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July 21, 2014

Mr. Anthony M. Star
Director
Illinois Power Agency
160 N. LaSalle Street, Suite C-504
Chicago, IL 60601

Re: IPA Request for Comments Related to the Distributed Generation REC Procurement Process

Dear Anthony:

We are writing in response to the IPA's Request for Comments surrounding the Distributed Generation ("DG") portion of the 2015 Procurement Plans.

New Grid Energy Solutions is a renewable energy consultancy and project development company serving the commercial and government markets.

As a consultancy, New Grid provides services for some of the nation's largest project developers and financiers in the areas of policy, project finance, system design, and wholesale electricity markets.

As a project developer/installer, New Grid designs and installs renewable energy systems- primarily photovoltaic, solar thermal, and hybrid photovoltaic-thermal ("PVT")- in the mid-Atlantic and Chicagoland regions.

With this background combination, we hope that our responses to the questions below prove to be of value to the IPA as it continues to evaluate how to best implement the DG portion of the 2015 Procurement Plans.

Should you have any questions or comments, please feel free to call New Grid at (312) 698-3558.

Sincerely,

Mark Raeder
Principal

Questions

1. For DG between 25 kW and 2 MW in nameplate capacity, should the IPA consider holding procurements for more than one size range category? Are there other attributes that should be considered (e.g., net metering eligibility, community solar projects, residential/non-residential) in determining procurement categories?

Yes. Between 1 kW and 25 kW the economies of scale benefits increase relatively rapidly. After 25 kW, they continue to do so, but at a decreasing rate.

In addition, we estimate a system size of approximately 500 kW AC to be the minimum that most 3rd party financiers of projects will consider financing as a standalone investment. Below this size, consideration for 3rd party financing often requires bundling multiple projects into a portfolio, adding cost and complexity.

Therefore, New Grid recommends that separate procurements be held for systems between 25 kW and 500 kW AC and for systems above 500 kW AC.

2. How should the IPA define a distributed generation system? Is size of a system defined at the inverter, at the meter, or in some other way?

At the meter for simplicity and to allow for systems with multiple central inverters or string inverters. Also 1 system per facility/location seems like a reasonable restriction to avoid large, separately-metered systems at the same location from gaining a disproportionate share of RECs.

3. If the IPA holds separate procurements for new and existing systems, how should those terms be defined? For example, is a system under development but not in operation at the time of the procurement new or existing? If RECs procured from new systems are anticipated to be of higher value than those from existing systems, what can the IPA consider that will prevent the procurement process from having a short-term impact on project development?

Since a large portion of the funds were originally intended to be available for over a year now, we find it reasonable that systems that either were developed, or are being developed, under the framework of a broken RPS program be allowed to participate in the procurement. We recommend that the date for differentiating between existing and new systems be June 28, 2014, the date on which the Procurement Plans legislation was signed, and that existing systems must have been commissioned after June 30, 2013.

4. How long and what flexibility should the IPA allow for new systems to commence operation after the procurement event?

1 year for commercial operation status for systems with additions of 3-6 months where deemed appropriate.

5. What are the advantages and disadvantages of REC contracts of five year terms and those of a longer duration? Please be specific by market segment/size, and between new and existing systems.

5-year contract terms will provide the most value in terms of the time value of money and provide the best combination of expediting the development of projects and reducing the chance for changes in state legislation to affect program funding levels.

6. What are the trade-offs between contract terms for new systems that pay for RECs as they are delivered versus contract terms that would allow for some upfront payment upon the system going into operation, but with commensurate enhanced credit requirements and clawback provisions?

REC payments made upfront based on a defined production estimate process are most suitable for the residential (under 25 kW) sector of the procurement program. Along with suitable clawback provisions and credit requirements, the reduction in administrative time and cost outweighs the potentially negative effects of this structure.

For larger systems over 25 kW, the potentially negative effects upfront payments, such as production overestimation, may result in an artificially high number of RECs being offered and an artificially low clearing price. Therefore, we recommend a 5-year contract term for larger projects.

7. What elements may be necessary to include in clawback provisions to ensure that Agency, ratepayer, and stakeholder interests are properly protected?

Letters of intent and/or proof of site control; a site plan; and proof of deposit payment should be considered as safeguards. Other milestones that may be worth consideration to avoid phantom projects are proof of major equipment delivery or a measurement of substantial system construction (i.e. 20% of construction financing costs spent).

8. What are the perceived risks that developers, property owners, lending institutions, utilities, utility ratepayers, and other stakeholders may be exposed to as a consequence of the IPA entering into REC procurement contracts with terms of more than 5 years?

Risk of further interruptions in program implementation due to future state legislation could drive up the cost of capital for developers, and the decrease in the time value of longer term payments would likely result in less solar procured under the fixed program budget.

9. What credit requirements may be appropriate for aggregators and other counterparties (i.e., self-aggregating system owners)? Should these requirements vary based on REC portfolio size and system size? If so, how?

Credit requirements for aggregators/owners should be sufficient enough that, in combination with the deposit payment and clawback provisions, the interest of the program and rate payers are protected without being overly cumbersome.

10. Are there timing considerations other than those related to DCEO rebates, state and federal tax incentives that the IPA should consider?

None significant enough to warrant delaying the procurement process. The sooner it is initiated the better.

11. If aggregators are allowed to bid speculatively (e.g., not all projects in their aggregation identified at the time of bidding), what would be a reasonable length of time for aggregators to be given to provide evidence of viable projects, and what provisions should be considered to reallocate quantities of RECs to other aggregators if an aggregator is not able to verify progress on project development?

Purely speculative bidding could result in tying up a significant amount of funds. 4-6 months for projects not specifically identified upon bidding should be the maximum if speculative bidding is allowed . Afterwards, unused funds can be allocated to a waiting list.

12. What additional provisions, if any, should be included to allow entities to be their own aggregator?

A simply defined measure of creditworthiness, or simply the use of sufficient clawback provisions and the deposit monies.

13. Given the framework of the Illinois RPS and provisions of the new Section 1-56(i), what models from other states should the IPA consider? Are there aspects of other state's models that the IPA should be aware of to avoid, and why?

Connecticut, Massachusetts, New York and District of Columbia (for its aggressive solar carve-out target and inclusion of solar thermal)

14. Should the IPA consider tracking RECs using systems other than PJM-GATS and M-RETs?

No. PJM-GATS and M-RETS are sufficient.

15. Are there policies and procedures for tracking DG RECs (e.g., system certification) that need updating under current M-RETs and PJM-GATs frameworks?

None that come to mind.

16. Participants in our June 12th workshop included project developers, solar installers, both local and national businesses, utilities, trade associations, environmental organizations, consumer advocacy groups, and state agencies. Are there additional entities (or categories of entities) that should be engaged in this process?

This seems like a sufficiently diversified group for the purposes of this initiative.