BURLINGTON
ELECTRIC
DEPARTMENT

February 2, 2018

Judith Whitney, Clerk
Vermont Public Utility Commission
112 State Street, Montpelier, VT

Re: Case 17-5257-INV – Review of the standard-offer program

Dear Ms. Whitney:

In a memo dated December 29, 2017, the Public Utilities Commission ("PUC") requested responses to a series of questions related to Vermont's Standard Offer Program. Vermont Public Power Supply Authority ("VPPSA") and Burlington Electric Department ("BED") offer the following comments in response to the PUC memo. In general, VPPSA and BED believe that relatively minor modifications can be made to further promote the stated goals of the Standard Offer Program without subjecting ratepayers to unnecessary costs or undue levels of risk.

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?

More than 62 MW of renewable energy project capacity has been commissioned under the Standard Offer Program since 2009[1]. The implementation of an RFP process in 2013 improved the Program by providing to ratepayers the value of the products associated with Standard Offer generation at prices that were much lower than the original program (but still above market equivalent). Since the move to the RFP market mechanism, it has become even more clear that the value of additional Standard Offer generation varies based on its location.

The Standard Offer Program was established to achieve the goals articulated in 30 V.S.A. § 8001, which include "Providing support and incentives to locate renewable energy plants of small and moderate size in a manner that is *distributed across the State's electric grid*, including locating such plants in areas that will provide benefit to the operation and management of that grid through such means as reducing line losses and addressing transmission and distribution constraints."[2] (emphasis added.)

However, to date, Standard Offer deployment has occurred disproportionately in certain areas of the State. In some instances, this development is putting increased pressure on economically constrained areas of the transmission and distribution grid. This development pattern limits the value that ultimately flows to ratepayers

[1] http://www.vermontstandardoffer.com/standard-offer-program-summary/
[2] 30 V.S.A. § 8001 (a)(7)

from the Standard Offer Program and other renewable energy development in the State. For Standard Offer projects proposed within the Sheffield Highgate Export Interface ("SHEI"), for example, additional Standard Offer generation would result in a corresponding reduction in generation from existing renewable plants within that region; in this example, the overall benefits of the Standard Offer generation's "renewability" is reduced. While developers appropriately bear the costs of interconnection upgrades, and these costs are thus included in Standard Offer bids, these bids do not reflect the ratepayer costs due to increased curtailments once a Standard Offer project is interconnected.

Thus, to maximize the benefits of the Standard Offer program, the PUC should implement an RFP selection process that considers the location of proposed Standard Offer projects. In our view, not all potential Standard Offer projects are created equal. VPPSA and BED suggest assigning a sliding scale of price adjustments to different areas of the State. Such an assignment would provide market participants appropriate economic signals as to where distributed generation would produce the greatest value to the State. Vermont Electric Power Company ("VELCO"), the State's transmission grid operator, could conduct a statewide analysis of grid capacity and determine where additional Standard Offer generation would not lead to or exacerbate grid constraints. The result would be a publicly available map indicating where new Standard Offer generation was more or less desirable, from a grid perspective.

This analysis would be similar to work done by VELCO in 2012 to study non-transmission alternatives to the Central Vermont constraint identified by ISO New England. The result of that analysis was the identification of zones within the State where additional generation would alleviate or exacerbate that constraint. Different "location effectiveness factors" were then applied to the zones to differentiate the value of generation placed in various parts of the State. A similar methodology should be applied to the Standard Offer RFP process.

In unconstrained areas, renewable generation proposed by a potential Standard Offer plant could be granted by the Commission a rebuttal presumption that its connection to the grid would not materially impact reliability or affect the public good of the State. These projects would be evaluated strictly on their bid price. For constrained areas, it would be assumed that additional generation would either necessitate grid upgrades or lead to the curtailment of existing generators in that region; for projects proposed in constrained areas, bid prices would be adjusted upwards to reflect the adverse economic impacts on the State of generating additional electricity in a constrained area. For example, if a proposed project in an unconstrained area bid into the RFP at a price of $0.11/kWh, it would be considered based on this price. If another project proposed in a constrained area bid at $0.10/kWh an adjustment factor reflecting the grid constraint (1.2 for illustrative purposes) would be applied, and that project would be evaluated based on a bid price of $0.12/kWh ($0.10 X 1.2) to reflect the higher economic costs of locating projects in constrained areas of the State. While the bid would be evaluated and ranked by the PUC using the $0.12 price, if that project were selected by the PUC to be awarded a Standard Offer Contract, it would continue to be paid the $0.10 offer. Adjusting bid prices upwards for evaluation of projects proposed in constrained areas is a straightforward and transparent method for encouraging Standard Offer development in locations that will be most beneficial to the grid and Vermont ratepayers.

Finally, VPPSA and BED support the recommendation filed by VEPP Inc. in its comments in Case No. 17-3935-INV filed on October 20, 2017 related to establishing and interconnection requirement for Standard Offer proposals.

VEPP Inc. suggested that each applicant be required to include a letter from the interconnecting utility identifying any utility concerns along with the Standard Offer bid proposal. VPPSA and BED believe this would be a useful requirement that would help ensure interconnection issues are identified and addressed early in the process.

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?

Vermont's distribution utilities ("DUs") should assist VELCO by providing needed distribution-level data to VELCO to complete the analysis described above. As operator of the Vermont transmission system (generally equipment operating at 115 kv and above) VELCO bears the responsibility for operating, maintaining, and planning for the future of the Vermont transmission grid. Distribution utilities regularly provide data to VELCO for purposes such as the preparation of Long-range Transmission Plan. To the extent VELCO needs additional data on the distribution system, DUs should provide it and work collaboratively with VELCO to complete the analysis.

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 PUC's question touches on two distinct concepts: the "sufficient benefits" test and valuation methodology. Under 30 V.S.A. § 8005a(d)(2) projects that meet the criteria for providing "sufficient benefits" do not count towards the established 127.5 MW program cap.

VPPSA and BED do not recommend revisiting the "sufficient benefits" framework laid out in the PUC's March 1, 2013 *Order re: Establishment of Standard-Offer Prices and Programmatic Changes to the Standard Offer Program*. The "sufficient benefits" language in Section 8005a(d)(2) and the subsequent screening framework were adopted at a time when there were several areas of the grid that had been identified as being constrained from a load perspective (as opposed to constrained from the perspective of too much generation). Siting additional distributed generation resources was one method for potentially alleviating these constraints and there is no reason to believe the framework that has been established wouldn't achieve that goal if additional, load-constrained areas emerged. Currently, conditions on the transmission and distribution grid have changed such that the State is experiencing flat or declining loads and increases in generating capacity. Moreover, there is some concern being expressed that present load conditions, coupled with continued expansion of distributed generation may actually increase losses on the system. Should we re-enter a period of load growth, as is widely expected with electrification of the heating and transportation sectors, the established "sufficient benefits" framework would probably prove effective in locating Standard Offer generation in areas that alleviate grid constraints.

Implementing a valuation methodology, such as the Benefit Cost Analysis Framework adopted by New York, would likely not be beneficial to ratepayers. Vermont's collective experience conducting valuation and avoided cost calculations under Rule 4.100, the Standard Offer Program, and in net metering proceedings has established that engaging in these efforts is time-consuming and complex, and the resulting values are imprecise. Importantly, the risk of the projected value not materializing is placed on ratepayers; in many instances ratepayers have been burdened with the ongoing costs of long-term contracts that end up being drastically above market prices. The current RFP mechanism appropriately balances the needs of developers, by providing long-term contracts at prices above market, while allowing ratepayers to secure the benefits of these contracts through a competitive mechanism that ties prices to the cost to develop a resource rather than its projected value.

In the case of the Benefit Cost Analysis Framework in New York, valuation of solar has indeed proven to be a contentious, multi-year process, with resulting values that are updated annually. For the Vermont Standard Offer Program, which is expected to have its last solicitation in 2022, such a lengthy, complex endeavor would not be a wise use of stakeholder resources.

Finally, the value of small-scale, distributed resources is already accounted for in the design of the Standard Offer Program in that Vermont has committed to securing a defined amount of these resources even if such resources are acquired at above-market costs. The capacity cap on the Standard Offer Program was adopted to limit the costs ratepayers would be required to incur. Within that statutory cap, the most cost-effective resources should be selected without attempting to assign additional value that is already recognized under the program construct and long-term contracts. The current RFP process, with the modifications as proposed by VPPSA and BED to price evaluation for known constrained areas of the grid, successfully achieves this outcome.

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

The Standard Offer Program was designed to increase the amount of renewable energy *generating capacity* located within the State. Storage, in and of itself, does not constitute generating capacity and does not meet the definition of "new standard offer plant" in 30 V.S.A. § 8005a (b). Storage differs significantly from generation resources in that it both draws energy from the grid (or directly from a generator) and delivers energy onto the grid and results in a net reduction in system energy due to losses inherent in the storage system. In other words, storage is a consumer of energy, not a producer of renewable energy.

It is VPPSA and BED's understanding that renewable energy plants that are connected to storage facilities would be eligible to participate in the Standard Offer Program, and no programmatic changes are necessary to allow this participation. These plants would be compensated based on kWh production just as other Standard Offer resources are. A plant owner could then make operational decisions about how to deploy the storage resource and when to deliver power to the grid. The plant owner could potentially capture other value streams, such as frequency regulation or peak shaving, but Vermont ratepayers would only be responsible for purchasing the energy, capacity, and renewable energy certificates from the generator under the Standard Offer Program.

Some stakeholders have suggested that Standard Offer plants that utilize storage could be compensated at a higher rate than other Standard Offer plants because of the potential added value they may provide. As detailed in the Public Service Department's recent *Act 53 Report: A Report to the Vermont General Assembly on the Issue of Deploying Storage on the Vermont Electric Transmission and Distribution System,* the value of storage resources is extremely dependent on the location of the resource, who is deploying the storage resource, and how the storage will operate. Thus, requiring ratepayers to pay a premium for Standard Offer plants that utilize storage capability, whether or not they bring ratepayer benefit from the storage operation, is not appropriate. In order to accurately understand the potential value of a storage resource, there would need to be an assessment of the location, capacity size, energy size, technology type, interconnection design, and who would ultimately control decisions about battery charge and discharge. This would add a considerable administrative burden into the Program which would likely not be offset by any potential value to ratepayers, especially considering the Standard Offer Program expires in 2022. Vermont's utilities are already deploying storage outside of the Standard Offer program, and they will continue to do so in instances where the expected value delivered to ratepayers exceeds the costs.

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?

With Washington Electric Coop, BED, and Swanton Electric exempt from the Program, the remaining VPPSA utilities incur significant wheeling costs in addition to the energy costs allocated through the Standard Offer Program. To the extent that wheeling revenue collected from a host utility is used to help cover that utility's sunk costs and reduce the amount of transmission revenue collected from the host utility's ratepayers, wheeling charges can be considered a transfer payment from one utility's customers to another utility's customers.

However, the rationale for allowing utilities to charge wheeling for Standard Offer generation above each utility's pro rata share of the generation is that utilities incur actual costs for wheeling this power. The wheeling revenue charged by distribution utilities for transmitting Standard Offer generation should, theoretically, be used to maintain and upgrade the system over which that generation is wheeled. Theoretically, a host utility is justified in charging wheeling costs for Standard Offer projects because these projects create added costs to the transmission and distribution system. Thus, wheeling revenue should be used to upgrade the transmission and distribution system to accommodate the increased flow of electricity in areas where Standard Offer plants are located. The extent to which this is happening in areas such as the SHEI is unclear; in that area of the State, the utilities that are collecting the wheeling payments (in return for providing market access to Standard Offer generators) are the ones experiencing the largest financial impacts from the export limits within the SHEI. The PUC should ensure that, to the extent transmission costs are collected, those payments are used to provide the envisioned market access.

VPPSA and BED have previously recommended including indicative "wheeling costs" in Standard Offer bids so that projects with the lowest *overall* costs would be selected in the RFP. At this point, we are not recommending that these changes be incorporated into the RFP because the changes described in response to

question #1 above should help alleviate the disproportionate concentration of Standard Offer plants within certain utilities' service territories.

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)?

VPPSA and BED believe that the exemption described in 30 V.S.A. § 8005a(k)(2)(B) is being used in a manner consistent with the legislative intent and should continue to be allowed for those utilities currently taking advantage of that exemption. The Legislature was aware that additional exemptions could occur when it enacted this provision and nevertheless chose to include it to avoid disincentives for utilities to pursue renewable energy contracts on their own. Utilities that have secured renewable resources equivalent to 100% of their retail sales should not be required to purchase renewable power through the Standard Offer Program that would make them have excess supply.

BED and VPPSA do recognize that if more and more utilities become exempt from the purchase requirement, costs of the Standard Offer Program will further shift onto the ratepayers of utilities that remain participants in the Program. However, it is not known whether this cost shifting is actually an economic harm to a utility that has not contracted for 100% renewable resources (that are typically more expensive than non-renewable alternatives). For example, it is not clear that the average cost of energy purchased by non-exempt utilities (even with the increased Standard Offer assignment included) results in a materially higher overall average cost of energy purchase for non-exempt utilities as compared with those that are exempt from Standard Offer purchases. Thus, there may be little incentive for utilities that do not already have renewable resources equivalent to 100% of their retail sales in their power supply portfolios to pursue additional contracts solely to become exempt from Standard Offer purchases.

In our view, exemptions should be tied to not only to receiving 100% renewable energy in a single year, but also to a demonstration by the utility that it is committed to a 100% renewable supply path. Rather than removing the exemption possibility, VPPSA and BED believe that further clarity around the requirements necessary for additional utilities to achieve the exemption in a way that demonstrated commitment to maintaining the 100% renewable criteria would be beneficial.

Thank you for your consideration of these comments.

Sincerely,

Melissa Bailey
Legislative and Regulatory Affairs Representative
Vermont Public Power Supply Authority