$3.16
1000-2500	Sept-Nov	
	Dec-Feb	$3.92
	March-May	$3.95
	June-August	$3.04

Mass SREC Database: Minimum Installed Cost in Each Bin



NREL National PV Cost Estimates

	Mean Costs ($/Watt)	St Dev	Mean – 1 St Dev
<10 kW	$4.78	$0.82	$3.96
10-100	$4.43	$0.54	$3.89
100-1000	$3.67	$0.67	$3.00
1-10MW	$3.38	$0.61	$2.77

Data from: *Distributed Generation Renewable Energy Estimate of Costs*
National Renewable Energy Laboratory, July 2012
http://www.nrel.gov/analysis/pdfs/2012_dg_icoe_data.pdf

Operation & Maintenance (O&M) Cost

Sources

- NREL National PV Cost Estimates

Project Size	Fixed O&M ($/kW-year)	O&M Std Dev
<10 kW	$29	$20
10-100 kW	$26	$19
100-1000 kW	$24	$13
1-10 MW	$22	$10

- MCG experience
- SEA experience
- Stakeholder DR

Mass SREC Database Descriptive Stats

Bin	Months	No.	Mean ($/Watt)	StdDev	Max	Min
50-100	Sept-Nov	6	$5.97	$1.48	$8.30	$4.18
	Dec-Feb	16	$5.59	$1.27	$7.83	$3.64
	March-May	9	$4.75	$0.74	$5.98	$3.50
	June-August	8	$4.85	$0.78	$5.97	$3.71
101-250	Sept-Nov	8	$5.14	$0.52	$5.75	$4.51
	Dec-Feb	22	$5.48	$1.66	$9.60	$3.97
	March-May	12	$4.76	$1.13	$7.07	$3.17
	June-August	8	$4.33	$0.79	$5.47	$3.16
251-500	Sept-Nov	7	$4.75	$0.54	$5.75	$4.00
	Dec-Feb	8	$4.78	$1.02	$6.78	$3.90
	March-May	5	$3.98	$0.78	$4.75	$2.80
	June-August	4	$4.00	$0.54	$4.52	$3.27
500+	Sept-Nov	1	$3.82	$0.00	$3.82	$3.82
	Dec-Feb	8	$5.25	$1.58	$7.80	$3.68
	March-May	6	$4.11	$0.41	$4.49	$3.60
	June-August	9	$4.10	$0.89	$5.76	$3.04
1000-2500	Sept-Nov	0				
	Dec-Feb	5	$5.75	$1.67	$7.80	$3.92
	March-May	4	$4.33	$0.26	$4.49	$3.95
	June-August	4	$3.98	$0.85	$5.05	$3.04

Interconnection

Details, Sources

- National Grid:
  - data from Standard Offer bids, plus
  - random sample of 21 MA & RI projects
- Stakeholder DR

Finance Structure & Costs of Debt and Equity

Details, Sources

- Stakeholder Data Request
- SEA Experience
- Model optimized based on avail cash flows

NOTE:

- Available data suggest a wider range of equity returns than returned in response to the data request, with much lower costs on the low-end of the range possible. Scale and ability to replicate are important factors.
- NREL Renewable Energy Finance Tracking Initiative, 2011:
  - Avg. equity return for solar < 1 MW (Q4'09-2011): developer equity ~12%; tax equity ~11%
    - Tax equity: 1st half 2011 ~7.8%; 2nd half 2011 ~10%
  - Solar developer return variance within 200 bps; tax equity w/in 70 bps
  - Trend is generally downward for both cash and tax equity.

Performance

Details, Sources

- PV Watts assumes no tracking, idealized orientation & tilt
- Stakeholder Data Request
- Inverter conversion factor based on data request and manufacturer input
- MA CEC PTS: actual historic production
- Same adjustments as made in 2011.

APPENDIX B - WIND

Additional Comments

Turbine Capacity Limit:

- Employing a capacity limit of ~2.0 MW would better reflect market conditions. During the last several years, the availability of 1,500 kW turbines has decreased in favor of machines in the 1.6, 1.65, 1.8 and 2 MW range.

Transaction Costs:

- Legal expenses are highly variable, and am important factor until all project processes and documents can be standardized. Legal fees for a project in SEMA were $400,000.

Financing Assumptions Post-PTC:

"We've not seen small [wind] projects pencil out without PTC for any reasonable return"

Behind the Meter

- *Thus far, 100 kW projects have been developed behind the retail meter, where the economics are more attractive due to net metering.*
- *Additional state-level grants have also played an important role for these projects.*

Capital Cost, Installed

(Includes soft costs & construction financing; excludes Interconnection)

Details, Sources

- Stakeholder DR
- SEA Experience
- Interviews

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

O&M Cost

Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience

Interconnection

Details, Sources

- Stakeholder DR
- National Grid: random sample of projects in RI & MA

Finance Structure & Costs of Debt and Equity

Details, Sources

- Stakeholder DR
- Interviews
- SEA Experience
- Model optimized based on available cash flows

Performance

Details, Sources

- Stakeholder DR
- SEA Experience
- MA CEC PTS
- Adjustment made for recent improvements in low wind-speed turbine performance, per SEA analysis.

APPENDIX C – ANAEROBIC DIGESTION

Details, Sources

Capital Cost, Installed (Includes soft costs & construction financing; excludes Interconnection)

- Stakeholder DR
- Interviews

Costs embedded in total installed cost estimates include:

***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

O&M

- Stakeholder DR

Interconnection

- Stakeholder DR

Finance Structure and Cost of Debt & Equity

- Stakeholder DR
- Model optimized based on available cash flows

Performance

- Stakeholder DR

Other Comments

- Costs and revenues (tipping fees) are highly variable and should be assessed on a per-project basis, especially related to digestate management.
- Also, there may be significant economies of scale. Inputs should be sought for each project.

Distributed Generations Contracts Program Update and Proposed 2013 Megawatt Allocation Plan

Office of Energy Resources

November 19, 2012

Updates

- Working with National Grid on (3) tentative enrollments in 2013 so that developers, businesses, and municipalities can plan accordingly.

- Questions/comments about a pending interconnection application after the statutory established deadlines for review, please email Office of Energy Resources. Include information on:

1. Project Location

2. Technology/System Size

3. Application Submittal/Paid For Date

4. National Grid Official Reviewing the Application

Updates

- Projects have been proposed in 17 of the 39 Cities and Towns in year 1 including:

  Jamestown, North Kingstown, Westerly, Hopkinton, Providence, West Warwick, Portsmouth, Lincoln, Cumberland, Cranston, Middletown, East Providence, North Smithfield, East Greenwich, West Greenwich, Bristol, and Central Falls.

Projects Awarded

338 Compass Circle North Kingstown

225 Dupont Drive, Providence

1060 West Main Road, Portsmouth

1 Ralco Way, Cumberland

1 John C. Dean Memorial Blvd, Cumberland

45 Bank St, Hopkinton

35 Martin St, Cumberland

28 Jacome Way, Middletown

Projects Awarded

87 Woodville Alton Rd, Hopkinton

100 Dupont Drive, Providence

Forbes Street East Providence

55 Clarkson Street, Providence

RI 9 James P. Murphy Dr, West Warwick

Rodman Lane, North Kingstown

179 Plain Meeting House Rd. West Greenwich

68 White Rock Road, Westerly

Projects Awarded

- Two (2) municipal projects have been awarded contracts.
- Fourteen (14) private projects have been awarded contracts.

Distributed Generation Contracts Program - Costs/Economic Data

- The Office of Energy Resources is reviewing the DGC application data provided by National Grid and will make information public when review is complete.

- Developers: please make sure all DGC applications submitted for the 2013 program are completely filled out. Incomplete applications slow the process down.

2013 Distributed Generation Contracts Program

DGC Law Requirements

- "**Small distributed generation project**" - a distributed generation project that has a nameplate capacity no larger than:
  - Solar: five hundred kilowatts (500 KW);
  - Wind: one and one-half megawatts (1.5 MW).

- For technologies other than solar and wind, the board shall set the nameplate capacity size limits, **<u>but such limits may not exceed one megawatt.</u>**

- The board may lower the nameplate capacity from year to year for any of these categories, but may not increase the capacity beyond what is specified in this definition.

DGC Law Requirements

- "**Large distributed generation project**" - a distributed generation project that has a nameplate capacity that exceeds the size of a small distributed generation project in a given year, but is no greater than five megawatts (5 MW) nameplate capacity.

- Except for 2011, **no enrollment period shall seek to enroll more than one-third (1/3) of the annual goal** for the distribution company for large distributed generation projects.

Megawatts Available in 2013

- The DGC Program will have 13.8 MW available in 2013 (including 3.8 MW from the 2012 DGC program).

- Under the DGC law the maximum allocation available for large DG projects is 4.554 MW.

Megawatts Available in 2013

- The Office of Energy Resources proposes the following carve-outs for the large and small DGC classes:

  - Large DGC Projects: 4.00 MW

  - Small DGC Projects: 9.8 MW

- There will be 4.6 MW for each enrollment in 2013.

- There was 5.0 MW available for the enrollments in 2012.

History
2012 Megawatt Allocation Plan – Scenario 1

Technology	Size	Target
Solar-PV	10-150 kW	0.5 kW
Solar-PV	151-500 kW	1 MW
Solar-PV	501-5000 kW	2 MW
Wind	1.5 MW	1.5 MW

History
2012 Megawatt Allocation Plan – Scenario 2

Technology	Size	Target
Solar PV	10-150 KW	1 MW
Solar PV	151-500 KW	1.5 MW
Solar PV	501-5000 KW	2.5 MW

2013 Proposed Megawatt Allocation Plans

Scenario - 1

Small DGC Program	
Technology	**kW/MW Available**
Wind: 50 kW - 1.5 MW	1.5 MW
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	250 kW
Small Solar PV: 251-500 kW	750 kW
Anaerobic Digestion	500 kW
Large DGC Program	
Solar PV/Anaerobic Digestion: 501 kW – 1.3 MW	1.3 MW
Total MW	**4.6 MW**

Recommended 2013 MW carve-out allocations if National Grid receives applications from all of the eligible technologies in any of the three (3) rounds of the DGC program.

Scenario - 2

Small DGC Program	
Technology	**kW/MW Available**
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	500 kW
Small Solar PV: 251-500 kW	1.5 MW
Anaerobic Digestion	1 MW
Large DGC Program	
Solar PV/Anaerobic Digestion: 501 kW – 1.3 MW	1.3 MW
Total MW	**4.6 MW**

Recommended 2013 MW carve-out allocations if National Grid receives no wind turbine applications during any of the three (3) rounds of the DGC program.

Scenario - 3

Small DGC Program	
Technology	**kW/MW Available**
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	1 MW
Small Solar PV: 251-500 kW	2 MW
Large DGC Program	
Solar PV: 501 kW – 1.3 MW	1.3 MW
Total MW	**4.6 MW**

Recommended 2013 MW carve-out allocations if National Grid receives no wind turbine or anaerobic digestion applications during any of the three (3) rounds of the DGC program.

Questions/Comments

2013 Distributed Generation Contracts Program – Recommended Ceiling Prices, Target Classes, and Enrollment Plan

Office of Energy Resources

November 28, 2012

2013 Recommended Ceiling Prices

Technology, sub-class	2011/2012 Ceiling Price (¢/kWh)	2013 Proposed Ceiling Price (¢/kWh) w/PTC	Net Change* btw previous and proposed Ceiling Prices	2013 Proposed Ceiling Price (¢/kWh) w/o PTC
Solar, 500 kW+	**28.95**	**24.95**	**-14%**	**N/A**
Solar, 251 – 499 kW	**31.60**	**28.40**	**-10%**	**N/A**
Solar, 101 – 250 kW	**33.35 (for 150 kW)**	**28.80**	**-14%**	**N/A**
Solar, 50 – 100 kW	**33.35 (for 150 kW)**	**29.95**	**-10%**	**N/A**
Wind, 1 – 1.5 MW	**13.35**	**16.80**	**+26%**	**18.60**
Wind, 400 – 999 kW	**N/A**	**18.15**	**N/A**	**19.95**
Wind, 90 – 100 kW	**N/A**	**24.65**	**N/A**	**N/A**
AD, 400 – 500 kW and 501 kW – 1 MW	**N/A**	**18.55**	**N/A**	**19.55**
Hydro, 500 kW – 1 MW	**N/A**	**17.90**	**N/A**	**18.85**

2013 Recommended Target Classes

Technology, sub class	Eligible Size Range	Standard Size for Modeling Ceiling Price
Solar, Large	501 kW and above	1.5 MW
Solar, Medium 2	251 – 500 kW	500 kW
Solar, Medium 1	101 – 250 kW	250 kW
Solar, Small	50 – 100 kW	100 kW
Wind, Large	1.0 MW – 1.5 MW	1.5 MW
Wind, Medium	200 kW – 999 kW	750 kW
Wind, Small	50 – 100 kW	100 kW
Small Anaerobic Digestion	400- 500 kW	500 kW
Large Anaerobic Digestion	501 kW and above	500 kW
Hydroelectric*	500 kW – 1.0 MW	1.0 MW

***There will be no MW allocation for hydropower in 2013, but the OER wanted to get a ceiling price established to begin discussions about potentially having hydropower projects participate in the 2014 program.**

2013 Recommended Enrollment Plan

Small DGSC Program	
Technology	**kW/MW Available**
Wind: 50 kW - 1.5 MW	1.5 MW
Small Solar PV: 50-100 kW	300 kW
Small Solar PV: 101-250 kW	250 kW
Small Solar PV: 251-500 kW	750 kW
Anaerobic Digestion: 400–500 kW	500 kW
Large DGSC Program	
Solar PV/Anaerobic Digestion: 501 kW-1.3 MW	1.3 MW
Total MW	**4.6 MW**

2013 Recommended Enrollment Plan

- The OER determined after public and written comments that having one enrollment plan will provide a predictable program for businesses, municipalities, and renewable energy developers to participate in.
- The majority of the megawatt (MW) allocations would remain with the same technology target classes for the year.
- The only exception to this would apply to the 50-100 kilowatt (kW) solar target class for each enrollment.
- If 50-100 kW solar project applications aren't submitted for that target class in each of the enrollments, then National Grid could use those kW allocations toward the large DGSC technology target class.

2013 Recommended Enrollment Plan

- The enrollment plan will allow municipal and business sites the proper time to develop their projects, without having to rush into a enrollment period.
- The enrollment plan will likely lead to an overall reduction in the cost of the program, when compared to the 2012 program.
- Any MW remaining at the end of the year would be placed into the 2014 program.