Rhode Island Distributed Generation Board

SURVEY TO INFORM 2022 CEILING PRICE DEVELOPMENT

DUE DATE: Friday, August 20, 2021

Dear Renewable Energy Industry Participants:

The Rhode Island Office of Energy Resources and Distributed Generation Board seek your input into the development of ceiling prices for renewable energy projects under the Renewable Energy Growth (REG) Program for the 2022 Program Year. OER and the DG Board have an obligation to submit ceiling price recommendations to the RI Public Utilities Commission intended to support viable and cost-effective projects. Receiving current information from market participants is critical to developing robust, accurate, and defensible ceiling price recommendations.

Given the unprecedented environment due to COVID-19, as well as the natural evolution of market conditions and the experience with the DG Standard Contracts (SC) and REG programs to date, the DG Board and OER seek your feedback on several topics related to Ceiling Price development for the 2022 Program Year (beginning April 1, 2022). OER requests descriptive explanations and source materials to complement the quantitative data provided in response to the Data Request.

Feel free to respond to as many of the following questions as you are able. Please be specific with your comments, recommendations and sources. Use as much room as you need. You may also save your responses and come back to complete the survey at a later time if you are interrupted.

This survey is your primary opportunity to provide written comments and recommendations, as well as evidence to substantiate your comments and recommendations. Additional opportunities will also exist for both written comments and participation in public meetings. In general, the absence of a response to any of these questions will be treated as support for the current policy design.

As has been the case in prior years, the 2022 Ceiling Prices must ultimately be approved by the Rhode Island Public Utilities Commission (PUC) after thorough review and comment by the Commissioners, Commission staff and the Division of Public Utilities and Carriers, Rhode Island's official advocate for electric ratepayers. In anticipation of this review, we note that it is highly unlikely that we would incorporate suggested changes to the recommended Ceiling Prices that are not supported by substantial and credible evidence, or could be inconsistent with state laws, rules and tariffs governing the REG Program already approved by the General Assembly and/or the PUC. While we welcome the opportunity to receive and vet all stakeholder feedback, our flexibility in incorporating said stakeholder feedback is not absolute.

All Survey responses are voluntary and will be kept confidential in accordance with the State's Access to Public Record Act. Any information provided in response to this Survey will not be identified in relation to, or attributed to, an individual respondent in any public presentation or public document.

If you have any questions about how to complete this survey, please contact Jim Kennerly at jkennerly@seadvantage.com or (508) 665-5862 and/or Toby Armstrong at tarmstrong@seadvantage.com or (508) 665-5864.

Respondent Information

* 1. Please provide your name and contact information:

Name

Company

Email Address

Phone Number

2. How do you expect COVID to impact projects proposed in Program Year 2022, as well as related supply chains? Please describe in detail and substantiate with documentation to Jim Kennerly at jkennerly@seadvantage.com and Toby Armstrong at tarmstrong@seadvantage.com.

3. What types of projects are you involved with? You may add multiple responses.

- [ ] Small Solar (under 25 kW)
- [ ] Medium, Commercial and/or Large Solar (>25 kW-5,000 kW)
- [ ] Non-Solar (Wind, Hydroelectric, Anaerobic Digestion)

4. In past years of the REG Ceiling Price analysis, the Total Installed Capital Cost estimates have been based on quartiles and averages obtained from databases of projects participating in state programs in MA, CT, NY, and quotes from EnergySage. However, MA now only publishes data associated with completed projects, which only allows for use of such data for projects less than or equal to 25 kW. Is there any reason for the consulting team not to use other available state data sources in Program Year 2022?

If so, please provide documentary data and evidence to substantiate your claim to Jim Kennerly at jkennerly@seadvantage.com and Toby Armstrong at tarmstrong@seadvantage.com.

Small Solar Screening Question

5. Are you involved with Small Solar (under 25 kW)?

- Yes
- No (skip this section)

Small Solar (under 25 kW) Questions

6. The table below contains the current 2022 Ceiling Price analysis financing assumptions for Small Solar projects.

NOTE #1: The after-tax equity IRRs shown above reflect a levered value (i.e., the project's net return after paying its debt obligations), to ensure consistency with the inputs to the Cost of Renewable Energy Spreadsheet Tool (CREST) model used to calculate the Ceiling Prices.

NOTE #2: These values are subject to change based on further evidence, research, analysis and stakeholder feedback.

If you believe any of the above inputs should be changed, please enter in your recommended input into the boxes below. For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be revised, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Small I - % Debt	
Small I - Debt Term	
Small I - Interest Rate on Term Debt	
Small I - Lender's Fee	
Small I - Target After-Tax Equity IRR	
Small II - % Debt	
Small II - Debt Term	
Small II - Interest Rate on Term Debt	
Small II - Lender's Fee	
Small II - Target After-Tax Equity IRR	

7. The table below contains the 2022 Ceiling Price analysis production and cost assumptions for Small Solar projects.

If you believe any of the above inputs should be changed, please enter in your recommended input into the boxes below. **Please specify if the change would apply to Small Solar I, II, or both.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you disagree with, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

Any responses that are not provided in units consistent with units utilized the table above will not be accepted.

Fixed O&M

O&M Escalation Factor

Non-O&M Escalation Factor (e.g., site lease, insurance, project mgmt, etc)

Insurance (% of cost)

Project mgmt ($/yr)

Site Lease ($/yr)

8. In your experience, what is the market share (% of total) in Rhode Island of customers financing a 1-15 kW system purchase with:

Home equity loans/lines of credit

Specially-designed solar loans

Cash

Other debt (please specify)

9. What is the typical duration (in years) of home equity loans in Rhode Island for systems 1-15 kW?

10. What is the typical duration (in years) of solar loans in Rhode Island for systems 1-15 kW?

11. What are the typical interest rates (in percentage terms) for home equity loans in Rhode Island for systems 1-15 kW?

12. What are typical interest rates for solar loans in Rhode Island for systems 1-15 kW?

13. What are the total fees (expressed as a percentage of the total loan amount) typically charged by the lender to a solar PV system 1-15 kW?

14. Are lender fees usually accounted for separately from the loan principal, or are they rolled into the principal itself?

- Accounted For Separately
- Rolled into Principal
- Other (please specify)

15. What percentage of projects from 15-25 kW are:

Purchased 100% with cash

Financed 100% with debt

A mix of cash and debt

16. For customers utilizing a mix of cash and debt, what percentage of cash is typical?

17. What kind of debt do 15-25 kW projects usually utilize? What are typical durations (in years), interest rates, and fees associated with this debt?

Type of debt:

Typical Duration:

Typical Interest Rates:

Fees:

18. We currently assume year-over-year capital cost declines of 3.5% for Small Solar I and Small Solar II. Do you agree or disagree with the cost decline assumptions? (Note that the consulting team is not considering eliminating any cost decline assumption, but rather seeking feedback on the magnitude of the expected decline.)

If you disagree, please specify a more reasonable assumption to expect for changes in capital equipment costs from 2021 to 2022? What is your basis and evidence for that expectation? Submit all relevant documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

- Agree
- Disagree (please specify)

19. Do you assume the eventual installation of paired energy storage prior to the end of your project's useful life?

- Yes
- No

20. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

21. **(if yes to storage)** What year (1-25) do you assume it will be installed?

22. **(if yes to storage)** How much (in $/kWDC of the solar facility) do you assign as the upfront capital cost of the installation?

23. **(if yes to storage)** How much (in terms of $/kW-yr of the solar facility) do you assign as the ongoing operating costs of the installation?

24. **(if yes to storage)** Please describe your operating life assumption (in years) for the paired energy storage project.

25. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

Solar >25 kW Screening Question

26. Are you involved with solar over 25 kW?

- ◯ Yes
- ◯ No (skip section)

Solar Projects Greater than or Equal to 25 kW: Capital Cost, Operating Cost & Financing Assumptions

27. Copied below are the solar cost and production modeling inputs used in the approved 2021 Ceiling Prices calculations for Solar projects. Please reference the table as you answer the questions below.

O&M costs should reflect all fixed and variable expenses associated with project operations, EXCEPT annual expenses for insurance, property taxes, land leases, royalties, and project management.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. **For each recommended change, note which project categories (e.g., Medium) the change should apply to.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Fixed O&M	
O&M Escalation Factor	
Non-O&M Operating Expense (e.g., insurance, project mgmt, land lease etc) Escalation Factor	
Insurance	
Project Management	
Site Lease	

28. The table below shows our proposed 2022 RI REG financing assumptions for Solar projects.

NOTE #1: The after-tax equity IRRs shown above reflect a levered value (i.e., the project's net return after paying its debt obligations), in order to ensure fidelity with the inputs to the Cost of Renewable Energy Spreadsheet Tool (CREST) model used to calculate the Ceiling Prices.

NOTE #2: These values are subject to change based on further evidence, research, analysis and stakeholder feedback.

Are there any proposed 2022 Solar REG assumptions that you find to be outside the normal range? If so, please identify them and propose an alternative assumption. **For each recommendation, state which category of projects (e.g., Medium) it should apply to.**

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

% Debt	
Debt Term (years)	
Interest Rate on Term Debt	
Lender's Fee (% of total borrowing)	
% Equity Share of Sponsor Equity	
Target After-Tax Equity IRR (Sponsor Equity, Levered Return)	
% Equity Share of Tax Equity	
Target After-Tax Equity IRR (Tax Equity, Levered Return)	
Depreciation Approach	

29. For Solar projects, we currently assume that only the most creditworthy borrowers are eligible for loan terms beyond 15 years, and therefore modeling a loan term over 15 years would not accurately reflect a value that is appropriate to the market as a whole. Do you agree or disagree with this assumption?

If you do not agree, please explain what debt term we should assume instead as a reasonable proxy for the market as a whole.

- Agree
- Disagree (please specify)

30. We currently assume year-over-year capital cost declines 4.5% for all solar categories over 25 kW. Do you agree or disagree with the cost decline assumptions? (Note that the consulting team is not considering eliminating any cost decline assumption, but rather seeking feedback on the magnitude of the expected decline.)

If you disagree, please specify a more reasonable non-zero assumption to expect for changes in capital equipment costs from 2021 to 2022? What is your basis and evidence for that expectation? Submit all relevant documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com.

- Agree
- Disagree (please specify)

31. We currently assume (based on previous market participant feedback) that competition and market conditions have applied downward pressure to sponsor equity returns for Solar projects in recent years, and that these conditions have (and will continue) to assert themselves as the COVID-19 pandemic subsides. If you do not agree with this assumption, please compare sponsor equity target returns between 2020 and 2021 with expected sponsor equity target returns for Program Year 2022 and provide the source or other basis for your comparison.

32. We also currently assume (based on previous market participant feedback) that tax equity investors in Solar projects continue to lack the tax capacity to elect 100% bonus depreciation and continue to utilize the five-year schedule of the Modified Accelerated Cost Recovery System (MACRS) for depreciation. Would you agree with this assumption? Why or why not? If you do not agree, please explain what we should assume instead.

33. What percentage of projects that you encounter have investors that are not able to fully leverage both 5-year MACRS and the federal Investment Tax Credit (ITC) in the year that said benefits are generated?

5-year MACRS

ITC

Questions Regarding Returns to Scale for Solar Projects >25 kW

34. It is well known that as the system scale of a solar PV project increases, the unit costs decline with increasing returns to scale. In the text boxes below, please note **the point(s) within between 25 kW and 5000 kW** that capital and operating costs begin to drop (on a unit basis) resulting from increasing returns to project scale. Please notes as many points as you feel accurately reflects inflection points for project economics, but no more than five for each cost category (Please also note, as applicable, if any of these costs do not substantially decline with increased system scale within this size range).

Upfront Capital Costs - Inflection point 1

Upfront Capital Costs - Inflection point 2

Upfront Capital Costs - Inflection point 3

Upfront Capital Costs - Inflection point 4

Upfront Capital Costs - Inflection point 5

Non-Capital Operating Costs - Inflection point 1

Non-Capital Operating Costs - Inflection point 2

Non-Capital Operating Costs - Inflection point 3

Non-Capital Operating Costs - Inflection point 4

Non-Capital Operating Costs - Inflection point 5

Solar Projects Greater than or Equal to 25 kW: Post-Tariff Assumptions

35. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, what do you see as your principal sources of revenue following the expiration of the term of your REG tariff term? Note, under current law, Net Metering is not available for projects participating in the REG program. Please indicate how much, in $/MWh, you expect to receive (and include in your pro forma) from these sources of revenue from the end of the tariff term until the end of the project's expected useful life.

Capacity ($/MWh)

RECs ($/MWh)

Energy ($/MWh)

Ancillary Serv. ($/MWh)

Other - please specify ($/MWh)

36. Do you assume the eventual installation of paired energy storage prior to the end of your project's useful life?

- Yes
- No

37. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

38. **(if yes to storage)** What year (1-25) do you assume it will be installed?

39. **(if yes to storage)** How much (in $/kWDC of the solar facility) do you assign as the upfront capital cost of the installation?

40. **(if yes to storage)** How much (in terms of $/kW-yr of the solar facility) do you assign as the ongoing operating costs of the installation?

41. **(if yes to storage)** Please describe your operating life assumption (in years) for the paired energy storage project.

42. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

43. When sizing the inverter for projects you submit into the REG program, what DC-AC ratio range do you typically employ? Please explain your reasoning for this DC-AC sizing ratio.

Medium Solar (25-250 kW)

Commercial Solar (251-999 kW)

Large Solar (1-5 MW)

44. Do you plan to replace your project's inverter?

- Yes
- No

45. **(if yes to inverter replacement)** Please indicate the year in which you assume that you will replace your project's inverter (e.g., year 10)

46. **(if yes to inverter replacement)** Would you consider replacing the project's inverter with a smaller inverter?

- Yes
- No

47. **(if yes to inverter replacement)** To what DC-AC ratio would you consider sizing your inverter to, upon replacement of the inverter? Please explain your reasoning for over-sizing the project's output to its inverter.

Medium (25-250 kW)

Commercial (251-999 kW)

Large (1-5 MW)

48. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, how long (in years) do you assume projects will operate prior to their decommissioning?

49. Do you assume replacement of some or all the project's generation equipment?

- Yes
- No

50. **(if yes to equip. replacement)** What percentage of the project's generation capacity would you assume that you will replace?

51. **(if yes to equip. replacement)** Please provide your estimate of the useful life of this repowered equipment, as well as the change in capacity factor that the replacement equipment will provide (e.g., will change solar panels after 20 years, and expect to increase DC capacity factor from 12% in year 20 to 15% in year 21)

Useful life (in years)

Change in Capacity Factor

Non-Solar Screening Question

52. Are you involved with non-solar projects (Hydro, Wind, AD)

- ◯ Yes
- ◯ No (skip section)

Non-Solar (Hydro, Wind, AD)

53. Copied below are the non-solar cost and production modeling inputs used in the approved 2021 Ceiling Prices calculations for Wind, Hydroelectric, and Anaerobic Digestion projects. Please reference the table as you answer the questions below.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. **For each recommended change, note which project categories (e.g., Hydro) the change should apply to.** For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Note that we are not asking for feedback on total cost inputs, as they are derived from an analysis of recent installed cost data.

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

Nameplate Capacity (e.g., typical sized project modeled for the category)

Capacity Factor

Annual Degradation

Fixed O&M

O&M Inflation

Insurance

Project Management

Site Lease

54. The table below shows our proposed 2022 RI REG financing assumptions for Non-Solar projects.

If you believe any of the aforementioned inputs should be changed, please enter in your recommended input into the boxes below. For each recommended change, note which project categories (e.g., Hydro) the change should apply to. For any input that you believe to be reasonable (should remain unchanged), please leave the text box blank.

For assumptions that you think should be changed, please provide more reasonable costs, supported by documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com (such as a properly-redacted quote or contract for O&M services).

Any responses that are not provided in units consistent with units utilized in the table above will not be accepted.

% Debt

Debt Term (years)

Interest Rate on Term Debt

Lender's Fee (% of total borrowing)

% Equity Share of Sponsor Equity

Target After-Tax Equity IRR (Sponsor Equity, Levered Return)

% Equity Share of Tax Equity

Target After-Tax Equity IRR (Tax Equity, Levered Return)

Depreciation Approach

55. For Non-Solar projects, we currently assume that only the most creditworthy borrowers are eligible for loan terms beyond 15 years, and therefore modeling a loan term over 15 years would not accurately reflect a value that is appropriate to the market as a whole. Do you agree or disagree with this assumption?

If you do not agree, please explain what debt term we should assume instead as a reasonable proxy for the market as a whole.

- Agree
- Disagree (please specify)

56. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, how long do you assume projects will operate prior to their decommissioning?

57. Do you assume replacement of some or all the project’s generation equipment?

- Yes
- No

58. **(if yes to equip. replacement)** What percentage of the project’s generation capacity would you assume that you will replace?

59. **(if yes to equip. replacement)** Please provide your estimate of the useful life of this repowered equipment, as well as the change in capacity factor that the replacement equipment will provide (e.g., will change solar panels after 20 years, and expect to increase DC capacity factor from 12% in year 20 to 15% in year 21)

Useful life (in years)

Change in capacity factor

60. When your firm seeks financing for projects you bid into Renewable Energy Growth program Open Enrollments, what do you see as your principal sources of revenue following the expiration of the term of your REG tariff term?

Note, under current law, Net Metering is not available for projects participating in the REG program.

Please indicate how much, in cents/kWh, you expect to receive (and include in your pro forma) from these sources of revenue from the end of the tariff term until the end of the project’s expected useful life.

Capacity ($/MWh)

RECs ($/MWh)

Energy ($/MWh)

Ancillary Serv. ($/MWh)

Other ($/MWh)

61. Do you assume the eventual installation of paired energy storage (e.g. to participate in organized markets following the expiration of your initial tariff term or for other reasons)?

- Yes
- No

62. **(if yes to storage)** How would you size said energy storage project (in terms of rated power and hours of discharge)?

63. **(if yes to storage)** What year (1-25) do you assume it will be installed?

64. **(if yes to storage)** How much ($/kWDC of the generation facility) do you assign as the upfront capital cost of the installation?

65. **(if yes to storage)** Please describe how much (in $/kWh and/or $/kW, as may be necessary) you assume in terms of post-tariff revenue as a result of installing energy storage.

CRDG Screening Question

66. Is your firm actively engaged in developing Community Remote Distributed Generation (CRDG) projects into forthcoming Rhode Island Renewable Energy Growth program Open Enrollments?

- Yes
- No (skip section)

Community Remote Distributed Generation (CRDG)

67. Do you use a 3rd party to enroll customers? If so, please describe your relationship with this third party. If not, please simply write “No” or “N/A”.

68. Does your firm target residential customers to be offtakers of your CRDG projects?

- Yes
- No

69. **(if yes to resi. offtake)** Do you specifically target or market to customers on National Grid’s income-qualified (A-60) rate class? Why or why not?

70. **(if yes to resi. offtake)** Would your answer to the previous question change if National Grid were to become the central entity for enrolling income qualified customers on the A-60 rate schedule? Why or why not?

71. Does your firm target Commercial customers to be offtakers of your CRDG projects?

- Yes
- No

72. **(if yes to comm. offtake)** Please describe how your firm (or a 3rd party) targets such customers.

73. Does your firm aim to recruit "anchor tenant" customers that contract for a large share of the project's offtake? If so, please explain why you utilize this approach.

74. **(if yes to "anchor tenant")** Please explain the impact an anchor tenant has on the project in comparison to one in which the project's offtake is assigned entirely to residential customers.

75. In a hypothetical scenario in which National Grid were to become the central entity for enrolling some or all the CRDG customers, would your firm change the way in which it approaches the CRDG market? Why or why not?

76. Would requiring National Grid to be the central entity for enrolling some or all CRDG customers affect any existing, expected or potential contractual or other long-standing business arrangements? Why or why not?

77. Please explain any other ways in which making National Grid the central entity for enrolling some or all CRDG customers would affect your business and/or your participation in the CRDG market segment.

Additional Questions Regarding Community Remote Distributed Generation (CRDG)

Preamble: Under the Renewable Energy Growth Act, the Ceiling Prices for CRDG projects (to which capacity allocations are extended to Commercial Solar, Large Solar, and Wind projects) cannot be more than 15% higher than for similarly situated non-CRDG renewable energy classes. In simple terms, the categories of cost can be separated into upfront customer acquisition costs (functionally, a capital cost incurred prior to year 1) and ongoing customer management and care (functionally, an operating expense incurred from Year 1 to the end of the project's life). It is our team's understanding, based on market participant information, that upfront customer acquisition costs average to approximately $100/kWDC while the cost of ongoing customer management and care is $22/kWDC-yr.

78. Do you believe the assumptions of $100/kWDC for upfront customer acquisition is accurate for Commercial Solar CRDG projects (ranging from 251-999 kW DC)?

- ◯ Yes
- ◯ N/A (not a solar developer)
- ◯ No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

79. Do you believe the assumptions of $22/kWDC-yr for ongoing customer management and care is accurate for Commercial Solar CRDG projects (ranging from 251-999 kW DC)?

- ◯ Yes
- ◯ N/A (not a solar developer)
- ◯ No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

80. Do you believe the assumption of $100/kW DC for upfront customer acquisition is accurate for Large Solar CRDG projects (ranging from 1-5 MW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

81. Do you believe the assumption of $22/kWDC-yr for ongoing customer management and care is accurate for Large Solar CRDG projects (ranging from 1-5 MW DC)?

- Yes
- N/A (not a solar developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

82. Do you believe the assumption of $100/kW DC for upfront customer acquisition is accurate for Wind CRDG projects (ranging from 0-5 MW DC)?

- Yes
- N/A (not a wind developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

83. Do you believe the assumption of $22/kW-yr for ongoing customer management and care is accurate for Wind CRDG projects (ranging from 0-5 MW DC)?

- Yes
- N/A (not a wind developer)
- No - Please provide a different assumption in $/kW DC in the text box below, and forward any appropriate documentation to jkennerly@seadvantage.com and tarmstrong@seadvantage.com. **NOTE: Alternative values without documentation (and/or not provided in $/kWDC) will not be utilized in adjusting this assumption.**

Community Remote Distributed Generation (CRDG)

84. In a hypothetical scenario in which National Grid were to become the central entity for enrolling some or all CRDG customers, would this cause you to consider participating in the CRDG program? Why or why not?