EXHIBIT 4

1. **DGSC Board Meeting - July 18, 2013**

    - Distributed Generation Contracts Program Updates: OER Presentation

2. **DGSC Board Meeting - August 19, 2013**

    - RI Renewable Distributed Generation Program Results: National Grid Presentation

3. **DGSC Board Meeting - October 8, 2013**

    - Distributed Generation Contracts Program Updates: OER Presentation
    - SEA CREST Model Presentation

4. **DGSC/OER Public Meeting - October 22, 2013**

    - Preliminary Input Assumptions & Modeling Results for 2014 Ceiling Price Review: SEA Presentation
    - Distributed Generation Contracts Program – Updates: OER Presentation

5. **DGSC/OER Public Meeting - November 7, 2013**

    - RI Interconnection Standard Process: National Grid Presentation
    - 2014 Distributed Generation Contracts Program – Suggested Megawatt Allocation Plan: OER Presentation

6. **DGSC/OER Public Meeting - November 14, 2013**

    - 2nd Draft Proposed 2014 Ceiling Prices: SEA Presentation

7. **DGSC/OER Public Meeting - November 27, 2013**

    - 2014 Distributed Generation Contracts Program – Recommended Megawatt Allocation Plan: OER Presentation

8. **DGSC Board Meeting - December 2, 2013**

    - Proposed Final 2014 Analysis & Data Submittal to DG Board: SEA Presentation
    - 2014 Distributed Generation Contracts Program – Summary and Recommendations: OER Presentation

Distributed Generation Contracts Board Meeting

Thursday, July 18, 2013

Distributed Generation Contracts Board Meeting Agenda

- Introduction of Board Members
- Background on the DG Program
- 2013 DG Legislative Changes
- Plans/Next Steps for the 2014 DG Program

DG Program Background

- The forty (40) megawatt (MW) DG program became law in June 2011. The DG program launched in December 2011, and is tentatively scheduled to end in December 2014.

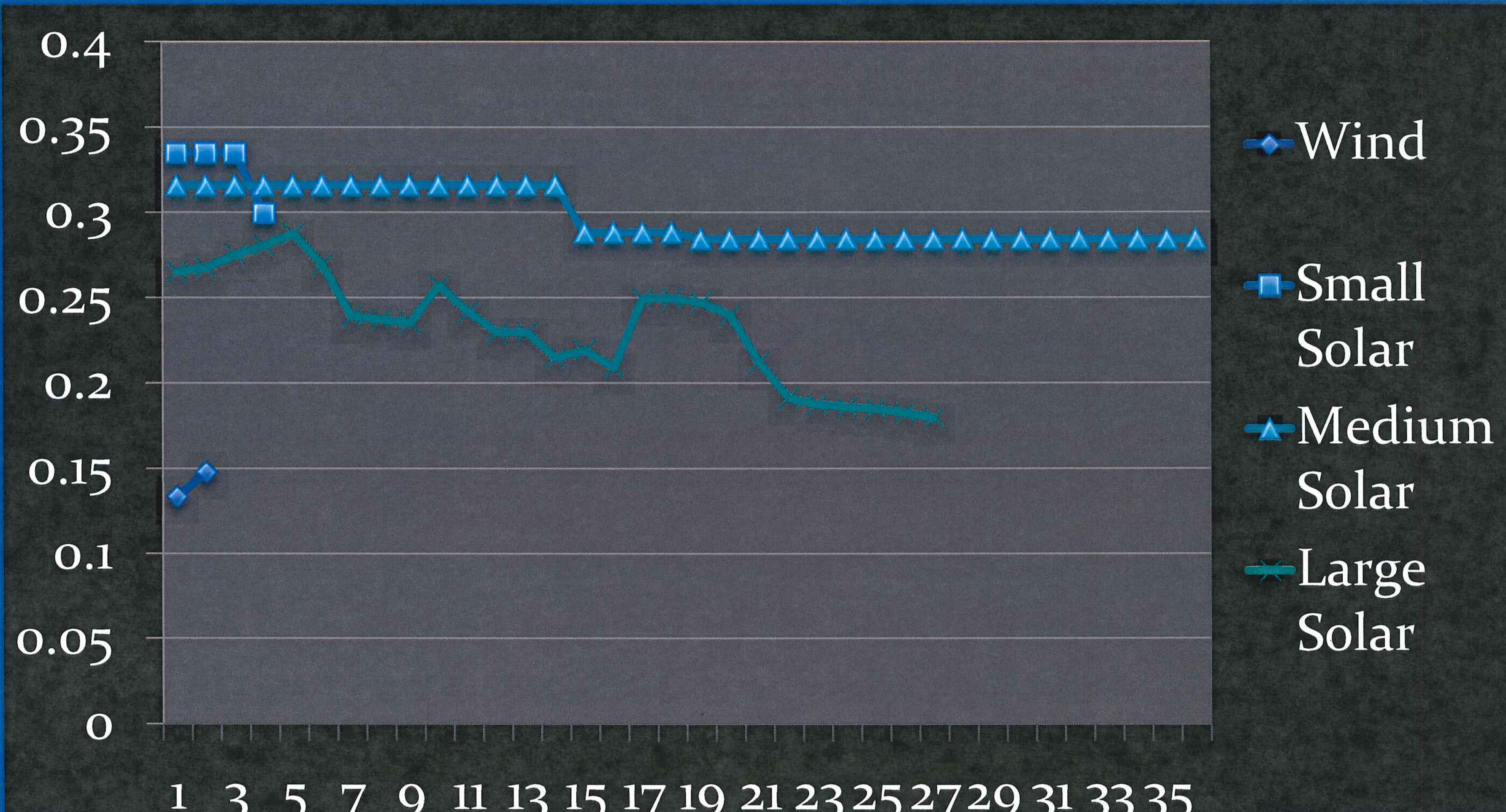
- There are up to three (3) enrollments per year. The annual MW allocation plan is as follows: 2011- 5MW, 2012-15 MW, 2013-10 MW and 2014-10 MW.

- DG projects are scheduled to be built in twelve (12) municipalities, including the following: Providence, Jamestown, Middletown, North Smithfield, North Kingstown, Woonsocket, Cranston, West Greenwich, Hopkinton, West Warwick, Cumberland, Portsmouth

- DG projects have been proposed in twenty-four (24) cities and towns.

- There have been two (2) enrollments in 2013. The first was in March and the second was in June. The final enrollment will be in September.

DG Ceiling Price History



The overall trend has seen the prices for DG projects decrease over the past two (2) years, which was one of the objectives of the law. Anticipate the ceiling prices to decrease in 2014, with the recent changes to the law.

Changes to the DG Law

- The OER introduced DG legislation this session, which was passed by the General Assembly and signed by Governor Chafee on July 11th.
- The legislation made adjustments and improvements to the DG Program, including the following:
- Competitive bidding amongst the eligible small DG projects.
- Allows small-scale hydropower to participate, by allowing it to become operational within forty-eight (48) months after being awarded a DG contract.
- Upon request by a renewable energy developer, National Grid will need to provide written feedback on why their DG application was not approved.
- Reduces the eligible DG system size from 5MW to 3MW.

Changes to the DG Law

- Allows any unused MW (projects that fail to be completed) to be used in future years, until those MW become operational.

- Removes the performance guarantee requirement that the DG system needs to produce one-hundred (100) percent of what was proposed in the DG application. Requires that the DG system produce ninety (90) percent of what is proposed in the DG application.

- Extended the deadline for the remaining MW with the Long-Term Contracting law by one year, to be reviewed in coordination with the DG program during the 2014 legislative session by the stakeholders, House and Senate.

- The OER shall submit to the Governor, Senate President, and the Speaker of the House by January 15, 2014 an annual jobs, economic and environmental impact study.

2014 DG Program – Next Steps

- Due to the uncertainty of whether the DG Board would be formed before the end of the 2013 legislative session, the OER started to proceed as it did in past years, in beginning to prepare for the 2014 DG program.

- The OER would like to proceed with the same process that was used successfully in 2012, with the approval from the DG Board.

2014 DG Program – Next Steps

- The OER is recommending to use the same consultant that developed the DG ceiling prices in 2011, 2012 and 2013.

- The OER is recommending an extension in submitting the 2014 DG ceiling prices and program plan until December 15th. The DG program plan is currently due to the Public Utility Commission (PUC) by October 15th.

- This specific requests is made for the following reasons:

  1.) Due to the last three (3) years of uncertainty with the federal government on renewable energy incentives being extended or not.

  2.) Allows the 2014 DG program to factor in possible MW from solar projects awarded DG contracts in April 2012 that may not get built.

  3.) Allows proper time to review the results of the 2013 DG program and the MW that may be available after the September enrollment.

2014 DG Program – Next Steps

- The OER is respectfully requesting that the DG Board consider a vote on the following matters at the next meeting in August:

- Use the consultant that developed the DG ceiling prices in 2011, 2012 and 2013.

- An extension on the submittal date for the 2014 DG ceiling prices and program plan to the PUC.

Questions/Comments

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RI Renewable Distributed Generation Program

Presentation to RI DG Board
August 19, 2013

Distributed Generation Standard Contracts Act[1]

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- Requires 10% of the 90 MW Long Term contract capacity be Distributed Generation, inclusive of solar capacity.
- Three Open Enrollments per year for a total of 40 MW nameplate over 4 years
  - By December 30, 2011: 5 MW (nameplate)
  - By December 30, 2012: an aggregate of 20 MW
  - By December 30, 2013: an aggregate of 30 MW
  - By December 30, 2014: an aggregate of 40 MW
- 2011-2012 complete[2], reached aggregate 15.2 MW total with 15 Standard Contracts

Class	Eligible Sizes	2011 & 2012 Ceiling Price ($/MWh)
Wind	Up to 1.5 MW	$ 133.50
Solar – Small	10 – 150 kW DC	$ 333.50
Solar – Medium	151 – 500 kW DC	$ 316.00
Solar – Large	501 – 5000 kW DC	$ 289.50

- 2013-1 Open Enrollment complete, reached additional 3.7 MW with 7 Standard Contracts

[1]Effective June 29, 2011, amended July 11, 2013

[2]RI The RI PUC approved a motion by the RI OER to cancel the third 2012 Open Enrollment and reallocate the remaining 2012 capacity to the 2013 program.

2013 RI DG Program

4,600 kW Total Target each enrollment

Class (Eligible Nameplate)	Enrollment Target Nameplate (kW)	2013 Ceiling Price (cents/kWh)
Wind (50-1500 kW) (50-100 kW) (200-999 kW) (1,000-1,500 kW)	1,500	 24.65 16.20 14.80
Solar (50-100 kW DC)	300	29.95
Solar (101-250 kW DC)	250	28.80
Solar (251-500 kW DC)	750	28.40
Anaerobic Digestion (400-500 kW DC)	500	18.55
Solar/Anaerobic Digestion (501-5000 kW DC)*	1,300	24.95 / 18.55

*Any unused allocation from a specific class shall roll over into the next open enrollments for that same class; with exception to the Small Solar (50 – 100 kW). Any unused allocation from the Small Solar (50 – 100kW) class is to be added to the Large Solar PV/Anaerobic Digestion class in future enrollments.

Legislative Amendments to DG Standard Contracts Act

- Act signed into law effective July 11, 2013
- Now requires Small DG Projects to be bid with competitive pricing
  - Benefit to all customers through lower contract pricing
- Maximum size of DG Projects reduced from 5 MW to 3 MW
- Act now includes progress reporting provisions and changes to the generation "output demonstration" provisions

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Revised 2nd 2013 RI DG Open Enrollment

- Due to changes in Act the 2nd RI DG Open Enrollment was put on hold
- Revisions to DG Standard Contract Enrollment Applications, Process Rules and DG Standard Contracts filed with RI PUC
- Upon approval by RI PUC, Revised 2nd 2013 RI DG Open Enrollment will be re-opened for those “Small” Project bidders from 2nd OE to update their applications with competitive pricing proposals
- Evaluations of revised proposals and awards to both “Small” and “Large” projects to occur thereafter

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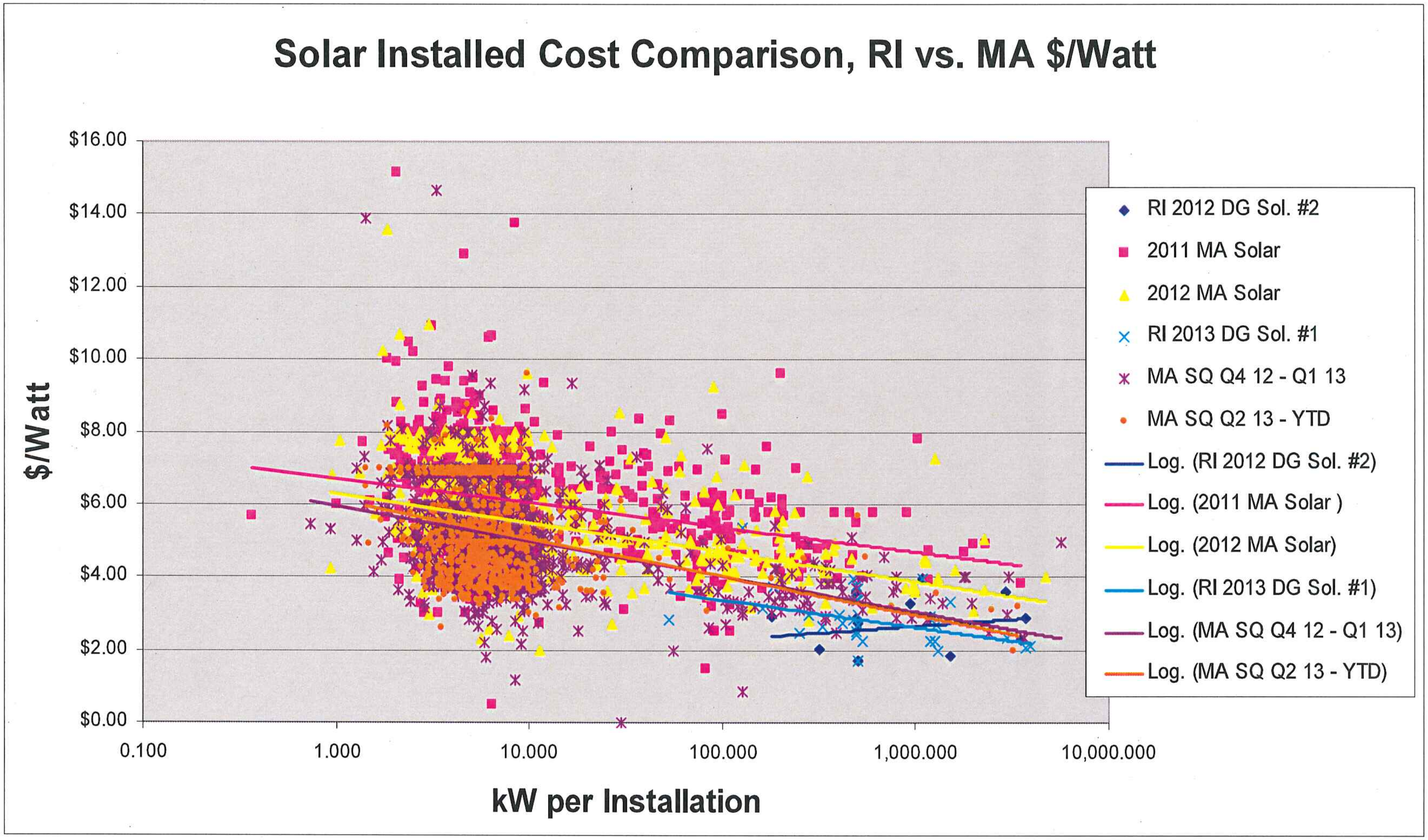
RI DG Program installed costs are lower than in MA



Note: The construction cost data used for this chart was provided by projects/applicants in the pre-construction phase and may not represent actual construction costs. This information has not been verified by National Grid and is intended only for discussion purposes.

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Standard Contracts

- Commercial Operation – 20 months
  - Interconnection
  - Output Demonstration – 18 months
  - Eligible Renewable Energy Resource
  - ISO-NE and GIS
  - FERC

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APPENDIX

2011/2012 RI DG Enrollment Targets and Ceiling Prices

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- With Wind, 5 MW Target

Class	Eligible Sizes (Nameplate)	Enrollment Target Nameplate (kW)	2011/2012 Ceiling Price (cents/kWh)
"Small" Solar	(10-150 kW DC)	500	33.35
"Medium" Solar	(151-500 kW DC)	1,000	31.60
Large Solar	(501-5,000 kW DC)	2,000	28.95
Wind	(1,500 kW)	1,500	13.35

- Without Wind, 5 MW Target

Class	Eligible Sizes (Nameplate)	Enrollment Target Nameplate (kW)	2011/2012 Ceiling Price (cents/kWh)
"Small" Solar	(10-150 kW DC)	1,000 kW	33.35
"Medium" Solar	(151-500 kW DC)	1,500	31.60
Large Solar	(501-5,000 kW DC)	2,500	28.95

*DGSC Act defines Small Solar projects as projects less than 500 kW nameplate.

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Progress to-date

- 2011 Program Year - By December 30, 2011: a minimum of 5 MW nameplate
  - 2011 Open Enrollment - Reached 5 MW Target with 4 projects:

Class	Project Nameplate (kW)	Contract Price (cents/kWh)
Medium Solar (151-500 kW DC)	500	31.60
Large Solar (501-5,000 kW DC)	1,000	26.50
Large Solar (501-5,000 kW DC)	2,000	27.50
Wind (1,500 kW)	1,500	13.35

- 2012 Program Year
  - 5 MW (or 5,000 kW) per enrollment
  - First 2012 Open Enrollment - Reached 5 MW Target with 2 projects, for a total of 6,050 kW:

Class	Project Nameplate (kW)	Contract Price (cents/kWh)
Large Solar (501-5,000 kW DC)	2,340	23.699
Large Solar (501-5,000 kW DC)	3,710	23.90

Progress to-date

- Second 2012 Open Enrollment - Reached target with 10 projects, for a total of 5,127 kW

Class	Nameplate (kW)	Contract Price (cents/kWh)
Small Solar (10-150 kW DC)	149	33.35
Medium Solar (151-500 kW DC)	181	31.60
Medium Solar (151-500 kW DC)	300	31.60
Medium Solar (151-500 kW DC)	498	31.60
Medium Solar (151-500 kW DC)	499	31.60
Medium Solar (151-500 kW DC)	500	31.60
Medium Solar (151-500 kW DC)	500	31.60
Medium Solar (151-500 kW DC)	500	31.60
Medium Solar (151-500 kW DC)	500	31.60
Large Solar (501-5,000 kW DC)	1,500	20.90

Progress to-date

- First 2013 Open Enrollment – Executed Contracts on 7 projects, for a total of 3,684 kW

Class	Nameplate (kW)	Contract Price (cents/kWh)
Wind (1,000-1,500 kW DC)	1,500	14.80
Small Solar (50-150 kW DC)	53	29.95
Small Solar (50-150 kW DC)	128	28.80
Medium Solar (151-500 kW DC)	182	28.80
Medium Solar (151-500 kW DC)	331	28.40
Medium Solar (151-500 kW DC)	406	28.40
Large Solar (501-5000 kW DC)	1,084	18.49
Total:	3,684	

RI DG Standard Contracts

RI DG Standard Contracts	Nameplate Capacity (kW)	Contract Price (cents/kWh)
2011 RIDG - CED, Plain Meeting House Power	2,000	27.50
2011 RIDG - ACP Land, 28 Jacome Way	500	31.60
2011 RIDG - Wind Energy Development, North Kingstown Green	1,500	13.35
2012-1 RIDG - Forbes Street Solar	3,700	23.90
2012-1 RIDG - West Davisville Solar, 338 Compass Circle	2,300	23.70
2012-2 RIDG - Soltas 100 Dupont	1,500	20.90
2012-2 RIDG - Altus Comtram Cable Plant	499	31.60
2012-2 RIDG - CoxCom CCI NE 181 kW	181	31.60
2012-2 RIDG - Soltas 0 Martin	500	31.60
2012-2 RIDG - Soltas 225 Dupont	300	31.60
2012-2 RIDG - Soltas 45 Bank	500	31.60
2012-2 RIDG - Soltas 35 Martin	500	31.60
2012-2 RIDG - Soltas 87 Woodville Alton	500	31.60
2012-2 RIDG - CoxCom CCI NE 500 kW	498	31.60
2012-2 RIDG - Venti Wind Bonollo's Solar	149	33.35
2013-1 RIDG - WED Coventry One	1,500	14.80
2013-1 RIDG - Brickle Group Solar	1,084	18.49
2013-1 RIDG - Gannon & Scott Solar	406	28.40
2013-1 RIDG - All American Foods	331	28.40
2013-1 RIDG - TEAM Solar	182	28.80
2013-1 RIDG - CMS Solar	128	28.80
2013-1 RIDG - Newport Vineyards Solar	53	29.95
Total:	18,811	

Distributed Generation Contracts Program - Updates

Office of Energy Resources

Tuesday, October 8, 2013

STATE OF RHODE ISLAND
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ENERGY RESOURCES

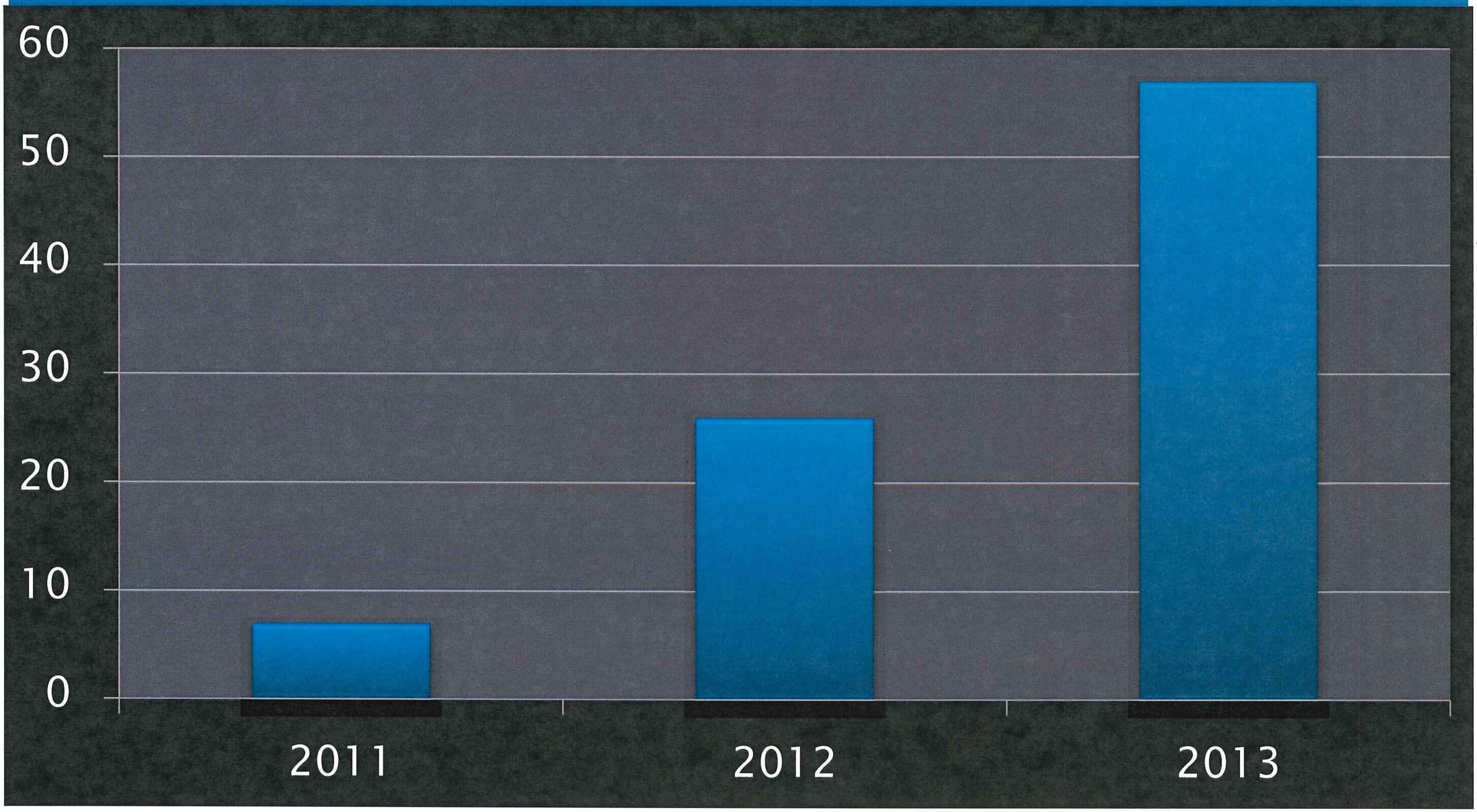
Results

- Twenty-two (22) applications submitted in the second enrollment.
- There were 15.560 MW of proposals.
- DG projects were proposed in fourteen (14) municipalities.
- Five (5) projects were awarded DG contracts located in Johnston, Warren, North Kingstown, Glocester and Pawtucket

Projects Selected

- Solar - 92 kW, 281 kW, 480 kW and 1.7 MW systems
- The 2nd round experienced ceiling price drops between 27.5% and 45% for the medium scale solar projects, and almost 30% for the large scale solar project.
- Anaerobic Digestion - 500 kW system
- All of the awarded DG projects must be operational by April 2015.

Application History



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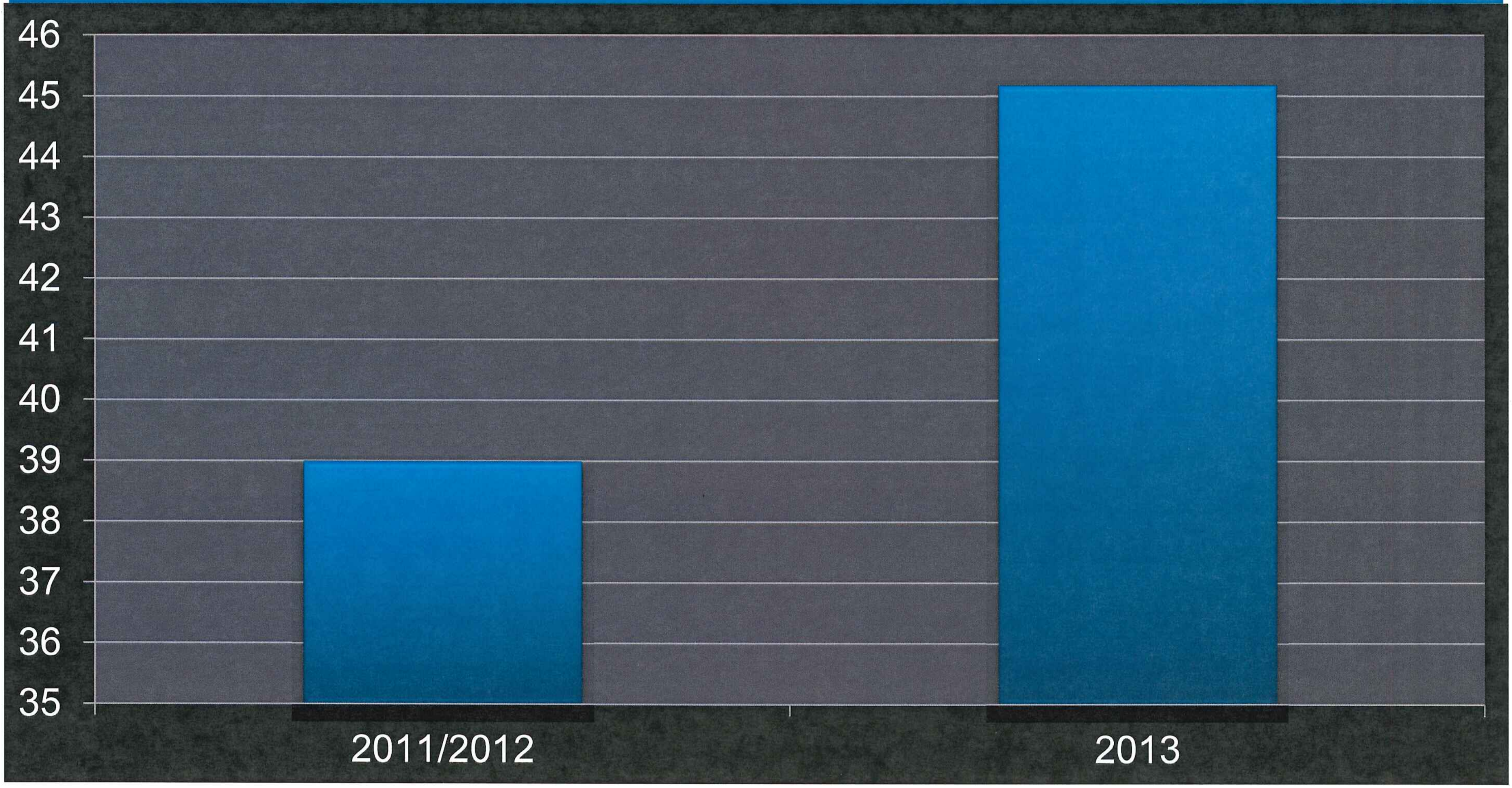
MW Application History



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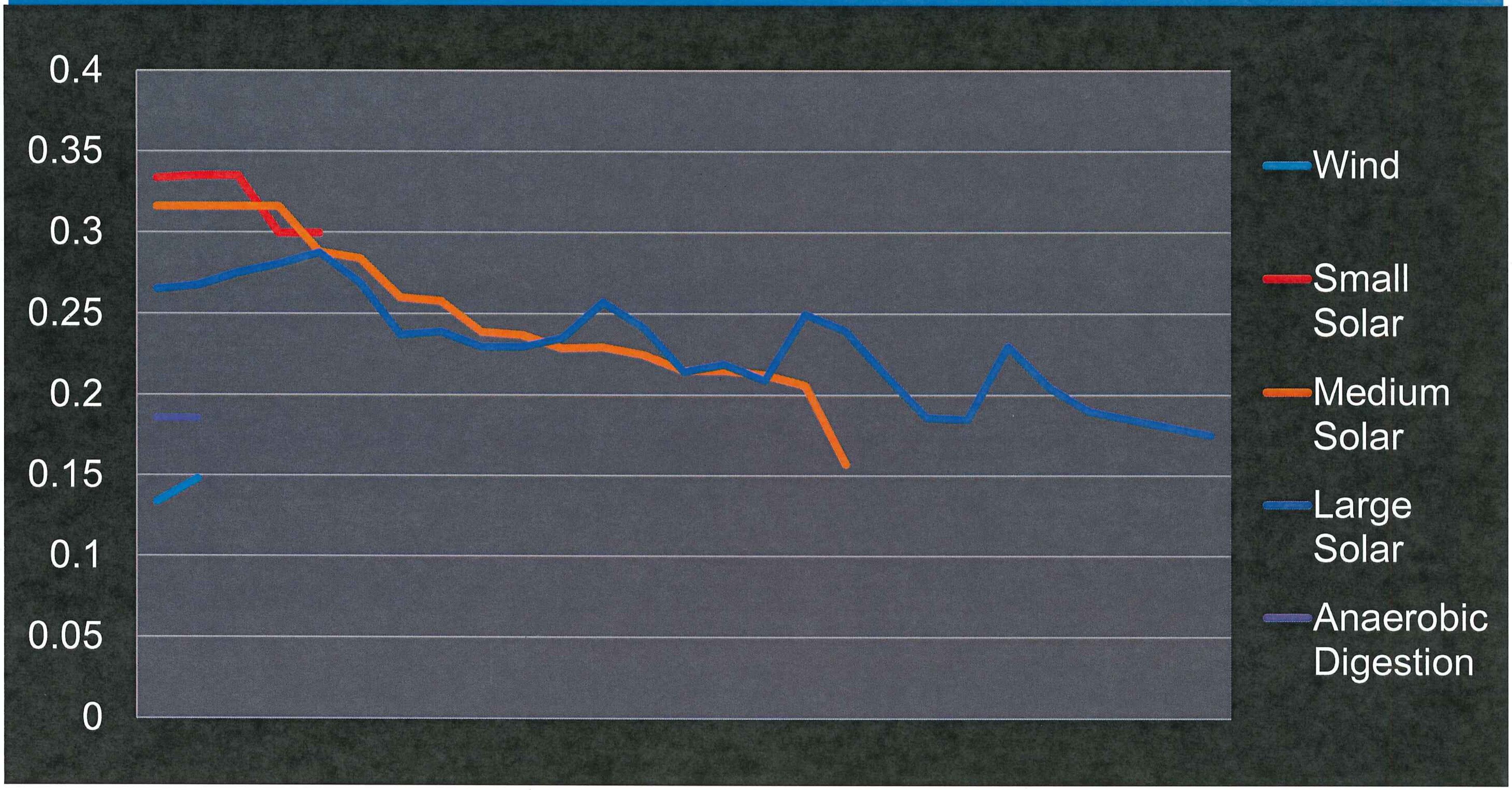
Application Ceiling Price History December 2011 – September 2013



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OFFICE OF ENERGY RESOURCES

These ceiling prices reflect the changes to the DG law from the 2013 legislation.

Proposed Project Locations

- DG projects have been proposed in the following municipalities:

- North Smithfield, Glocester , Bristol, Middletown, West Warwick, Bradford, Richmond, East Greenwich, North Kingstown, Hopkinton, Cumberland, Providence, Cranston, Lincoln, Richmond, Warwick, Pawtucket, Woonsocket, Warren, Coventry, Jamestown, Johnston, East Providence, Central Falls, West Greenwich, Westerly, Warren and Portsmouth

- The state has now seen DG projects proposed in 28 of the 39 Cities and Towns.

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Project Locations

- DG projects are scheduled to be built, or have been installed in the following fifteen (15) municipalities:
- Providence, Glocester, Jamestown, Middletown, North Smithfield, North Kingstown, Woonsocket, Cranston, West Greenwich, Hopkinton, West Warwick, Cumberland, Portsmouth, Warren and Pawtucket

Contract Results

- Twenty-seven (27) DG contracts awarded
- 2 Wind Turbine projects
- 3 Small Solar projects
- 16 Medium Solar projects
- 6 Large Solar projects
- 1 Anaerobic Digestion project
- 21.413 MW have been awarded from the five (5) enrollments.

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DG Installations

Location	Technology/ System Size	Operational or Contract Deadline
179 Plain Meeting House Rd. West Greenwich	Solar – 2 MW	Operational
Thornton Way. North Kingstown	Wind – 1.5 MW	Operational
28 Jacome Way. Middletown	Solar – 500 kW	Operational
Forbes St. East Providence	Solar – 3.71 MW	October 2013
228 Compass Circle. North Kingstown	Solar – 2.71 MW	Operational
55 Clarkson St. Providence	Solar – 149 kW	January 2014
9 James P. Murphy Dr. West Warwick	Solar – 181 kW	January 2014
225 Dupont Dr. Providence	Solar – 300 kW	January 2014

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Location	Technology/ System Size	Operational or Contract Deadline
1060 West Main Rd. Portsmouth	Solar – 498 kW	January 2014
1 Ralco Way. Cumberland	Solar – 499 kW	January 2014
1 John C. Dean Memorial Blvd. Cumberland	Solar – 500 kW	January 2014
45 Bank St. Hopkinton	Solar – 500 kW	January 2014
35 Martin St. Cumberland	Solar – 500kW	January 2014
87 Woodville Alton Rd. Hopkinton	Solar – 500 kW	January 2014
100 Dupont Dr. Providence	Solar – 1.5 MW	January 2014

Location	Technology/ System Size	Operational or Contract Deadline
909 East Main Rd. Middletown	Solar – 53 kW	September 2014
260 Conanicus Ave. Jamestown	Solar – 128 kW	September 2014
811 Park East Dr. Woonsocket	Solar – 182 kW	September 2014
65 All American Way North Kingston	Solar – 331 kW	September 2014
45 Sharpe Dr. Cranston	Solar – 406 kW	September 2014
582 Great Rd. North Smithfield	Solar – 1.084 MW	September 2014
210 Piggy Lane Coventry	Wind – 1.5 MW	September 2014

3rd Enrollment
October 28th – November 8th

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Technology Class	Available Nameplate Capacity	Eligible System Sizes	2013 Ceiling Price (cents/kWh) Limits
Wind	3.0 MW	50-100 kW, 200-999 kW, 1.0-1.5 MW	24.65, 16.20, 14.80
Small Solar	300 kW	50-100 kW	29.95
Solar	440 kW	101-250 kW	28.8
Solar	752 kW	251-500 kW	28.4
Anaerobic Digestion	1.0 MW	400-500 kW	18.55
Large Solar/Anaerobic Digestion	1.571 MW	501 kW – 3MW	24.95 / 18.55

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No DG applications can submit beyond the approved system sizes for each technology class.

Economic and Jobs Impact Study

- The OER and the Economic Development Corporation secured funding through the Renewable Energy Fund (REF) in September to perform an Economic and Jobs Impact Study on the DG and REF programs.

- The RFP will be released this month. The study will be completed and provided to the Governor and General Assembly by March 2014.

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DG Forecast Working Group

- ISO-NE launched a DG Forecast Working Group with the Northeast State Energy Offices, to identify and provide all of the DG installations and projects scheduled to become operational.

- The DG data will assist ISO-NE in forecasting what types of DG technologies will becoming online, to prepare for both the challenges and benefits of DG deployment in New England, including deferring upgrades or new transmission.

- The State Energy Offices are requesting that ISO-NE forecast the DG installations into their 2014 forecasting plans for energy supplies and possible plans for upgrades or new transmission.

Questions/Comments

Chris Kearns

Chief, Program Development

christopher.kearns@energy.ri.gov

401-574-9113

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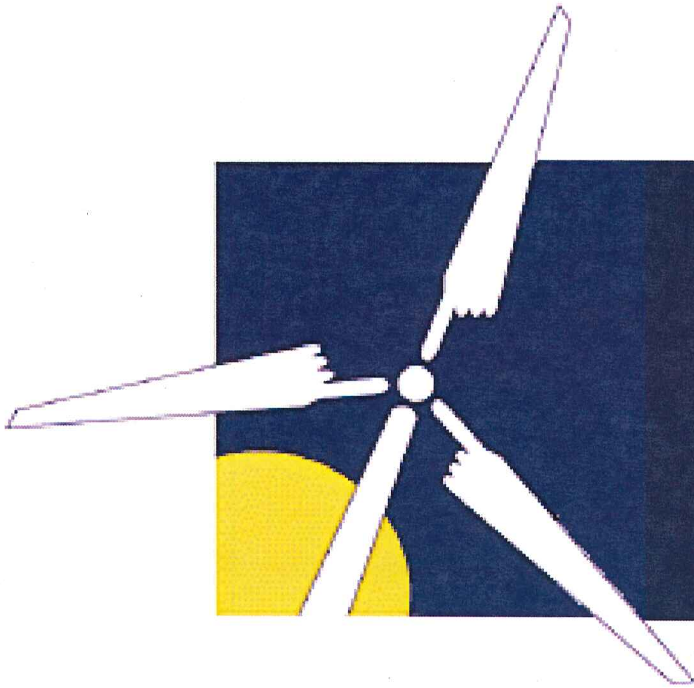

Cost of Renewable Energy Spreadsheet Tool (CREST)

An Introduction & Primer

Jason Gifford
Sustainable Energy Advantage, LLC

October 8, 2013

Renewable Energy Cost Modeling

Project Objectives:

- Create a toolkit for cost-based rate-setting in the US
  - Report, Models, User Manual
- CREST models:
  - A cost-of-energy analysis tool intended to assist policy makers considering cost-based renewable energy incentive policy.
  - Models: Solar, Wind, Anaerobic Digester, Geothermal, Fuel Cell
- CREST models (and Report and User Manuals) are publicly available at:

  http://financere.nrel.gov/finance/content/crest-model

  or Google "CREST model".

Project Team

- National Renewable Energy Laboratory (NREL)
  - Exeter Associates, Inc.
    - Sustainable Energy Advantage (SEA)
    - Meister Consultants Group (MCG)

- CREST peer review network included several PUCs:
  - Colorado
  - Hawaii
  - Michigan
  - Washington

CREST Model

Key Assumptions: Cost-based, Fixed Payment, Long-Term

Balancing Priorities:
Ease of Use vs. Advanced Functionality
Automation vs. "No Macros"

Inputs	Constraints	Outputs
• Size & Performance • Capital Costs • O&M Costs • Financing • Ownership/Tax • Supplemental Revenue Streams • Incentives • Reserves • Depreciation	• Debt Service Coverage Ratios – Minimum – Average **Features** • Level of Cost Detail • Public/Private Ownership • Tax benefit carry-forward • Incentives	• Cost of Energy • Levelized Cost of Energy

Using CREST: Why and How? Well-Defined Objectives are Important

1. What are you trying to accomplish? (Policy maker perspective)
   a. Least-cost?
   b. Rapid deployment?
2. Cost-based analysis: identify all-in LCOE
   a. "Gap"/"Premium" analyses can be done as a derivative
3. Identify a range of outcomes
   a. Uncertainty of inputs
   b. Variety of project configurations
   c. "Prototype" or "Representative" project
4. Supplement other analyses, data and stakeholder feedback in rate-setting proceedings.
5. Inputs can be consensus-driven, based on historic data, or estimated based on experience.

MODEL INTRODUCTION & WALK-THROUGH…

Sustainable Energy Advantage, LLC

Office:

10 Speen Street, 3rd Floor
Framingham, MA 01701
(508) 665-5850
www.seadvantage.com

Contact:

Jason Gifford
tel. 802-846-7627
jgifford@seadvantage.com

Distributed Generation Contracts Program -Updates

STATE OF RHODE ISLAND
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Contract Results

- 27 DG projects awarded contracts since December 2011.
- 2 Wind Turbine projects
- 3 Small Solar projects
- 16 Medium Solar projects
- 6 Large Solar projects
- 1 Anaerobic Digestion project
- 21.413 MW have been awarded from the five (5) enrollments.

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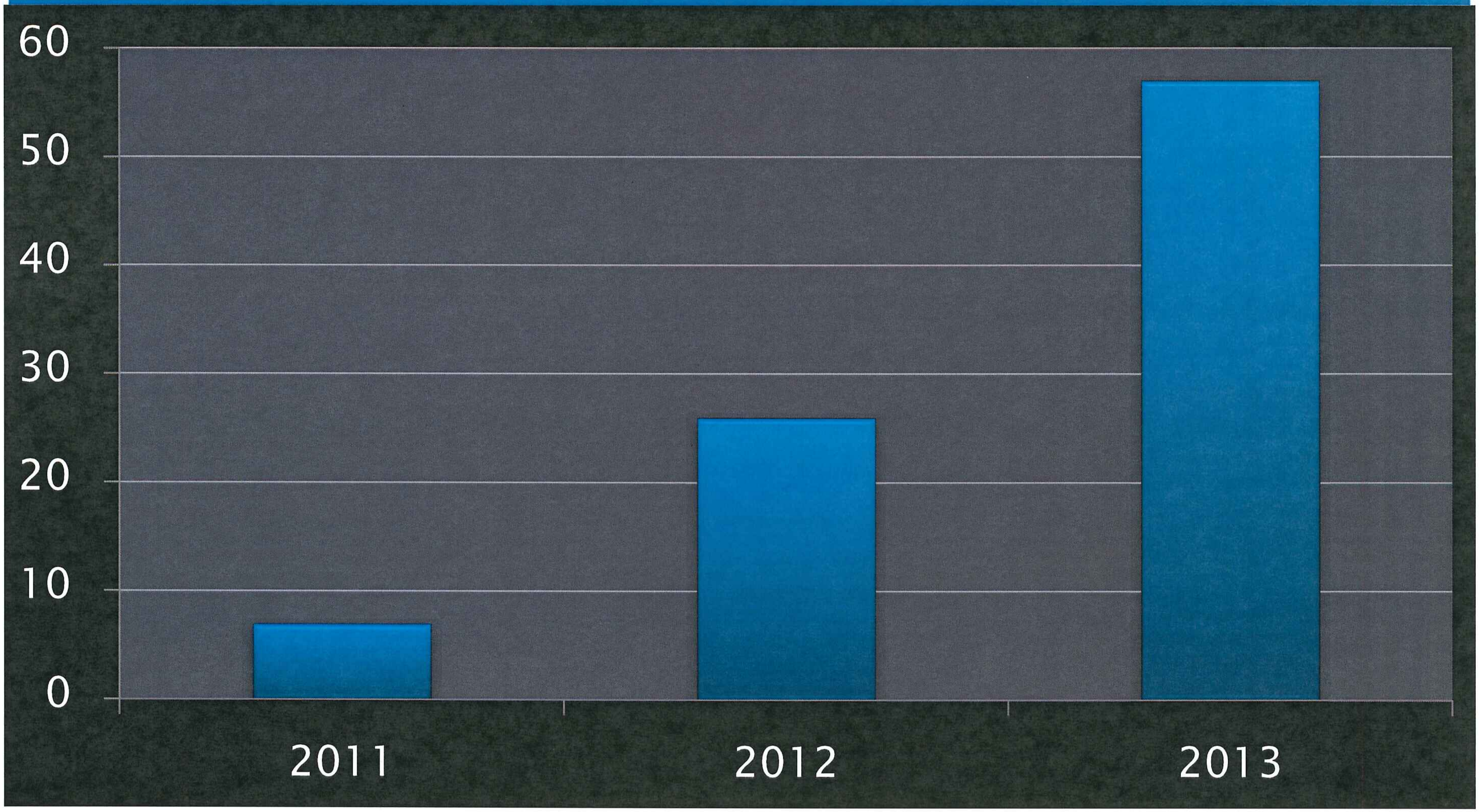
Application History



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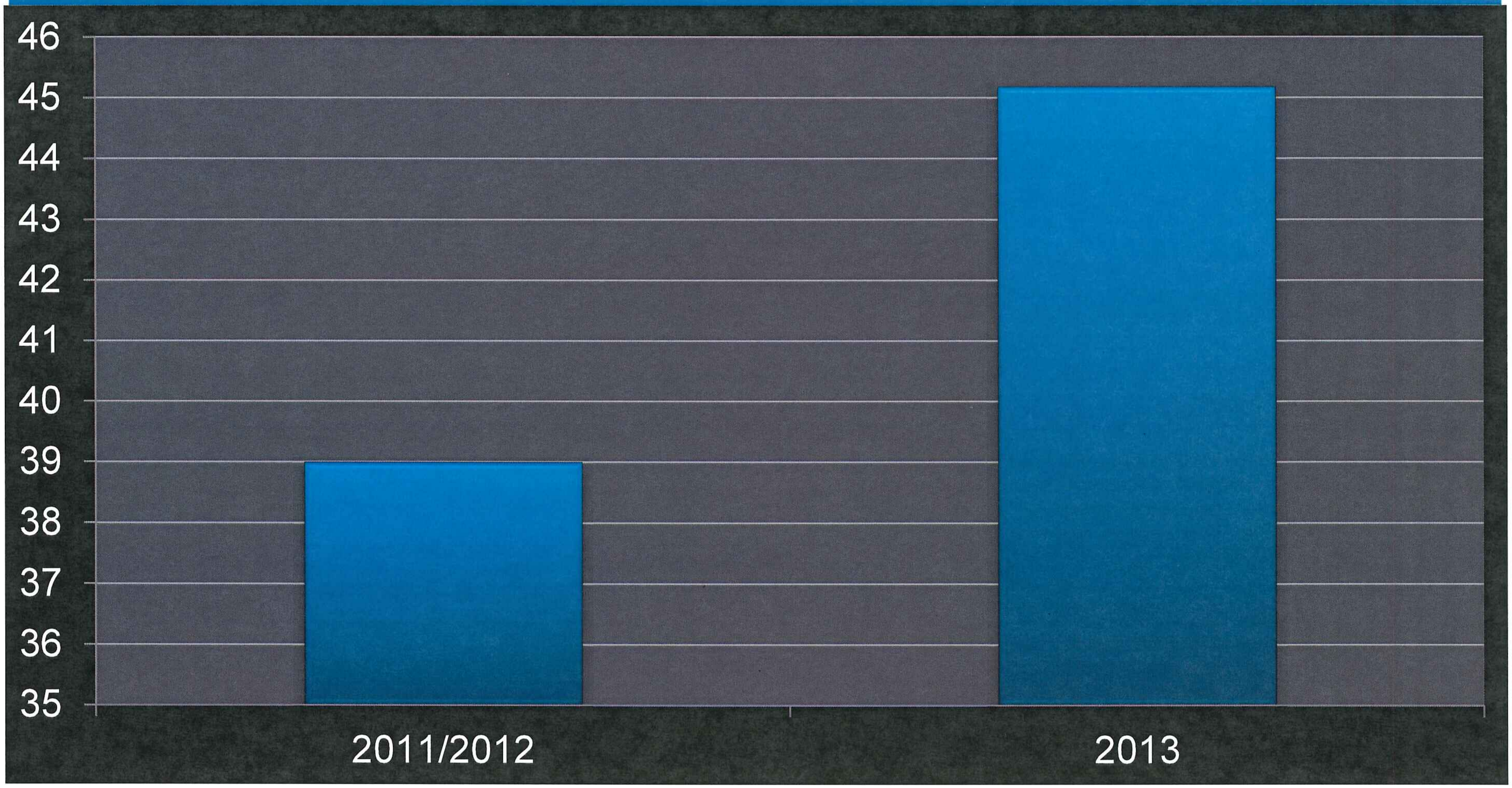
MW Application History



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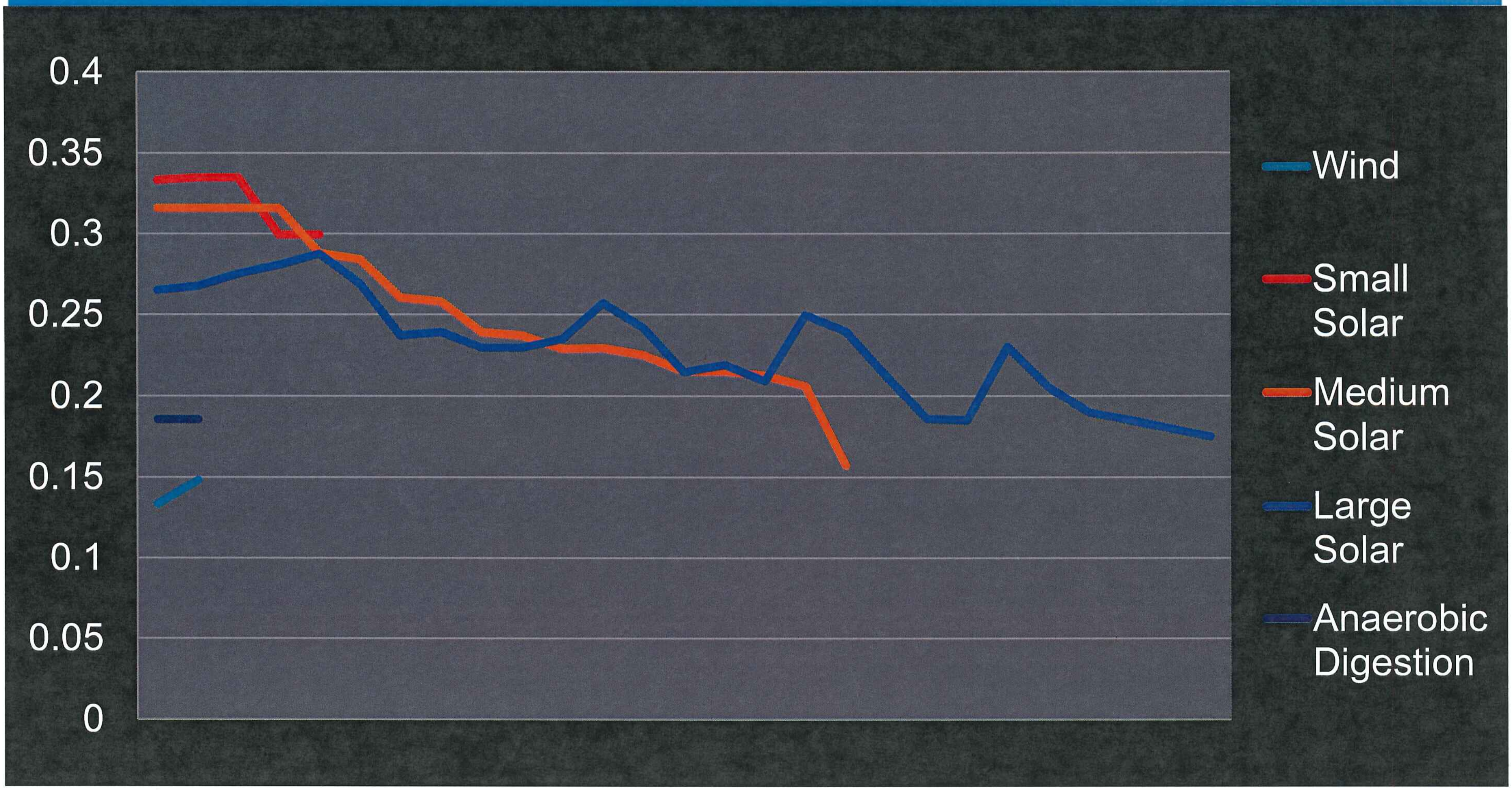
Application Ceiling Price History
December 2011 – September 2013



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These ceiling prices reflect the changes to the DG law from the 2013 legislation.

DG Projects Across the State

- DG projects have been proposed in the following municipalities:

- North Smithfield, Glocester, Bristol, Middletown, West Warwick, Bradford, Richmond, East Greenwich, North Kingstown, Hopkinton, Cumberland, Providence, Cranston, Lincoln, Richmond, Warwick, Pawtucket, Woonsocket, Warren, Coventry, Jamestown, Johnston, East Providence, Central Falls, West Greenwich, Westerly, Warren and Portsmouth

- The state has seen DG projects proposed in 28 of the 39 Cities and Towns.

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Project Locations

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STATE OF RHODE ISLAND
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ENERGY RESOURCES

Location	Technology/ System Size	Operational or Contract Deadline
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1 John C. Dean Memorial Blvd. Cumberland	Solar – 500 kW	January 2014
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35 Martin St. Cumberland	Solar – 500kW	January 2014
87 Woodville Alton Rd. Hopkinton	Solar – 500 kW	January 2014
100 Dupont Dr. Providence	Solar – 1.5 MW	January 2014

STATE OF RHODE ISLAND
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Location	Technology/ System Size	Operational or Contract Deadline
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45 Sharpe Dr. Cranston	Solar – 406 kW	September 2014
582 Great Rd. North Smithfield	Solar – 1.084 MW	September 2014
210 Piggy Lane Coventry	Wind – 1.5 MW	September 2014

Updates

- The final enrollment for 2013 will be from October 28th to November 8th.

- The OER and the Economic Development Corporation secured funding through the Renewable Energy Fund (REF) in September to perform an Economic and Jobs Impact Study on the DG and REF programs. The study will be completed and provided to the Governor and General Assembly by March 2014.

- ISO-New England launched a DG Forecast Working Group with the Northeast State Energy Offices, to identify and provide all of the DG installations and projects scheduled to become operational.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Questions/Comments

STATE OF RHODE ISLAND
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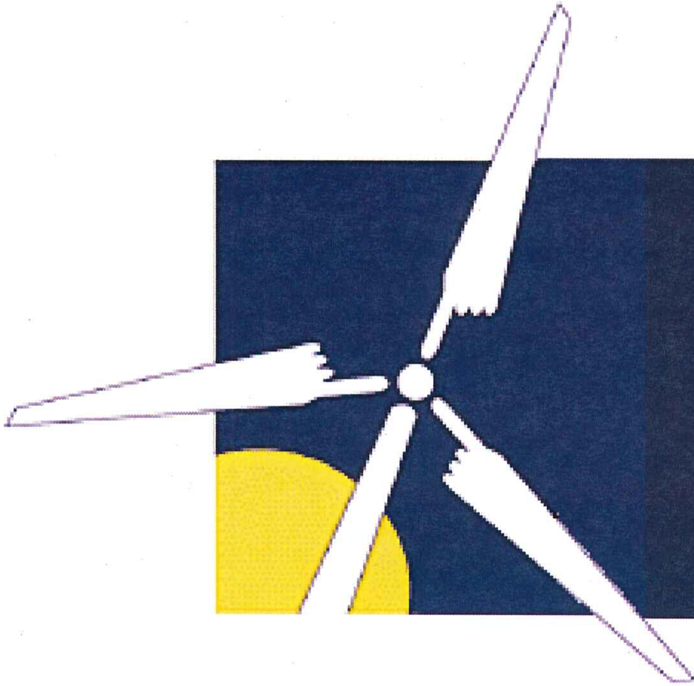
ENERGY RESOURCES



Rhode Island Distributed Generation Standard Contracts Program:

Preliminary Input Assumptions & Modeling Results for 2014 Ceiling Prices

October 22, 2013

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

Background: Changes from 2013 to 2014 (1)

- SB 641 Sub B - An Act Relating To Public Utilities and Carriers - Distributed Generation Standard Contracts
  - **Allow small-scale hydro projects** in DGSC program; **36-month window to reach commercial operation** (other technologies must come online within 18 months)
  - **Maximum project size reduced from 5 MW to 3 MW**
  - **Minimum** solar and wind project size = **50 kW**
  - Require **competitive bidding** for the small DG to decrease the cost of the DG program.
  - Small DG MW allocations separated from large DG MW allocations in each enrollment.
  - Flexibility allowing a DG project to avoid having its DG contract voided as long as it produces 90% of the output proposed in its application
  - Any unused kWh or MW to be eligible for use after 2014
  - Require quarterly status reports from projects awarded DG contract.
  - Require more feedback to the applicant from National Grid on the evaluation of the applicant's project proposal (if requested)
  - RI OER required to complete annual jobs, economic, and environmental impact study for each year of DGSC program, starting in 2014

Background: Changes from 2013 to 2014 (2)

- **2014 size & technology categories based on activity seen in 2013 and 2012 solicitations →** If few or no projects proposed, categories may have been modified.

- 2014 Ceiling Prices set for <u>7 classes</u>:
  - 3 Solar
  - 2 Wind
  - 1 Anaerobic Digestion
  - 1 Hydro
  - '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	501 kW – 3 MW	1.5 MW
Solar, Medium	201 – 500 kW	400 kW
Solar, Small	50 – 200 kW	150 kW
Wind, Large	1.0 MW – 3 MW	1.5 MW
Wind, Medium	50 kW – 999 kW	750 kW
Anaerobic Digestion	50 kW – 3 MW	500 kW
Hydroelectric	50 kW – 1.0 MW	500 kW

Response to Data Request (1)

- Limited
  - For other than solar, not sufficient to support CP adjustments

Comments – applicable to multiple technologies – provide helpful description of market conditions & impact on DG SC program:

- The non-recourse debt market is still very tight, which suggests that securing debt for capital intensive projects might be difficult
  - The assumption regarding D/E ratio should be consistent across the renewable technologies as financing would likely come from similar sources
- Treatment of federal tax policy
  - There are few Rhode Island-based investors that can fully monetize federal tax benefits, discouraging local participation
  - Stakeholders have also had difficulty realizing the full benefits of the Investment Tax Credit (ITC)

Response to Data Request (2)

- Ceiling prices
  - There is some stakeholder interest in doing away with ceiling prices completely and allowing for a fully competitive solicitation to set prices
  - Stakeholders feel that current ceiling price methodology does not take the full environmental benefit of these projects into account, and should increase prices accordingly
- Other issues
  - There is a disconnect between estimated and actual National Grid interconnection costs

- <u>Next Steps:</u>
  - Feedback during & after 1st stakeholder meeting
  - Interviews
  - Work with National Grid on summary of actual interconnection costs

SUMMARY RESULTS

Summary Results & Sensitivity Analysis

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 Proposed CP w/ITC/PTC + Bonus	2014 Proposed CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus***	2014 Proposed CP No ITC/PTC, No Bonus
Solar*, 501 +	24.95	Solar*, 501-3,000	21.75	23.00	~8%	N/A
Solar*, 251 – 500	28.40	Solar*, 201-500	24.15	25.35	~11%	N/A
Solar*, 101 – 250	28.80	Solar*, 50-200	25.25	26.55	~8%	N/A
Solar*, 50 – 100	29.95					
Wind*, 1,000-1,500	14.80	Wind*, 1,000-3,000	14.35	14.80	0%	18.70
Wind*, 400 – 999	16.20	Wind*, 50-999	15.95	16.20	0%	20.45
Wind*, 90 – 100	24.65					
AD**, 400 – 500	18.55	AD**, 50-3,000	17.50	18.55	0%	19.35
Hydro** 500-1,000	17.90	Hydro**, 50-1,000	16.95	17.90	0%	18.60

* ITC
** PTC
*** Note, changes in selected sub-class definitions prevents a direct comparison in these circumstances.

SOLAR

Est. of 15-year levelized contract: Solar

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 Proposed CP w/ITC/PTC + Bonus	2014 Proposed CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus***	2014 Proposed CP No ITC/PTC, No Bonus
Solar, 501 +	24.95	Solar, 501-3,000	21.75	23.00	~8%	N/A
Solar, 251 – 500	28.40	Solar, 201-500	24.15	25.35	~11%	N/A
Solar, 101 – 250	28.80	Solar, 50-200	25.25	26.55	~8%	N/A
Solar, 50 – 100	29.95					

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]

  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 (Smaller systems and likely redundant with Mass. SREC Database)
  - CEFIA project database (No systems >18kW in data set)
- Stakeholder Data Request
  - Limited (5) responses received.
- Follow up Interviews;
- Data available to SEA/MCG through other recent engagements

Costs embedded in total installed cost estimates include:

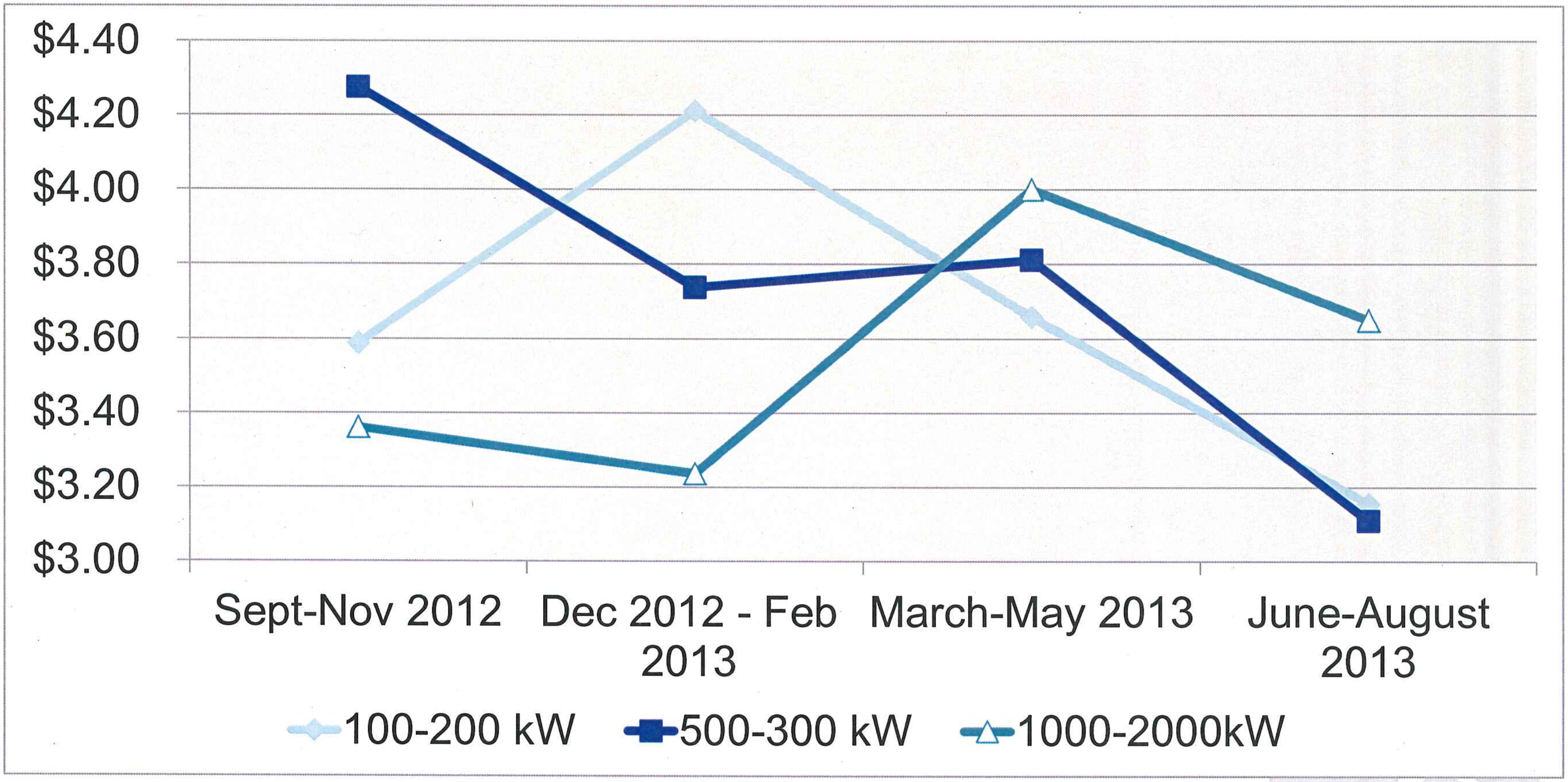
***Soft Costs**: development, permitting, engineering costs, as well as interest incurred during construction, the initial funding of all required reserve accounts, financing closing costs, and lender fees (if applicable)*

***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 2012-August 2013)

Mass SREC Database - Average Installed Cost by Bin Quarter ($/Watt)				
Size Bin (kW)	Sept-Nov 2012	Dec 2012 - Feb 2013	March-May 2013	June-August 2013
100-200kW	$3.59	$4.21	$3.66	$3.16
300-500kW	$4.28	$3.74	$3.81	$3.11
1,000-2,000kW	$3.36	$3.24	$4.00	$3.65

Mass SREC Database Trend: Average Cost
(Sept 2012-August 2013)

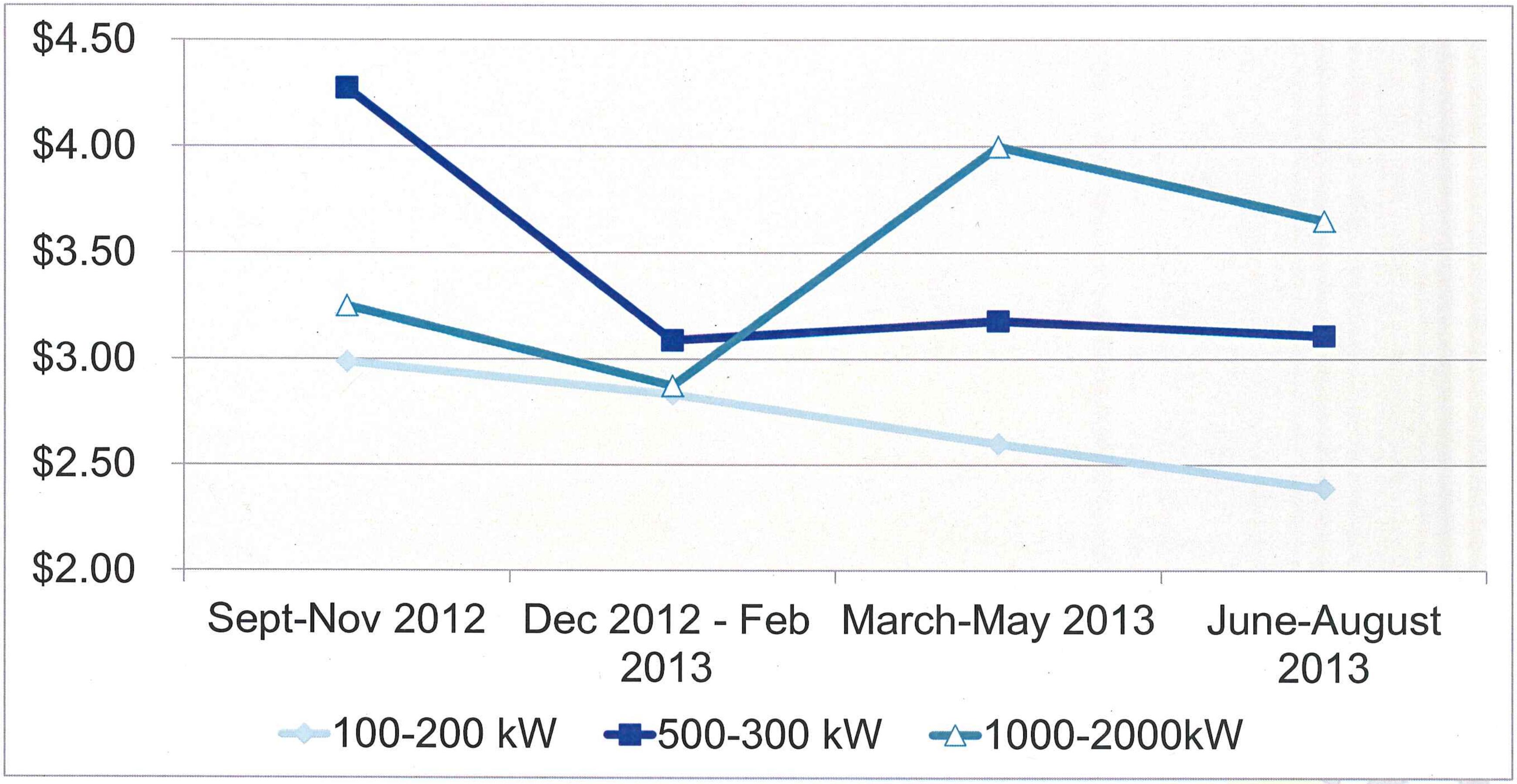


Mass SREC Database: Avg. - 1 Std. Deviation
(Sept 2012 – August 2013)

Mass SREC Database – Avg. Installed Cost minus 1 Std Dev by Qtr.

Size Bin (kW)	Sept-Nov 2012	Dec 2012 - Feb 2013	March-May 2013	June-August 2013
100-200kW	**$2.99**	**$2.83**	**$2.60**	**$2.39**
300-500kW	**$4.28**	**$3.09**	**$3.18**	**$3.11**
1,000-2,000kW	**$3.25**	**$2.87**	**$4.00**	**$3.65**

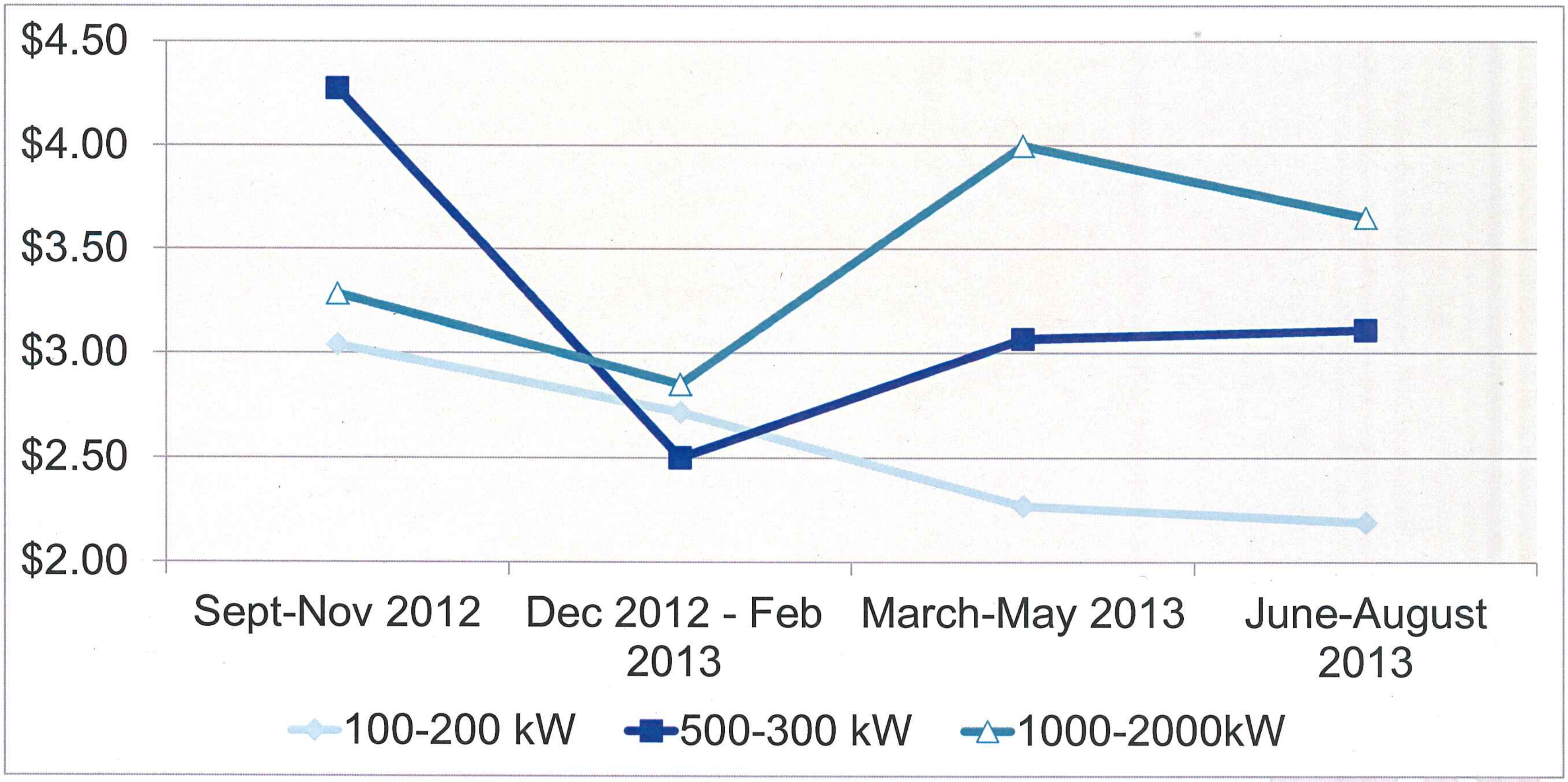
Mass SREC Database Minus 1 Standard Deviation
(Sept 2012-August 2013)



Mass SREC Database: Minimum Installed Cost in Each Bin

Mass SREC Database – Min. Installed Cost				
Size Bin (kW)	Sept-Nov 2012	Dec 2012 - Feb 2013	March-May 2013	June-August 2013
100-200kW	$3.04	$2.72	$2.27	$2.19
300-500kW	$4.28	$2.50	$3.07	$3.11
1,000-2,000kW	$3.28	$2.85	$4.00	$3.65

Mass SREC Database: Minimum Installed Cost in Each Bin



Operation & Maintenance (O&M) Cost

Sources

- 2012 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

Capacity Factor Comparison

Size Class	PV Watts CF	CF from 2011 - 2013	Proposed CF for 2014
50-200	14.25-14.85%	14.39%*	**14.39%**
201-500	14.25-14.85%	14.56%	**14.56%**
501+	14.25-14.85%	14.65%	**14.65%**

** Both comparing to 150kW size class from 2011*

No changes in PV Watts data since process to set 2013 Ceiling Prices.

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (1)

Input category*

Expected Annual Average Net capacity factor, (%) DC

Proposed Input = 14.39%

2013 Input = 14.39%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost

Proposed Input = $2,900

2013 Input = $3,150/kW

Interconnection cost ($)

Proposed Input = $50/kW [National Grid project data: $179/kW]

2013 Input = $50/kW

O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations

Proposed Input = $20/kW-yr

2013 Input = $20/kW-yr

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (2)

Input category*

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.3%

2013 Input = 0.3% of total proj. costs

Project Management, Yr 1 ($/yr)

Proposed Input = $1,400/yr

2013 Input= $1,400/yr

Land Lease, Yr 1 ($/yr)

Proposed Input = $2,500/yr

2013 Input = $2,500/yr

Annual average escalation rate for O&M expenses (%)

Proposed Input = 3%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0% (covered in lease)

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = yr 1 = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (3)

Input category*
Debt-to-equity ratio
Proposed Input = 50/50
2013 Input = debt optimized to cash flow
Debt tenor (years)
Proposed Input = 13 yrs
2013 Input = 13 yrs
Interest rate on debt (%)
Proposed Input = 6.0%
2013 Input = 6.5%
Lender's Fee (% of loan amt)
Proposed Input = included in cap. cost
2013 Input = included in cap. cost
Avg. Debt Service Coverage Ratio Target
Proposed Input = 1.40
2013 Input = 1.40
After Tax Return on Equity (e.g. IRR) (%)
Proposed Input = 10%
2013 Input =12%
Decommissioning Reserve?
Proposed Input = $0
2013 Input = $0 (= salvage value)

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (1)

Input category

Expected Annual Avg. Net c.f. (%)

Proposed Input = 14.56%

2013 Input = 14.56%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/$kW_{DC}$), excluding Interconnection Cost

Proposed Input = $2,550/kW

2013 Input = $2,650/kW

Interconnection cost ($)

Proposed Input = $200/kW [National Grid project data: $4/kW] [$1,080 for 260 kW solar installation]

2013 Input = $300/kW

O&M expenses (in $/$kW_{DC}$-year) in Year 1 of operations

Proposed Input = $20/kW-yr

2013 Input = $20/kW-yr

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (2)

Input category

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.3%

2013 Input = 0.3% of total proj. costs

Project Management, Yr 1 ($/yr)

Proposed Input = $6,500

2013 Input= $6,500/yr

Land Lease, Yr 1 ($/yr)

Proposed Input = $10,000

2013 Input = $15,000

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 3%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0%

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = yr 1 = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (3)

Input category
Debt-to-equity ratio
Proposed Input = 50/50
2013 Input = debt optimized to cash flow
Debt tenor (years)
Proposed Input = 13 yrs
2013 Input = 13 yrs
Interest rate on debt (%)
Proposed Input = 5.5%
2013 Input = 6.0%
Lender's Fee (% of loan amt)
Proposed Input = included in cap. cost
2013 Input = included in cap. cost
Avg. Debt Service Coverage Ratio Target
Proposed Input = 1.35
2013 Input = 1.35
After Tax Return on Equity (e.g. IRR) (%)
Proposed Input = 10%
2013 Input = 11%
Decommissioning Reserve?
Proposed Input = $0
2013 Input = $0 (= salvage value)

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

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%

2013 Input = 14.65%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/$kW_{DC}$), excluding Interconnection Cost

Proposed Input = $2,350/kW

2013 Input = $2,550/kW

Interconnection cost ($)

Proposed Input = $150/kW [National Grid project data: MA projects average $107/kW; RI projects average $153/kW]

2013 Input = $150/kW

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

Input category

O&M expenses (in $/kW$_{DC}$-year) in Yr 1 of operations

Proposed Input = $15/kW-yr

2013 Input = $15/kW-yr

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.25%

2013 Input = 0.25%

Project Management, Yr 1 ($/yr)

Proposed Input = $10,000

2013 Input= $10,000

Land Lease, Yr 1 ($/yr)

Proposed Input = $30,000

2013 Input = $34,500 to reflect tax on underlying land

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%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0%

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

Debt-to-equity ratio

Proposed Input = 50/50

2013 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 13 yrs

2013 Input = 13 yrs;

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

Input category

Interest rate on debt (%)

Proposed Input = 5%

2013 Input = 5.5%

Lender's Fee (% of loan amt)

Proposed Input = included in cap. cost

2013 Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.35

2013 Input = 1.35

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 10%

2013 Input =12%

Decommissioning Reserve?

Proposed Input = $200,000

2013 Input = $200,000

Details, Sources

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

- Stakeholder Data Requests
- 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 Data Requests

Interconnection

- National Grid (anticipated)
- Stakeholder Data Requests

Finance Structure, Cost of Debt/Equity

- Stakeholder Data Request
- SEA Experience

Performance

- No changes from 2013 CP process

Incentives

- Federal Investment Tax Credit (ITC) assumed available to all solar projects operational on or before 12/31/2016.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 80% monetization of federal ITC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- COD achieved in 2014
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio Target: 1.35X
- 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%

- *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 2013 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	12.13
17	2030	12.53
18	2031	12.94
19	2032	13.36
20	2033	13.79
21	2034	14.24
22	2035	14.7
23	2036	15.18
24	2037	15.67
25	2038	16.17

WIND

Est. of 15-year levelized contract: Wind

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 Proposed CP w/ITC/PTC + Bonus	2014 Proposed CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus***	2014 Proposed CP No ITC/PTC, No Bonus
Wind, 1,000-1,500	14.80	Wind, 1,000-3,000	14.35	14.80	0%	18.70
Wind, 101 – 999	16.20	Wind, 50-999	15.95	16.20	0%	20.45
Wind, 90 – 100	24.65					

Comments

- Project Categories
  - Feedback requested **reinstatement of the small wind category** (based on visibility and success of 100kW turbines)
- Ceiling Prices
  - As industry has matured, market forces are playing a larger role; **higher ceilings will allow for more competition without discouraging bids**
  - It was suggested that **late changes** to the 2013 ceiling price based on PTC availability hurt participation and undermined the integrity of the stakeholder process
- Other issues
  - Stakeholders commented that the **issue of property taxes has not been adequately addressed** in Rhode Island. They opined that the state should develop a clear policy on how renewable energy projects should be taxed, and in the meantime, ceiling prices should reflect a worse case scenario.

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Qualifying wind projects assumed to elect the ITC in lieu of the PTC
  - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without ITC
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 90% monetization of federal ITC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- Commercial operation achieved in 2014
- Project Useful Life: 20 years
- Average Debt Service Coverage Ratio Target: 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%
- Market value of production (assumed revenue) post-contract = 90% of sum of ***wind-weighted*** energy and capacity price forecasts from 2013 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	11.01
17	2030	11.39
18	2031	11.78
19	2032	12.19
20	2033	12.61

ANAEROBIC DIGESTION

Est. of 15-year levelized contract: Anaerobic Digestion

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 Proposed CP w/ITC/PTC + Bonus	2014 Proposed CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus***	2014 Proposed CP No ITC/PTC, No Bonus
AD, 400 – 500	18.55	AD, 50-3,000	17.50	18.55	0%	19.35

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Anaerobic digesters eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 90% monetization of federal PTC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- Commercial operation achieved in 2014
- Project Useful Life: 20 years
- Average Debt Service Coverage Ratio Target: 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%
- Market value of production (assumed revenue) post-contract = 90% of sum of energy and capacity price forecasts from 2013 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	11.35
17	2030	11.72
18	2031	12.10
19	2032	12.49
20	2033	12.90

HYDRO

Est. of 15-year levelized contract: Hydro

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 Proposed CP w/ITC/PTC + Bonus	2014 Proposed CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus***	2014 Proposed CP No ITC/PTC, No Bonus
Hydro 500-1,000	17.90	Hydro, 50-1,000	16.95	17.90	0%	18.60

Hydro Comments

- **Consider technology longevity** and front-loaded development costs when establishing DG contract term (**15 yrs is too short**).
  - The true value of hydro resources is out 20-30 years after the sunk costs are recovered and the project still has lots of life left.
- **Hydro is extremely site specific**.
  - The turbines are specifically designed and manufactured for each application/site;
  - As a result, the costs can vary widely;
  - Beyond the basic turbine and generator package, the potential civil works required to install the units typically varies considerably (again depending on the site).
- Higher permitting costs (which are all equity funded), paid over a longer period of time (time value of money) need to be considered.

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Hydro is eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 90% monetization of federal PTC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- Commercial operation achieved in 2016
- Project Useful Life: 30 years
- 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%
- Market value of production (assumed revenue) post-contract = 75% of sum of energy and capacity price forecasts from 2013 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	11.49
17	2030	11.83
18	2031	12.18
19	2032	12.54
20	2033	12.90
21	2034	13.28
22	2035	13.67
23	2036	14.07
24	2037	14.49
25	2038	14.91
26	2039	15.35
27	2040	15.80
28	2041	16.26
29	2042	16.74
30	2043	17.23

Sustainable Energy Advantage, LLC

10 Speen Street
Framingham, MA 01701
508.665.5850
www.seadvantage.com

Jason Gifford
tel. 508.665.5856
jgifford@seadvantage.com

Distributed Generation

RI Economic Development Corporation

The Interconnection Process

Thursday, November 07, 2013

nationalgrid

Agenda

- Interconnection – The Process
- Net Metering

Interconnection Tariffs

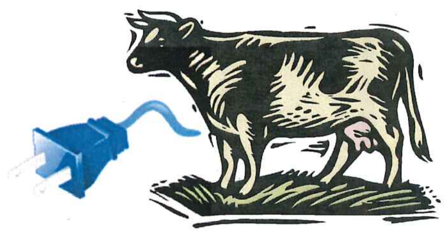
- The RI PUC adopted a revised tariff titled, “ RIPUC #2078, Standards for Connecting Distributed Generation”, on November 30, 2011.
-
  - Includes interconnection standards and renewable energy interconnection process.
  - Current version of “Standards for Interconnecting Distributed Generation” is can be found at: https://www.nationalgridus.com/narragansett/home/energyeff/4_interconnect.asp

- The RI PUC adopted a revised tariff titled “RIPUC #2075, Net Metering Provision

  - Includes Eliglble Net Metering Rate Classes and Technologies
  - Current version of “Net Metering Provision “ can be found at: https://www.nationalgridus.com/narragansett/home/energyeff/4_net-mtr.asp







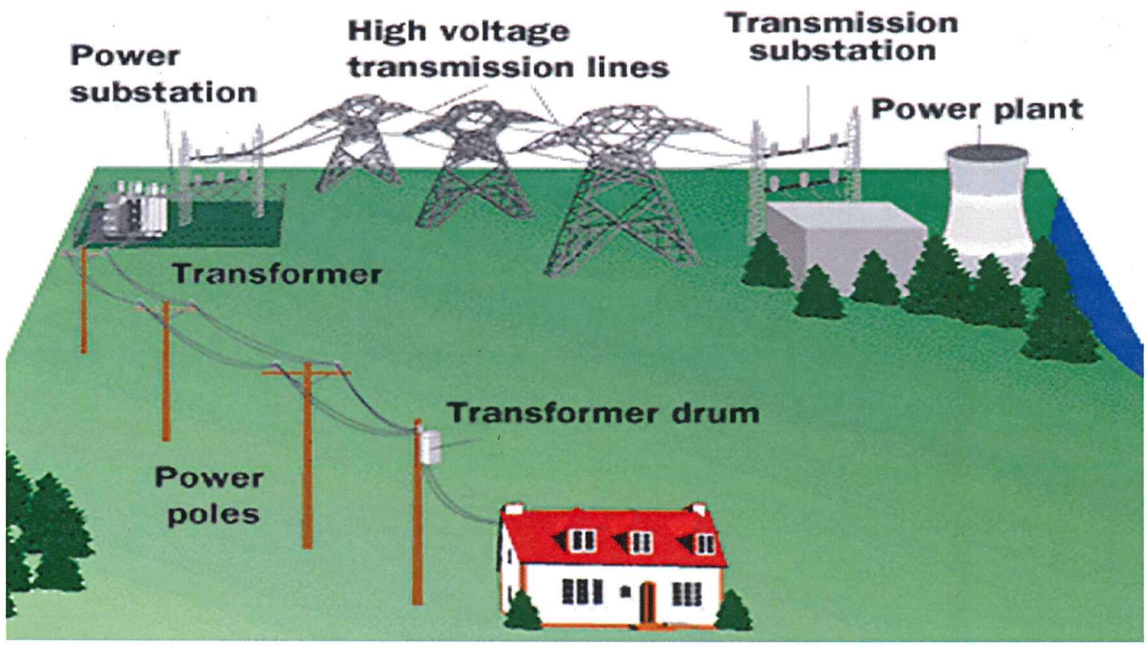

How Does the Electric Grid Work?

• **Generators (Power Plants):** Produce electricity (usually large and centralized – nuclear, coal, natural gas)

•**Transmission System:** Transmits electricity at high voltage from generators to distribution systems (where the power is needed)

•**Distribution System:** Distributes electricity to customers via lower voltage wires

•**Substations and Transformers:** Used to “step-down” voltage to the appropriate task



Interconnection 101: The Basics

1. The customer starts the review process by requesting, filling out and submitting an application package to the local utility

2. The utility begins review to determine appropriate application path

3. If approved, the applicant will be required to sign an interconnection agreement with the utility. The system must be installed within 12 months of the agreement, or else a new application is required.

4. If there is a dispute over an application, the interconnection standards released by the RI Public Utilities Commission (PUC) include a dispute resolution process.

5. At first glance, the interconnection process seems simple, but there is a significant amount of information needed by the utility to successfully process the application. Delays are common due to missing information, so it is important that the system design engineer help with the application process.

6. Contact National Grid, RI PUC or RI OER assistance or with queries even **before** the system design process. Everything Starts with the Application!

Everything starts with the **Application**

- A complete complex application package includes:
  - All appropriate sections of 4-page application completely filled out. Customer will likely need assistance from vendor/engineer.
  - **Application fee** $3/KW ($300 minimum and $2,500 maximum). This fee covers the initial review. Note: if Renewable DG, Feasibility Study fee applies in lieu of Application fee.
  - **Stamped electric one-line diagram**, preferably showing relay controls (one copy) (Stamped by Rhode Island Electrical PE)
  - **Site diagram** (one copy)
  - One copy of any **supplemental information** (if electronic – single copy acceptable)
  - Identify electric customer and owner of proposed generation
  - **Schedule B** if planning to Net Meter

- Errors or problems with application will slow down the process and *"stop the clock"*

- Send **Electronic copy** of all documents **preferred** if possible – Easier to distribute, saves paper, and is faster. However, submit first page of application with application fee.

Interconnection Review Paths

• There are three different interconnection review paths a project can follow based on generation type, size, customer load and the characteristics of the grid where the system is to be located.

Simplified	Expedited	Standard
For PV and other inverter based technologies served by radial systems, 10k W or less 1-Phase or up to 25k W 3-Phase [Note: Simplified Spot Network path is 30-90 days]	For inverter-based systems greater than 10 kW 1-Phase or greater than 25 kW 3-Phase and other systems of all sizes that are served by radial systems and meet other requirements.	All projects not eligible for simplified or expedited review, including all systems on networks
Typical Projects: small PV, demonstrations or homeowner wind	**Typical Projects:** certified large renewables, cogeneration, and other turbine or engines of any size	**Typical Projects:** uncertified large projects, unusually complex projects or projects of any size located on networks
Total Maximum Days: 15*	Total Maximum Days: 40 – 60*	Total Maximum Days: 125-150*

*** Without delays**

Responsibility of Costs

- **Interconnecting customer responsible for:**
  - Application Fee
    - Simplified Process: Fee Waived (except for Simplified spot network)
    - Expedited and Standard: $3/kW ($300 min and $2,500 max)
  - Renewable DG: Feasibility Study Fee is required in lieu of Application Fee
  - Costs of impact and detailed studies if required
  - Grid modification requirements – can include ongoing charges
  - Witness Test Fee
  - Costs associated with design, construction and installation of the facility and all associated interconnection equipment on the customer's side of the meter
  - Most smaller projects will not require impact or detailed studies or distribution system upgrades
  - See Fee Schedule for details

Interconnection Process Timeframes

Table 1 – Time Frames (Note 1)

Review Process	Simplified	Expedited	Standard		Simplified Spot Network
Eligible Facilities	Listed Small Inverter	Listed DG	Any DG	Renewable DG	Listed Inverter ≤ 15 kW single-phase
Acknowledge receipt of Application	(3 days)	(3 days)	(3 days)	(3 days)	(3 days)
Review Application for completeness	10 days	10 days	10 days	10 days	10 days
Complete Review of all screens	10 days	25 days	n/a	n/a	Site review 20/90 days (Note 2)
Complete Supplemental Review (if needed)	n/a	20 days	n/a	n/a	n/a
Complete Standard Process Initial Review	n/a	n/a	20 days	20 days if Feasibility Study not requested	n/a
Send Follow-on Studies Cost Agreement	n/a	n/a	5 days	5 days	n/a
Feasibility Study (if requested)		n/a	n/a	20 calendar days	
Complete Impact Study or ISRDG (if requested)	n/a	n/a	55 days	The shorter of 55 days or 90 calendar days	n/a
Complete Detailed Study (if requested)	n/a	n/a	30 days	30 days	n/a
Send Executable Agreement (Note 3)	Done	10 days	15 days	15 days	Done (comparable to Simplified for radial)
Total Maximum Days (Note 4)	15 days	40/60 days (Note 5)	125/150 days (Note 6)	Varies depending on which studies are done (Note 6)	40/100 days
Notice/Witness Test	≤ 1 day with 10 day notice or by mutual agreement	1-2 days with 10 day notice or by mutual agreement	By mutual agreement	By mutual agreement	1 day with 10-day notice or by mutual agreement

Interconnection Process Fee Schedule

	Simplified	Expedited	Standard		Simplified Spot Network
	Listed Small Inverter	Listed DG	Any DG including Renewable DG not requesting a Feasibility Study or ISRDG	Renewable DG requesting a Feasibility Study or ISRDG	Listed Inverter ≤ 15 kW
Application Fee (covers Screens)	0 (Note 1)	\$3/kW, minimum \$300, maximum \$2,500	\$3/kW, minimum \$300, maximum \$2,500	N/A	≤3 kW \$100, >3 kW \$300
Supplemental Review or Additional Review (if applicable)	N/A	Up to 10 engineering hours at \$125/hr (\$1,250 maximum) (Note2)	N/A	N/A	N/A
Standard Interconnection Initial Review	N/A	N/A	Included in application fee (if applicable)	N/A	N/A
Feasibility Study	N/A	N/A	N/A	Residential : ≤25kW: \$0 >25kW: \$50 Non-residential: ≤100kW: \$100 ≤250kW: \$300 250kW–1MW: \$1,000 >1MW: \$2,500	N/A
Impact Study or ISRDG	N/A	N/A	Actual cost (Note 3)	Residential : ≤25kW: \$0 >25kW: \$100 Non-residential: ≤100kW: \$500 ≤250kW: \$1,000 250kW–1MW: \$5,000 >1MW: \$10,000 (Note 4)	N/A
Detailed Study (if required)	N/A	N/A	Actual cost (Note 3)	Actual cost (Note 3)	N/A
Facility Upgrades	N/A (Note 5)	Actual cost	Actual cost	Actual cost	N/A
O&M (Note 6)	N/A	TBD	TBD	TBD	N/A
Witness Test	0	Actual cost, up to \$300 + travel time (Note 7)	Actual Cost	Actual Cost	0 (Note 8)

Many Stakeholders Involved

Utility

- Application analyst – processes application and contracts
- Lead Engineer for reviews/studies
- Relay Engineering
- Distribution Planning
- Distribution Dispatch
- Distribution Design Engineering
- Meter Operations
- Meter Engineering
- Meter Data Services
- Relay Telecom Operations
- Inspection team
- Customer Service / Billing
- Legal…

Interconnecting Customer

- Customer
- Equipment vendor
- Lead contractor
- Electrician
- Electrical Engineer (PE)
- Relay Engineer
- Relay testing firm
- Legal

ISO-NE
(If necessary)

Upgrades and Modifications

- If **aggregate generation** on a feeder is over 7.5% of peak feeder load, there may be special reviews required.
- **Feeder voltage** may impact the size of generator that can be safely and reliably interconnected at the distribution level. (e.g. 4.1KV, 23KV, 69KV)
  - Intermittent sources (solar, wind) can cause unacceptable voltage changes from cloud cover for solar or high wind cut-off from wind.
- If the generator will **sell on market** and has to apply through ISO-NE, the process may take longer than the standard time frames.
- Generators over 10 KW are most likely going to require three-phase. Make sure the customer has three-phase service available. If a line extension is required, it is at the customer's expense.

Interconnection Summary and Recommendations

- *Submit your interconnection application with National Grid early*, during conception phase before committing to buy no matter how simple or small the DG might be.

- You can always request general utility information about a specific location from your utility

- Large interconnection applications take longer to study

- Stand alone (no load behind the meter) interconnection application take longer to study

- Interconnection timeframes do not apply to distribution system modifications or construction if required.

Summary and Recommendations
(continued)

- The Interconnection Standard is a wealth of information – get to know it
- Time frames are standard working days and do not include delays due to missing information
- Interconnection expenses such as application fees, required studies, potential system modifications and witness tests should be budgeted into each project
- Hire an engineer to help with application process
- ISO-NE notification not included in time frame
- Interconnection applications have increased significantly in the past few years – APPLY EARLY!!!

Net Metering in Rhode Island

- December 2011 Net Metering Provision Tariff
  - **"Eligible Net Metering Resource"** shall mean eligible renewable energy resource as defined in R.I.G.L. Chapter 39-26-5 including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels.
  - **"Eligible Net Metering System"** shall mean a facility generating electricity using an Eligible Net Metering Resource that is reasonably designed and sized to annually produce electricity in an amount that is equal to or less than the Renewable Self-generator's usage at the Eligible Net Metering System Site measured by the three (3) year average annual consumption of energy over the previous three (3) years at the electric distribution account(s) located at the Eligible Net Metering System Site.

Net Metering in Rhode Island

- **"Eligible Net Metering System Site"** shall mean the site where the Eligible Net Metering System is located or is part of the same campus or complex of sites contiguous to one another and the site where the Eligible Net Metering System is located or a farm in which the Eligible Net Metering System is located.
  - Except for an Eligible Net Metering System owned by or operated on behalf of a municipality or multi-municipal collaborative through a municipal net metering financing arrangement, the purpose of this definition is to reasonably assure that energy generated by the Eligible Net Metering System is consumed by net metered electric delivery service account(s) that are actually located in the same geographical location as the Eligible Net Metering System.
  - Except for an Eligible Net Metering System owned by or operated on behalf of a municipality or Multi-municipal Collaborative through a Municipal Net Metering Financing Arrangement, all of the Net Metered Accounts at the Eligible Net Metering System Site must be the accounts of the same customer of record and customers are not permitted to enter into agreements or arrangements to change the name on accounts for the purpose of artificially expanding the Eligible Net Metering System Site to contiguous sites in an attempt to avoid this restriction. However, a property owner may change the nature of the metered service at the delivery service accounts at the site to be master metered (as allowed by applicable state law) in the owner's name, or become the customer of record for each of the delivery service accounts, provided that the owner becoming the customer of record actually owns the property at which the delivery service account is located.
  - As long as the Net Metered Accounts meet the requirements set forth in this definition, there is no limit on the number of delivery service accounts that may be net metered within the Eligible Net Metering System Site.

Net Metering Credits

- Energy use is "netted" over the billing month
  - If there is net energy use – utility will bill customer for net use
  - If net energy export – export kWH * the following
    - Renewable installations will be credited at near retail rate for excess kWH (minus conservation and renewable energy charges).
- Tariff allows credits to be allocated (with limitations)
- Customer still responsible for customer charges and demand charges

			Credit the following charges			
min	**max**	**Type**	**Default Service**	**Distribution**	**Transmission**	**Transition**
0	5,000 KW	Renewable	X	X	X	X

Net Metering Credits

- If there is excess at the end of the year
  - **"Excess Renewable Net Metering Credit"** shall mean a credit that applies to an Eligible Net Metering System for that portion of the Renewable Self-generator's production of electricity beyond one hundred percent (100%) and no greater than one hundred twenty-five (125%) of the Renewable Self-generator's own consumption at the eligible net metering system site during the applicable billing period. Such Excess Renewable Net Metering Credit shall be equal to the Company's avoided cost rate, defined for this purpose as the Standard Offer Service kilowatt-hour (kWh) charge for the rate class and time-of-use billing period, if applicable, applicable to the delivery service account(s) at the Eligible Net Metering System Site.
- Customer must fill out Schedule B in the net-metering tariff to apply
  - https://www.nationalgridus.com/narragansett/home/energyeff/4_net-mtr.asp

Net Metering Summary

- If planning to Net Meter, submit Schedule B with interconnection application
- Correctly fill out Schedule B
  - Name must match electric account of Host Customer
  - Must be signed by Host Customer
- Submit 3 year average usage history.
- If allocating, verify name/address/account info of customer(s) – or will need to submit corrected form

Interconnection Contacts & Tariff Links

National Grid – RI

- Email: distributed.generation@us.ngrid.com
- Phone: John Kennedy | 401-784-7221
- Tariff Link: https://www.nationalgridus.com/narragansett/home/energyeff/4_interconnect.asp

UsefulLinks (available on our website)

Electric System Bulletin (ESB) 756 For contractors and customers looking for technical information on parallel generation with the National Grid electric power system

Rhode Island Office of Energy Resources Promoting energy efficiency and renewable energy in Rhode Island

Rhode Island Economic Development Corporation Managing the Rhode Island Renewable Energy Fund

Energy Efficiency Services National Grid can help you manage your energy usage through our energy efficiency services and incentives.

Procurements Procurements for the National Grid Distribution Companies to meet their energy supply service requirements

Solar Energy Business Association of New England Lists many of the local contractor resources for solar energy

Northeast Sustainable Energy Association A leading Northeast organization of professionals who promote sustainable energy and clean technology

Department of Energy U.S. DOE Federal site for Energy Efficiency and Renewable Energy

Check out National Grid's 5 MW **Solar Project**. This link provides real time solar generation information.

2014 Distributed Generation Contracts Program - Megawatt Allocation Plan
<u>Tentative Scenarios</u>

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Thursday, November 7, 2013

Tentative Megawatts Available

- Assumed Scenario – 13 megawatts (MW) available for the 2014 DG Program. This will be subject to change by late November.

- Additional MW may be made available in 2014. This will be dependent on the projects awarded contracts in July 2012 and March 2013.

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

Megawatt Availability History

2011 – 5 MW

2012 – 15 MW*

2013 – 13.8 MW

2014 – 13 MW*

*The 2012 program had MW roll over into 2013 by the OER.

*The 2014 program will be subject to change, depending on the outcome of the final enrollment in 2013.

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

2014 Allocation Plan Scenarios

- There could be 6 scenarios that happen with the enrollments in 2014.
- The scenarios would allow National Grid to shift MW or kilowatts (kW) that are not used by a specific technology to other technologies where there is demand.
- The OER anticipates each of the eligible technologies being awarded a contract in 2014.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Allocation Plan – First Scenario

Technology	2013 PUC Approved Allocation	2014 Proposed Allocation
Small-Medium Solar	1.3 MW	830 kW
Wind	1.5 MW	1.5 MW
Small-Scale Hydropower	-	500 kW
Anaerobic Digestion	500 kW	500 kW
Large Solar	1.3 MW	1 MW
Total	4.6 MW	4.33 MW

Allocation per enrollment. Three enrollments per year.

State of Rhode Island
Office of Energy Resources

Allocation Plan – Second Scenario

Technology	Allocation
Small-Medium Solar	1.08 MW
Wind	1.5 MW
Anaerobic Digestion	500 kW
Large Solar	1.25 MW
Total	4.33 MW

If there are no small-scale hydropower applications submitted.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Allocation Plan – Third Scenario

Technology	Allocation
Small-Medium Solar	1.08 MW
Wind	1.5 MW
Small-Scale Hydropower	500 kW
Large Solar	1.25 MW
Total	4.33 MW

If there are no anaerobic digestion applications submitted.

Allocation Plan – Fourth Scenario

Technology	Allocation
Small-Medium Solar	1.58 MW
Anaerobic Digestion	500 kW
Small-Scale Hydropower	500 kW
Large Solar	1.75 MW
Total	4.33 MW

If there are no wind turbine applications submitted.

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

Allocation Plan – Fifth Scenario

Technology	Allocation
Small-Medium Solar	1.33 MW
Wind	1.5 kW
Large Solar	1.5 MW
Total	4.33 MW

If there are no anaerobic digestion and small-scale hydropower applications submitted.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Allocation Plan – Sixth Scenario

Technology	Allocation
Small-Medium Solar	1.83 MW
Large Solar	2.5 MW
Total	4.33 MW

If there are no wind, anaerobic digestion or small-scale hydropower applications submitted.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Possible Additional MW in 2014

- An additional 7.311 MW could become available in 2014.
- July 2012 DG Contracts (5.127 MW) – Operational Deadline: February/March 2014
- March 2013 DG Contracts (2.184 MW) – Operational Deadline: October/November 2014
- In the event that any of the awarded projects fail to be operational by their contractual deadline, then National Grid shall put those MW into the 2014 DG program.

Possible Additional MW in 2014

- National Grid shall notify the OER and the DG Board of any kW/MW that become available for the 2014 program, and allocate those kW/MW to the technologies with there is the greatest demand.

- Notice of any changes in the allocations and scheduled enrollments shall be posted on the OER and National Grid websites.

Tentative Enrollment Timeline

March/April

July/August

October/November

Pending the RI Public Utility Commissions review and approval of the 2014 plan. These timelines will be subject to change.

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

Questions/Comments

Written comments are due to the OER by Thursday, November 14th

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

Rhode Island Distributed Generation Standard Contracts Program:

Public Meeting #2

2nd Draft Proposed 2014 Ceiling Prices

November 14, 2013

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

Introduction & Agenda

Process:

1. Data requests, research and analysis
2. Distribute initial findings and supporting data to stakeholders
3. Public Meeting #1 – discuss and take comments on initial findings
4. *Distribute MS Excel CREST Models*
5. Distribute revised findings in preparation for Public Meeting #2
6. Public meeting #2:
   - Review stakeholder feedback from/since 1st public meeting
   - Discuss 2nd Draft Proposed 2014 Ceiling Prices
   - Take additional stakeholder comments to inform PUC filing
7. Next Steps

Feedback & Modeling Adjustments

Stakeholder Feedback:	Modeling Change?	
	Yes	No
Interconnection cost estimates increasing	✓	
Difficulty monetizing federal tax benefits	✓	
Actual wind production << estimates	✓	
Wide range of uncertainty in property taxes		✓
Other benefits attributable to DG		✓
Updates independent of feedback:		
Update to forecast of post-contract market value of production (energy, capacity and $5 RECs)	✓	

SUMMARY RESULTS

Summary Results: Comparison to 2013 & Meeting 1

Tech., class (kW)	2013 CP w/ITC/PTC, No Bonus	Tech., class (kW)	2014 1st Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	Net Change from 2013 w/ITC/PTC, No Bonus	Adjustments****
Solar*, 501 +	24.95	Solar*, 501-3,000	23.00	23.50	-6%	Adj. to Interconnect Cost Assumption (+$50/kW)
Solar*, 251 – 500	28.40	Solar*, 201-500	25.35 (26.75)+	27.30	-4%***	
Solar*, 101 – 250	28.80	Solar*, 50-200	26.55	27.10	-6%***	
Solar*, 50 – 100	29.95					
Wind*, 1,000-1,500	14.80	Wind*, 1,000-3,000	14.80	16.70	+13%	IC: +$50/kW CF: -1.5% point
Wind*, 400 – 999	16.20	Wind*, 50-999	16.20	16.20	0%	None
Wind*, 90 – 100	24.65					
AD**, 400 – 500	18.55	AD**, 50-3,000	18.55	18.55	0%	None
Hydro** 500-1,000	17.90	Hydro**, 50-1,000	17.90	17.90	0%	None

* ITC ** PTC

*** Note, changes in selected sub-class definitions prevents a direct comparison in these circumstances.

**** **All solar + large wind: ITC/PTC monetization adjusted from 90% to 80%; post-contract market value of production updated per 2013 AESC.**

+ Due to computational error, the CP for Solar 251-499 was incorrectly reported at the first public meeting. The correct value is 26.75 ¢/kWh, and was used as the starting point to calculate the 2nd draft ceiling price for that category.

Summary Results: Sensitivity to Federal Incentives

Tech., class (kW)	2014 2nd Draft CP w/ITC/PTC + Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP No ITC/PTC, No Bonus
Solar*, 501-3,000	22.25	23.50	N/A
Solar*, 201-5000	25.90	27.30	N/A
Solar*, 50-200	25.75	27.10	N/A
Wind*, 1,000-3,000	15.60	16.70	19.65
Wind*, 50-999	15.55	16.20	19.95
AD**, 50-3,000	17.70	18.55	19.55
Hydro**, 50-1,000	17.25	17.90	18.85

* ITC ** PTC

SOLAR

Est. of 15-year levelized contract: Solar

Tech., class (kW)	2014 2nd Draft CP w/ITC/PTC + Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP No ITC/PTC, No Bonus
Solar*, 501-3,000	22.25	23.50	N/A
Solar*, 201-500	25.90	27.30	N/A
Solar*, 50-200	25.75	27.10	N/A

Notes:

- ❑ Competitive market pressure has driven solar PPA bid prices down dramatically.
- ❑Individual cost, financing and performance assumptions that accurately represent the implications of this behavior are difficult to model.
- ❑Aggressive bidding strategies may impact the level of project attrition after selection and before commercial operation.

Incentives

- Federal Investment Tax Credit (ITC) assumed available to all solar projects operational on or before 12/31/2016.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 80% monetization of federal ITC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

WIND

Est. of 15-year levelized contract: Wind

Tech., class (kW)	2014 2nd Draft CP w/ITC/PTC + Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP No ITC/PTC, No Bonus
Wind*, 1,000-3,000	15.60	16.70	19.65
Wind*, 50-999	15.55	16.20	19.95

Notes:

❑ There has been a substantial reduction in *community wind* development activity over the past several years. This impairs the ability to obtain meaningful data against which to benchmark Rhode Island wind projects.

❑The cost gap between community- and commercial-scale wind projects has widened during this time period. Recent bids from large projects < 8 ¢/kWh on 20-year levelized basis. Permitting and project attrition risks still apply.

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Qualifying wind projects assumed to elect the ITC in lieu of the PTC
  - For 750 kW and 1500 kW wind, ceiling prices calculated both with and without ITC
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 80% monetization of federal ITC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

ANAEROBIC DIGESTION

Est. of 15-year levelized contract: Anaerobic Digestion

Tech., class (kW)	2014 2nd Draft CP w/ITC/PTC + Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP No ITC/PTC, No Bonus
AD**, 50-3,000	17.70	18.55	19.55

Notes:

- ❑ Anaerobic digestion is still a fledgling market in New England.
- ❑ The most common opportunity for AD in RI is assumed to be for food waste digesters. Sludge or manure-based applications may also be possible.
- ❑ Project design and cost may vary widely by site.
- ❑Consistency in feedstock quantity and quality are important to long-term economics.

HYDRO

Est. of 15-year levelized contract: Hydro

Tech., class (kW)	2014 2nd Draft CP w/ITC/PTC + Bonus	2014 2nd Draft CP w/ITC/PTC, No Bonus	2014 2nd Draft CP No ITC/PTC, No Bonus
Hydro**, 50-1,000	17.25	17.90	18.85

Notes:

- Hydro is a mature market in New England.
- Few new projects, and no new impoundments, are anticipated.
- Expansions and new run-of-river installations are expected, however.
- Project design and cost may vary widely by site.

Sustainable Energy Advantage, LLC

10 Speen Street
Framingham, MA 01701
508.665.5850
www.seadvantage.com

Jason Gifford
tel. 508.665.5856
jgifford@seadvantage.com

APPENDIX

SOLAR

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (1)

Input category*

Expected Annual Average Net capacity factor, (%) DC

Proposed Input = 14.39%

2013 Input = 14.39%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost

Proposed Input = $2,900

2013 Input = $3,150/kW

Interconnection cost ($)

Proposed Input = $50/kW → $100/kW [National Grid project data: $179/kW]

2013 Input = $50/kW

O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations

Proposed Input = $20/kW-yr

2013 Input = $20/kW-yr

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (2)

Input category*

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.3%

2013 Input = 0.3% of total proj. costs

Project Management, Yr 1 ($/yr)

Proposed Input = $1,400/yr

2013 Input= $1,400/yr

Land Lease, Yr 1 ($/yr)

Proposed Input = $2,500/yr

2013 Input = $2,500/yr

Annual average escalation rate for O&M expenses (%)

Proposed Input = 3%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0% (covered in lease)

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = yr 1 = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M & financing inputs: Solar ≈ 150 kW dc (3)

Input category*
Debt-to-equity ratio
Proposed Input = 50/50
2013 Input = debt optimized to cash flow
Debt tenor (years)
Proposed Input = 13 yrs
2013 Input = 13 yrs
Interest rate on debt (%)
Proposed Input = 6.0%
2013 Input = 6.5%
Lender's Fee (% of loan amt)
Proposed Input = included in cap. cost
2013 Input = included in cap. cost
Avg. Debt Service Coverage Ratio Target
Proposed Input = 1.40
2013 Input = 1.40
After Tax Return on Equity (e.g. IRR) (%)
Proposed Input = 10%
2013 Input =12%
Decommissioning Reserve?
Proposed Input = $0
2013 Input = $0 (= salvage value)

*There was no 150kW CP for 2013. The 2013 100 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (1)

Input category

Expected Annual Avg. Net c.f. (%)

Proposed Input = 14.56%

2013 Input = 14.56%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost

Proposed Input = $2,550/kW

2013 Input = $2,650/kW

Interconnection cost ($)

Proposed Input = $200/kW → $250/kW [National Grid project data: $4/kW] [$1,080 for 260 kW solar installation]

2013 Input = $300/kW

O&M expenses (in $/kW$_{DC}$-year) in Year 1 of operations

Proposed Input = $20/kW-yr

2013 Input = $20/kW-yr

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (2)

Input category

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.3%

2013 Input = 0.3% of total proj. costs

Project Management, Yr 1 ($/yr)

Proposed Input = $6,500

2013 Input= $6,500/yr

Land Lease, Yr 1 ($/yr)

Proposed Input = $10,000

2013 Input = $15,000

Annual avg. escalation rate for O&M expenses (%)

Proposed Input = 3%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0%

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = yr 1 = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

Researched cost, O&M and financing inputs: Solar ≈ 400 kW dc (3)

Input category
Debt-to-equity ratio
Proposed Input = 50/50
2013 Input = debt optimized to cash flow
Debt tenor (years)
Proposed Input = 13 yrs
2013 Input = 13 yrs
Interest rate on debt (%)
Proposed Input = 5.5%
2013 Input = 6.0%
Lender's Fee (% of loan amt)
Proposed Input = included in cap. cost
2013 Input = included in cap. cost
Avg. Debt Service Coverage Ratio Target
Proposed Input = 1.35
2013 Input = 1.35
After Tax Return on Equity (e.g. IRR) (%)
Proposed Input = 10%
2013 Input = 11%
Decommissioning Reserve?
Proposed Input = $0
2013 Input = $0 (= salvage value)

*There was no 400kW CP for 2013. The 2013 500 kW inputs are shown here for comparison.

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%

2013 Input = 14.65%

Annual Production Degradation (%)

Proposed Input = 0.5%

2013 Input = 0.5%

Total installed cost ($/kW$_{DC}$), excluding Interconnection Cost

Proposed Input = $2,350/kW

2013 Input = $2,550/kW

Interconnection cost ($)

Proposed Input = $150/kW → $200/kW

[National Grid project data: MA projects average $107/kW; RI projects average $153/kW]

2013 Input = $150/kW

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

Input category

O&M expenses (in $/kW$_{DC}$-year) in Yr 1 of operations

Proposed Input = $15/kW-yr

2013 Input = $15/kW-yr

Insurance, Yr 1, (% of total project costs or $/yr)

Proposed Input = 0.25%

2013 Input = 0.25%

Project Management, Yr 1 ($/yr)

Proposed Input = $10,000

2013 Input= $10,000

Land Lease, Yr 1 ($/yr)

Proposed Input = $30,000

2013 Input = $34,500 to reflect tax on underlying land

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%

2013 Input = 3%

Royalties (% of Revenue, or $/yr)

Proposed Input = 0%

2013 Input = 0.0% (covered in lease)

Property Taxes ($ in Yr 1 and annual adjustment factor)

Proposed Input = same methodology/mil rate as 2013

2013 Input = 95% of $15/1000, basis declines by 5%/yr thereafter to floor of 30%

Debt-to-equity ratio

Proposed Input = 50/50

2013 Input = debt optimized to cash flow

Debt tenor (years)

Proposed Input = 13 yrs

2013 Input = 13 yrs;

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

Input category

Interest rate on debt (%)

Proposed Input = 5%

2013 Input = 5.5%

Lender's Fee (% of loan amt)

Proposed Input = included in cap. cost

2013 Input = included in cap. cost

Avg. Debt Service Coverage Ratio

Proposed Input = 1.35

2013 Input = 1.35

After Tax Return on Equity (e.g. IRR) (%)

Proposed Input = 10%

2013 Input =12%

Decommissioning Reserve?

Proposed Input = $200,000

2013 Input = $200,000

Additional Assumptions

- COD achieved in 2014
- Project Useful Life: 25 years
- 0.5%/yr production degradation
- Debt Service Coverage Ratio Target: 1.35X
- 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%
- *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 2013 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	12.13
17	2030	12.53
18	2031	12.94
19	2032	13.36
20	2033	13.79
21	2034	14.24
22	2035	14.7
23	2036	15.18
24	2037	15.67
25	2038	16.17

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% → 26.0%
2013 Input = 27.5%

Annual Production Degradation
Proposed Input = 0.5%
2013 Input = 0.5%

Total installed cost ($/kW), **excluding** Interconnection Cost
Proposed Input = $3,200/kW
2013 Input = $3,200/kW (excl. interconnection costs)

Typical Interconnection cost ($/kW)
Proposed Input = $100/kW → $150/kW [National Grid project data: MA avg = $99/kW; RI project = $120]
2013 Input = $100/kW

O&M expenses in Year 1 of operations
Proposed Input = $30/kW-yr
2013 Input = $30/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** **2013 Input = 0.3% of total project cost**
Project Management **Proposed Input = $15,000/yr** **2013 Input = $15,000/yr**
Land Lease, Year 1 ($/year) **Proposed Input = $20,000/yr** **2013 Input = $20,000/yr**
Annual avg. escalation rate for O&M expenses (%) **Proposed Input = 2.5%** **2013 Input = 2.5%**
Royalties **Proposed Input = included in lease exp.** **2013 Input = included in lease exp.**
Property Taxes ($ 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;** **2013 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;** **2013 Input = included in installed costs**
Debt-to-equity ratio **Proposed Input = 50/50** **2013 Input = debt optimized to cash flow**
Debt tenor (years) **Proposed Input = 15 yrs** **2013 Input = 15 Yrs.**
Interest rate on debt (%) **Proposed Input = 5.5%** **2013 Input = 5.5%**
Lender's Fee **Proposed Input = included in cap. cost** **2013 Input = included in cap. cost**
After Tax Return on Equity (e.g. IRR) (%) **Proposed Input = 12%** **2013 Input = 12%**
Decommissioning Reserve **Proposed Input = $0 (= salvage value)** **2013 Input = $0 (= salvage value)**

Additional Assumptions

- Commercial operation achieved in 2014
- Project Useful Life: 20 years
- Average Debt Service Coverage Ratio Target: 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%
- Market value of production (assumed revenue) post-contract = 90% of sum of ***wind-weighted*** energy and capacity price forecasts from 2013 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	11.01
17	2030	11.39
18	2031	11.78
19	2032	12.19
20	2033	12.61

ANAEROBIC DIGESTION

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Anaerobic digesters eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 90% monetization of federal PTC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- Commercial operation achieved in 2014
- Project Useful Life: 20 years
- Average Debt Service Coverage Ratio Target: 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%
- Market value of production (assumed revenue) post-contract = 90% of sum of energy and capacity price forecasts from 2013 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	11.35
17	2030	11.72
18	2031	12.10
19	2032	12.49
20	2033	12.90

HYDRO

Incentives

- Current Production Tax Credit (PTC) available to projects under construction as of 12/31/2013.
  - Hydro is eligible for 50% of face value
  - Ceiling prices calculated both with and without PTC extension.
- Ceiling prices evaluated with and without 50% Bonus Depreciation
- Ceiling prices evaluated assuming 90% monetization of federal PTC
- Benefit of Net Operating Loss at state level assessed both as generated and carry-forward. Proposed ceiling prices are an average of these two results.
- No federal, state, local or other grants assumed.

Additional Assumptions

- Commercial operation achieved in 2016
- Project Useful Life: 30 years
- 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%
- Market value of production (assumed revenue) post-contract = 75% of sum of energy and capacity price forecasts from 2013 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	11.49
17	2030	11.83
18	2031	12.18
19	2032	12.54
20	2033	12.90
21	2034	13.28
22	2035	13.67
23	2036	14.07
24	2037	14.49
25	2038	14.91
26	2039	15.35
27	2040	15.80
28	2041	16.26
29	2042	16.74
30	2043	17.23

2014 Distributed Generation Contracts Program – Recommended Megawatt Allocation Plan

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

November 27, 2013

2014 Program - Megawatts Available

- Scenario - 12.5 MW available for the 2014 DG Program.

- The capacity number will be subject to a final adjustment by the docket filing to the Public Utility Commission on December 16th.

- There could be additional MW made available in 2014. This will be dependent on the projects awarded contracts 2012 and 2013.

State of Rhode Island
Office of Energy Resources

2014 Allocation Plan - Recommendations

The OER will be recommending to the DG Board the following:

1. Establish an annual target, instead of a per enrollment target.

2. An annual target provides flexibility to the program, and was utilized with the 2011 and 2012 programs.

3. Maintain the rollover rule of kW for technologies from the 2013 DG program rules for the first 2 enrollments in 2014.

4. If there are no applications received in the final enrollment for a given technology/class, then those kW shall be committed to projects where there is the greatest demand.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

2014 Annual Goal

Technology	Eligible System Sizes	2014 Allocation	Potential Number of Projects	2011-2013 Contracts History
Small Solar	50-200 kW	400 kW	2-8	5
Medium Solar	201-500 kW	4,100 kW	9-22	10
Large Solar	501-1,000 kW	3,000 kW	3-6	6
Wind	50-1,500 kW	3,000 kW	1-2	2
Small Scale Hydropower	50-500 kW	1,000 kW	2	0*
Anaerobic Digestion	50-500 kW	1,000 kW	2	0
Total		12,500 kW		

2014 is the first year that small hydropower is eligible to participate.

State of Rhode Island
Office of Energy Resources

2014 - First Enrollment

Technology	Allocation
Small Solar (50-200 kW DC)	200 kW*
Medium Solar (201-500 kW DC)	1,400 kW
Large Solar (501-1,000 kW DC)	1,000 kW
Wind (50-1,500 kW)	1,500 kW*
Small Hydropower (50-500 kW)	500 kW*
Anaerobic Digestion (50-500 kW)	500 kW*
Total	5,100 kW

*These technologies allocations will be allowed to rollover until the 3rd enrollment.

If no applications are received in the last enrollment for a particular class, those kW will be awarded to projects where there is the greatest demand.

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

Additional Capacity in 2014 Program

- National Grid shall notify the OER and DG Board of any additional capacity that becomes available for the 2014 program.

- The DG Board in consultation with the OER will determine where that additional capacity is allocated to for the different technologies.

- Project demand and ceiling price results through the first two enrollments will determined where that additional capacity is allocated.

- National Grid and the OER shall notify the Public Utility Commission of any additional capacity added to the program prior to the last 2014 enrollment.

STATE OF RHODE ISLAND
OFFICE OF
ENERGY RESOURCES

Rhode Island Distributed Generation Standard Contracts Program:

Proposed Final Analysis & Data Submittal to DG Board and OER

December 2, 2013

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

SUMMARY RESULTS FROM CREST ANALYSIS

Summary Comparison of 2012, 2013 & 2013 CPs

Categories, 2012, in kW	2012 CP	Categories, 2013, in kW	2013 CP+	Categories, 2014, in kW	2014 *Proposed* CP+	Net Change 2013→2014
Solar, 501 – 5,000	28.95	Solar*, 501 +	24.95	Solar*, 500-3,000	23.50	-6%
Solar, 151 – 500	31.60	Solar*, 251 – 500	28.40	Solar*, 201-499	27.30	-4%***
Solar		Solar*, 101 – 250	28.80	Solar*, 50-200	27.10	-6%***
Solar, 10 – 150	33.35	Solar*, 50 – 100	29.95			
Wind	13.35	Wind*, 1,000-1,500	14.80	Wind*, 1,000-3,000	17.50	18%
Wind		Wind*, 400 – 999	16.20	Wind*, 50-999	16.20	0%
Wind		Wind*, 90 – 100	24.65			
AD		AD**, 400 – 500	18.55	AD**, 50-3,000	18.55	0%
Hydro		Hydro** 500-1,000	17.90	Hydro**, 50-1,000	17.90	0%

+ With ITC/PTC, No Bonus Depreciation
* ITC ** PTC
*** Note, changes in selected sub-class definitions prevents a direct comparison in these circumstances.

Summary Results: Sensitivity to Federal Incentives

Tech., class (kW)	2014 *Proposed* CP w/ITC/PTC + Bonus	2014 *Proposed* CP w/ITC/PTC, No Bonus	2014 *Proposed* CP No ITC/PTC, No Bonus
Solar*, 501-3,000	22.25	23.50	N/A
Solar*, 201-500	25.90	27.30	N/A
Solar*, 50-200	25.75	27.10	N/A
Wind*, 1,000-3,000	16.35	17.50	20.55
Wind*, 50-999	15.55	16.20	19.95
AD**, 50-3,000	17.70	18.55	19.55
Hydro**, 50-1,000	17.25	17.90	18.85

* ITC   ** PTC

Benchmarking to Other States

Nominal Levelized ¢/kWh (unless noted otherwise)	**RI (2013 CPs)**	**VT ('13 Bids/'12 SO)**	**CT (Sec. 127) (ZREC data next slide)**
Tech.↓ Terms→	**15 years** **Bundled**	**25 years (solar)** **20 years (others)** **Bundled**	**20 years** **Bundled**
Solar $_{\text{small}}$	29.95 (50-100kW) 28.80 (101-250kW)	20.50 (Bid)	
Solar $_{\text{Medium}}$	28.40		
Solar $_{\text{Large}}$	24.95	13.40 – 14.41 (Bid) (CP = 25.70)	East Lyme: 15.7 w/ 2% esc Somers: 19.0 w/ 3% esc Bridgeport: 33.36 flat
Wind $_{\text{Small}}$	24.65	25.30 (2012 Std Offer*)	
Wind $_{\text{Large}}$	14.80	11.82 (2012 Std Offer**)	BNE Wind Colebrook: 20.0 (avg. per 6/5/13 Order)
AD	18.55	14.11** * (2012 Std Offer)	
Hydro	17.90	12.26 (2012 Std Offer)	

* For 100 kW wind turbine; no small wind projects yet accepted into the program
** No large wind projects yet accepted into the program
*** Designed for Farm Digesters

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**	$90.43	$101.36	$102.31	$149.29
	4 accepted bids: 2 winners <500 kW	Winners span whole size range.	Winners range from 110 – 250 kW	Winners range from 101 – 250 kW
Approx. Value of Retail Electricity Purchases Avoided, Levelized*	$186		$186	
Est. Value Under 3rd-Party Net Metering (Assumed 10-15% discount, common in MA)	$158-167		$158-167	
Est. Equivalent to Calculated LCOE	$248-257		$260-269	

** UI Prices are for 2013 Solicitation* *** CL&P Prices are from 2012 Solicitation*

**** Levelization assumes 4% annual rate escalation and 10% discount rate. Based on UI GST Rate.*

Vermont Standard Offer

- Operating VT Standard Offer Projects (data through 9/24/2013)
  - Max eligible project size = 2.2 MW

Technology	# of Projects	Size Range (kW)
Solar	15	37 – 2,200
Wind	0	
Farm Methane	15	150 – 600
Hydro	3	138 – 675

APPENDIX A:

WIND MODELING ADJUSTMENTS & OPERATING WIND PROJECT DATA

WIND MODELING ADJUSTMENTS

Wind Modeling Adjustments for 2012 – 2014 CPs

Category	2012 Input	2013 Input	2014 Input (Draft)	2014 Input (Proposed Final)
Est. Annual Net Capacity Factor	25.0%	27.5%	26.0%	26.0%
Installed Cost (w/o Interconn.)	$2,750/kW	$3,200/kW	$3,200/kW	$3,200/kW
Interconnection cost estimate	$117/kW	$100/kW	$150/kW	$200/kW
Interest Rate on Term Debt	6.0%	5.5%	5.5%	6.5%
Monetization of Federal Tax Incentives	100%	90%	80%	80%
After Tax Return on Equity	13%	12%	12%	12%

OPERATING WIND PROJECT DATA:

SOURCE = MA CLEAN ENERGY CENTER, PRODUCTION TRACKING SYSTEM

Data Characteristics

- Coastal Massachusetts
  - Assumed to be closest wind resource and topographic match to Rhode Island
  - All projects except one are southeastern MA (SEMA Zone)
  - One from north shore (NEMA Zone)
- At least 12 months of production data required
  - Assume first 6 to 12 months should always be filtered out due to standard start-up issues and turbine break-in period.
- Other considerations
  - When limited data available, should compare to long-term averages → does available data set represent a good or bad year?

Wind Production Data
Source = MassCEC Production Tracking System (PTS)

Project	Location	Net capacity factor (%), based on Mass CEC PTS
MA Military Reservation #1 (US Air Force)	Bourne & Falmouth, MA (Cape Cod)	~23%
Scituate Wind LLC	Scituate, MA (Southeastern MA)	~28%
Ipswich Municipal Light Plant	Ipswich, MA (Northeastern MA)	~25%
NOTUS Clean Energy	Falmouth, MA (Cape Cod)	~32%
Hull Wind 2	Hull, MA	~26%
Town of Kingston	Kingston, MA	~20%
MA Military Reservation #2 & #3 (US Air Force)	Bourne & Falmouth, MA (Cape Cod)	~26%

Projects Not Included in Dataset

Project	Location	Reason for Exclusion
MWRA Deer Island	Winthrop, MA	Tower height restriction due to proximity to Logan Airport (CF < 20%)
Jiminy Peak	Hancock, MA	Inland location, higher elevation than available in RI (CF > 32%)
Falmouth Wind 1 & 2	Falmouth, MA	Curtailed operations imposed by pending litigation
Lightolier	Fall River, MA	Less than 12 months of available data
Fairhaven Wind LLC	Fairhaven, MA	Curtailed operations imposed by pending litigation
MWRA DeLauri Pumping Station	Charlestown, MA	Production data not included in PTS
Templeton Municipal Light Plant	Templeton, MA	Inconsistent data/operating history
Princeton Municipal Light Plant	Princeton, MA	Inconsistent data/operating history
Mount Wachusett Community College	Gardner, MA	Production data not included in PTS
No Fossil Fuels LLC	Kingston, MA	Production data not included in PTS
Berkshire Wind	Hancock, MA	Inland location, higher elevation than available in RI (CF > 40%)

Other Resources

- LBNL/Bolinger 9/12 Presentation:
  Is Class 2 the New Class 5?

2014 DISTRIBUTED GENERATION CONTRACTS PROGRAM – SUMMARY AND RECOMMENDATIONS

Office of Energy Resources

Monday, December 2, 2013

2014 Program Development

- With approval from the Distributed Generation Standard Contracts Board (DG Board) the Office of Energy Resources (OER) contracted with Sustainable Energy Advantage (SEA) in August to develop the 2014 ceiling prices.
- SEA developed the ceiling prices in 2011, 2012 and 2013.
- The OER and DG Board hosted 4 public meetings on the development of the ceiling prices and the proposed megawatt (MW) allocation plan.
- In addition to the public meetings posted on the R.I. Secretary of State website, the OER notified stakeholders of all upcoming meetings.

2014 Ceiling Prices

- SEA developed ceiling prices for wind, solar, anaerobic digestion and small scale hydropower.
- SEA provided public comment on the proposed system sizes being used in the development of ceiling prices for each technology.

SEA Ceiling Price Results

1. The solar ceiling prices decreased by 4 and 6 percent amongst the solar classes.
2. Anaerobic digestion and small scale hydropower ceiling prices remained the same as in 2013.
3. The wind ceiling price increased by 18 percent from 2013.

Wind Ceiling Price

- SEA made the following adjustments to the wind ceiling price for 2014, which resulted in the ceiling price increase:

- Increased the interconnection costs
- Reduced the capacity factor
- Increased the interest rate on term debt
- Reduced the monetization of federal tax incentives

Megawatt Allocation Plan

- The OER developed a tentative 12.5 MW allocation plan scenario.
- The final MW allocation plan will depend on whether capacity may be remaining from the 2013 program.
- Additional MW capacity may be added if the awarded contracts from 2012 and 2013 aren't operational by their contractual deadlines.

Megawatt Allocation Plan

The OER considered the following factors when developing the MW allocation plan:

1. Increases and decreases to the ceiling prices from 2013.

2. Actual proposed and awarded contract prices from 2013.

3. Program expansion from 3 technologies to 4. (small scale hydropower)

4. Market response and competition over the first 3 years of the program.

5. Availability of the federal renewable energy incentives in 2014. The Production/Investment Tax Credits and Bonus Depreciation will both expire on December 31, 2013.

6. The federal Investment Tax Credit is available for solar through 2016.

7. Allocating a fair portion of the MW capacity to support each of the technologies.

2013 and 2014 - Allocation Comparison

Technology	Eligible System Sizes	2013 Allocation	2014 Tentative Allocation	2014 Potential Number of Projects	2011-2013 Contract History*
Small Solar*	50-200 kW	900 kW	400 kW	2-8	5
Medium Solar*	201-500 kW	3,000 kW	4,100 kW	9-22	10
Large Solar	501-1,000 kW	3,900 kW	3,000 kW	3-6	6
Wind	50-1,500 kW	4,500 kW	3,000 kW	1-2	2
Small Scale Hydropower*	50-500 kW	0	1,000 kW	2	0*
Anaerobic Digestion	50-500 kW	1,500 kW	1,000 kW	2	0
Total		13,800 kW	12,500 kW		

*Small and medium solar target classes are being adjusted from 2013 to 2014.

*2014 is the first year that small scale hydropower is eligible to participate.

*Contract History does not include the final 2013 enrollment.

Megawatt Allocation Plan

The OER recommends the following for the 2014 allocation plan:

1. Establish an annual target, instead of a per enrollment target.

2. An annual target provides flexibility for the program, and was utilized with the 2011 and 2012 programs.

3. Maintain the MW rollover rule for technologies from the 2013 DG program rules for the first 2 enrollments in 2014.

4. If there are no applications received in the final enrollment for a given technology/class, then that capacity shall be committed to other technologies.

5. The adjusted allocations in the final enrollment will be based on market demand and ceiling prices results from the first 2 enrollments amongst the technologies

6. The final enrollment rules would also apply to any 2012 or 2013 contracts that fail to become operational.

Questions/Comments