

1. *Should the Commission be selecting projects in the RFP process using additional criteria besides price? For example, should the Commission develop a method for adjusting bid prices to reflect the costs or benefits associated with interconnecting a distributed energy resource at a particular location on the grid?*

Whatever structure is adopted it should be straightforward (minimizing administrative costs) with a fixed price per block. Incentives and disincentives could be provided like the Massachusetts program in order to encourage/discourage development of certain types of sites, and in certain areas of the grid if it is constrained. However, it seems to us as if the recent focus on location of projects on the grid is overblown. As a practical matter if the grid is constrained in a certain area, the interconnection costs required to interconnect the new generator would be prohibitive, thus naturally taking care of the issue of more facilities in a particular area.

In any case, additional gating items for participation, such as exist in the Massachusetts program, would increase the success of the program. Those requirements create a self-selecting process where the marginal projects fall by the wayside before they enter the program.

Allco has previously suggested considering an express lane in addition to the regular lane under an RFP. The Express Lane would be similar to the Massachusetts program with significant gating items to participate. For example, under the Express Lane projects that would commit to a 12-month in-service date from execution of a PPA (with no extension except, like in Massachusetts, if the project is mechanically complete but the utility has not completed the interconnection) would have their own fixed block allocation. A high non-refundable development security deposit could be required. Projects that entered into that block would have of necessity been far along on development and probably near obtaining a CPG, or have obtained a CPG. The plus side is that those projects would, except in the most unusual circumstance, get built, and the health, climate, energy and load reducer benefits would commence in the near term. The Express Lane concept has worked exceptionally well in Massachusetts with the SREC program and has been carried over to the new SMART program.

Creating an Express Lane also maximizes the opportunity for use of the 30% federal tax credit. Any project selected under the usual RFP parameters in 2018 would not be in service until 2020 at the earliest. The federal tax credit drops to 26% in 2020, 22% in 2021, and 10% for 2022 and thereafter.

In any case, if the Commission retains the current bid format, the bar should be raised for participation. The current format creates essentially a free option for bidders. As both the 2016 and 2017 solicitations show, some of the selected bidders simply have not done sufficient due diligence before submitting bids.

2. *What data should the Vermont distribution utilities be making available to ensure that standard-offer projects are proposed in areas that do not result in additional costs to the system or that provide the greatest benefit to the system?*

Transparency is key. The interconnection queue should be public and so should system impact and facilities studies. That would enable developers to make a better determination as to

where projects should be located. The GMP Solar map is a great start, and with disclosure of prior studies to go along, its usefulness would increase and steer projects to the right areas.

3. *Should the Commission alter its process for identifying projects that would offer “sufficient benefits” pursuant to Section 8005a(d)(2)? For example, should the Commission develop a method for determining the value of a proposed distributed energy resource and offer contracts where the estimated value of benefits offered by a project exceeds the cost of the project? The Benefit Cost Analysis Framework adopted by the New York Public Service Commission is one example of a method to value the costs and benefits of distributed energy resources.*

The answer here is yes and yes. Allco has previously commented on this topic. Section 8005a(d)(2) describes what must be shown for a plant to receive a standard offer contract outside the cap. The plants must have “sufficient benefits to the operation and management of the electric grid or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit.”¹ (emphasis added.) In 2013 the Department of Public Service correctly described this provision as implementing a standard avoided costs analysis. The plain language of the statute and its legislative history show that the Department’s 2013 interpretation was the correct one. If the forecasted avoided costs from a project equal or exceed the price proposed by the generator then the Commission should consider that project to have “sufficient benefits to the operation and management of the electric grid,” and issue a contract.

4. *Should the Commission develop criteria to allow distributed generation projects with storage capacity to participate in the standard-offer program?*

Yes. Storage as part of a renewable energy project provides significant additional benefits to ratepayers, which GMP has quantified in its recent filings regarding storage as an addition to its solar projects. The standard offer statute contains no restriction on creating a separate technology allocation for a solar project with storage. Solar or wind with storage attached allows for the energy to be injected into the grid at the most useful times. There is no reason to continue to delay incorporating storage into the standard offer program.

5. *In certain circumstances, the program incurs transmission service costs (also referred to as “wheeling”) because the output of standard-offer projects must be allocated to several of the Vermont electric distribution utilities. Should the Commission adopt program requirements to reduce the cost of transmission service associated with standard-offer projects?*

The requirement that a portion of the energy from standard offer contracts be wheeled from the interconnecting utility to other utilities is a waste of ratepayer funds and creates needless administrative complexity and issues under federal law. It is a waste of ratepayer funds because (i) whatever is wheeled outside of the interconnecting utility is no longer a “load reducer” for that utility, and (ii) it adds costs for transmission that are needlessly incurred.

¹ 30 V.S.A. §8002 (23) "Vermont composite electric utility system" means the combined generation, transmission, and distribution resources along with the combined retail load requirements of the Vermont retail electricity providers.

Instead of all the added complexity and increased costs, the utilities should just have a periodic catch-up transfer payment among themselves that would account for any imbalances.

In any case, the utilities should handle all administrative aspects including executing any applications for transmission that might be needed. Burdening generators with becoming participants in ISO-NE for purposes for wheeling might be appropriate for 20MW-plus projects but not for the small projects in the standard offer. And if the utilities do not want to sign transmission service requests that fact alone should alert the Commission that something is not right with laying off that responsibility on small generators. The utilities are the most knowledgeable regarding the circumstances and costs of which they complain. They should work it out among themselves and make compensating payments approved by the Commission rather than adding even more administrative complexity to a process that has other challenges.

6. *Are there any statutory changes that the Commission should recommend to the Legislature to improve the standard-offer program? For example, what recommendations should the Commission make regarding the ability of distribution utilities to seek exemptions from the program pursuant to 30 V.S.A. § 8005a(k)(2)(B)?*

Yes.

- a. The cap on project size should be raised to 5MWs. 5MWs is becoming a standard size for GMP-owned solar plants. 5MW is the cap for “load reducer” treatment in ISO-NE. And 30 V.S.A. 8005 now has a separate category for projects or 5MWs or less, defining those projects as “distributed renewable generation.”
- b. The annual and overall caps should be greatly increased.
- c. The provider block should be eliminated. Providers have the ability to propose projects in their own territory, as GMP has done, and seek rate recovery.
- d. Permitting should be streamlined. The same issues should not have to be litigated in every section 248 docket. The current permitting system raises costs for projects, and delays their in-service. A hard look should be taken as to whether the current regulation is in the best long-term interests of Vermont.

7. *Other issues that the Commission should consider in its review of the standard-offer program.*

Health and Climate Costs. Fossil fuel generation not only is destroying the planet, but is responsible for the pre-mature death of countless Americans.² Recently the U.S.

² See, https://www.epa.gov/sites/production/files/2017-10/documents/ria_proposed-cpp-repeal_2017-10.pdf; https://www.washingtonpost.com/news/energy-environment/wp/2017/11/01/trumps-epa-says-obamas-climate-rule-could-prevent-up-to-4500-deaths-annually-moves-to-scrap-it/?utm_term=.f0597f004dfa.

Administration released a dire report on the prospects for the climate. See <https://science2017.globalchange.gov/chapter/executive-summary/>. USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment, Volume I* [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: [10.7930/J0J964J6](https://doi.org/10.7930/J0J964J6). The report concludes that “[s]ea level rise will be higher than the global average on the East and Gulf Coasts of the United States.” *Id.* Stronger storms will be more frequent raising the costs to recover from such storms. The east coast, including the Northeast, in particular will see more frequent and stronger storms and hurricanes. *Id.* at Chapter 9. <https://science2017.globalchange.gov/chapter/9/>. See also, *id.* at Fig. 9.2.

In any program re-design the Commission should consider that a fixed feed-in tariff like the standard offer program could be, has the potential to provide the highest benefit to ratepayers. With the requirement that pricing is no greater than avoided costs, the standard offer pricing is neutral to positive for Vermont ratepayers while providing the societal benefits of displacement of fossil fuels and CO₂. Other programs, such as Vermont’s recent significant increase in net-metering, is a net negative for ratepayers (except for those that participate in net-metering). Reduced retail sales of regulated utilities results in the utilities recovering their costs against an ever decreasing retail base, raising costs for those that remain.

Compatibility with PURPA. The recent group of Allco-related PURPA cases³, particularly the *Winding Creek* case, casts a long shadow over the current rule 4.100 program (particularly the 7-year cap on the term, and the variable capacity payments). Vermont’s rule 4.100 and standard-offer program have many parallels to California’s standard contract and Re-MAT program. Both the Vermont standard offer and California’s Re-MAT are the only programs under which generators can finance their projects because of the fixed rates and the length of the term. Both, however, have caps and both use an auction (or bidding) mechanism to adjust the price. Both also were mentioned in declaratory orders from FERC as being in some type of permitted alternate status under PURPA. The district court for the Northern District of California recently held caps and the use of a bidding mechanism were invalid, and that the term over which the forecasted rate must be determined is based upon the term offered by the generator. *Id.* at 13 (“it is also undisputed that PURPA and the implementing FERC regulations contain a ‘must-take obligation’ -- a mandatory purchase obligation on the part of utilities to buy ‘any energy and capacity which is made available from a qualifying facility’ -- which remains in place for facilities like the [plaintiff’s] facility. [] The plain meaning of this requirement is that utilities must buy all of the energy and capacity offered by QFs.”) It does not “require significant legal analysis to conclude” that a cap imposed upon the number of years a qualifying facility can offer its energy and capacity “violates the must-take obligation.” See *id.* at 13.

Use of the “sufficient benefits” provision to award contracts based upon a “value of solar” avoided costs analysis would fully satisfy PURPA, and should be what the standard offer redesign is based on.

³ *Winding Creek LLC v. Peevey*, No. 3:13-cv-04934-JD, 2017 U.S. Dist. LEXIS 201893, 47 ELR 20163, 2017 WL 6040012 (N.D. Cal. December 6, 2017) (“*Winding Creek*”); *Windham Solar LLC*, 157 FERC ¶ 61,134 (2016); and *Allco Renewable Energy Ltd. v. MA Elec. Co.*, 208 F. Supp. 3d 390 (D. Mass. 2016) *aff’d* 875 F.3d 64 (1st Cir. 2017).

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