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State of Vermont
Public Utility Commission

February 20, 2018

TO ALL PARTIES IN PUC CASE NO. 17-3935-INV

RE: Investigation into programmatic adjustments to the standard-offer program for 2018

Dear Parties:

Pursuant to 30 V.S.A. Section 8 and 3 V.S.A. Section 811, I am enclosing my Proposal for Decision in the above case.

If you have any comments, please file them on or before Monday, March 5, 2018. Any comments will then be submitted to the Vermont Public Utility Commission ("Commission") along with the Proposal for Decision for final determination. If you wish, you may request oral argument before the Commission. Any request for oral argument must be filed with the Commission by March 5, 2018.

It should be emphasized that the enclosed Proposal is not a final decision of the Commission and may be subject to modification by the Commission.

Very truly yours,

Mary Jo Krolewski

Mary Jo Krolewski
Hearing Officer

Enclosure

PUC Case No. 17-3935-INV - SERVICE LIST

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STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 17-3935-INV

Investigation into programmatic adjustments to the standard-offer program for 2018	

Order entered: 02/20/2018

2018 PROGRAMMATIC ADJUSTMENTS TO THE STANDARD-OFFER PROGRAM

I. INTRODUCTION

Established in 2009, pursuant to 30 V.S.A. § 8005a, the standard-offer program promotes the rapid deployment of small renewable generation. The Vermont Public Utility Commission ("Commission") has implemented the program through previous Orders in Dockets 7523, 7533, 7780, 7873, 7874, and 8817.

Under the program, Vermont distribution utilities are required to buy renewable power from an eligible generator at a specified price for a specified period of time. Program costs are distributed among Vermont utilities based on their *pro-rata* share of electric sales. The program is administered by a statewide purchasing agent ("Standard Offer Facilitator") appointed by the Commission.[1]

The standard-offer program was created with a 50 MW initial program capacity that was expanded to 127.5 MW in 2012. Eligible projects can be no larger than 2.2 MW in size and include the following technologies: solar; wind with a capacity of 100 kW or smaller ("small wind"); wind with a capacity greater than 100 kW up to 2.2 MW ("large wind"); farm methane; landfill methane; food waste anaerobic digestion; biomass; and hydroelectric. Eligible projects selected through a lottery received a standard-offer contract and the contract price was based on technology-specific avoided costs.

In 2012, statutory changes were made to the program that included an increase in the available program capacity to 127.5 MW, distributed annually as follows: 5 MW in 2013-2015; 7.5 MW in 2016-2018; and 10 MW available in 2019-2022. A specific portion of each year's capacity is reserved for projects proposed by Vermont utilities and is referred to as the Provider Block, with the remainder referred to as the Developer Block. The 2012 changes also: (a)

[1] VEPP Inc. ("VEPP") serves as the Standard Offer Facilitator under contract to the Commission.

require allocation of available capacity among different technology categories; (b) allow market-based pricing methodology; and (c) require review of avoided-cost prices every year.

Since 2013, the Commission has issued an annual request for proposals ("RFP") to fill the available annual capacity under the program. Issued by the Standard Offer Facilitator, the annual RFP specifies annual program capacity, technology allocations, and avoided-cost price caps.[2] Under the RFP, lowest-priced bids are awarded annual capacity. Farm methane projects remain outside the program cap (i.e., no restrictions on the number of projects that can participate in the program) and therefore do not have to participate in the annual RFP.

In this proposal for decision, I make several recommendations with regard to the implementation of the 2018 standard-offer program, including the allocation of available capacity under the program and the technology-specific avoided costs that will serve as price caps in the 2018 RFP.

II. Procedural History

In 2017, the Commission established a mechanism for the allocation of available standard-offer program capacity pursuant to Section 8005a(c)(2), and determined the technology-specific avoided costs that served as price caps on the standard-offer projects solicited through the 2017 RFP pursuant to Section 8005a(f)(3).[3] In addition, the Commission determined the avoided costs that served as the prices for farm methane projects under the standard-offer program.[4]

On August 22, 2017, the Commission opened an investigation into programmatic adjustments to the standard-offer program that included a review of the technology allocation and the price caps applicable to standard-offer projects solicited through the 2018 RFP.[5]

On October 20, 2017, comments were filed by the Vermont Department of Public Service ("Department"), the Vermont Agency of Natural Resources ("ANR"), Vermont Agency of Agriculture, Food & Markets ("AAFM"), Ag-Grid Energy LLC ("Ag-Grid"), Allco Renewable

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[2] The Standard Offer Facilitator maintains a website for the program that includes the annual RFP and other information: http://www.vermontstandardoffer.com/.

[3] *Order Re 2017 Technology Allocation and Price Caps for the Standard-Offer Program*, Docket 8817, Order of 3/2/17; *Order Re Motions to Alter or Amend and Motions to Reconsider*, Docket 8817, Order of 3/29/17; *Order Re Second Motions to Alter or Amend*, Docket 8817; Order of 4/2/17.

[4] Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap.

[5] *Order Opening Investigation, Establishing Schedule, and Notice of Workshop*, Case 17-3935-INV, Order of 8/22/17.

Energy Limited ("Allco"), The Conti Group ("Conti"), Dynamic Organics, LLC ("Dynamic"), Green Mountain Power Corporation ("GMP"), Renewable Energy Vermont "REV"), Star Wind Turbines ("Star Wind"), Vermont Electric Cooperative, Inc. ("VEC"), and VEPP.

On November 7, 2017, I conducted a workshop to discuss the programmatic adjustments to the standard-offer program.

On November 20, 2017, reply comments were filed by the Department, ANR, AAFM, Allco, Dynamic, Fundamental Energy, LLC ("Fundamental"), GMP, Purpose Energy, Inc. ("Purpose"), REV, Star Wind, VEC, and VEPP. The City of Burlington Electric Department ("BED") and Vermont Public Power Supply Authority ("VPPSA") filed joint reply comments.

On December 5, 2016, REV filed additional comments.

No other comments have been received.

This proceeding has not used contested-case procedures, and all interested persons have been afforded the opportunity to participate through a workshop and written filings. Because this process was not a formal case, there were no parties and no deadlines for intervention. In this proposal for decision, I use the term "participants" to refer to the individuals and entities who participated in some manner in this process.

III. TECHNOLOGY CATEGORIES AND ELIGIBILITY

Pursuant to Section 8005a(b), new renewable energy plants located in Vermont that have a nameplate capacity of 2.2 MW or less are eligible to participate in the standard-offer program. Pursuant to Section 8005a(c)(2), the Commission must allocate the 127.5 MW cumulative program capacity among different categories of renewable energy technologies. These categories must include at least the following: solar; small wind; large wind; landfill methane; biomass; and hydroelectric.

Pursuant to 30 V.S.A. § 8002(21)(A), renewable energy includes energy produced through the anaerobic digestion of food wastes. In 2015, the Commission added food waste anaerobic digestion as a technology category under the standard-offer program.[6]

The standard-offer program also includes farm methane projects. Pursuant to Section 8005a(g), farm methane projects remain outside the 127.5 MW program cap, and thus do not

[6] *Order Re 2015 Technology Allocation*, Dockets 7873 and 7874; Order of 2/17/15.

participate in the annual RFP. Farm projects can receive a 20-year contract at any time by contacting the Standard Offer Facilitator.

A. Food Waste Anaerobic Digestion Eligibility

Food waste anaerobic digestion projects and farm methane projects are similar technologies. Both technologies employ an anaerobic digester that produces methane that then fuels an engine-generator set to produce electricity. However, these projects differ with regard to primary feedstock and participation in the standard-offer program. Feedstocks for food waste anaerobic digestion projects must be derived from food residuals. Feedstocks for farm methane projects must be derived from farm operations and typically include manure. Unlike farm methane project, food waste anaerobic digestion projects are included in the 127.5 MW program cap and must participate in the annual RFP to be eligible for a standard-offer contract. As discussed further below, the Commission establishes separate prices for these technology categories.

When food waste anaerobic digestion was added as a technology category, the Commission did not specify whether the feedstocks for these projects had to be primarily or entirely derived from food residuals. This lack of specificity has led to some confusion among program participants as to what type of projects may qualify for the category. Therefore, further clarity is needed on the type and amount of feedstocks that qualify projects for this category.

Participants' Comments

ANR recommends that the Commission define a food waste anaerobic digestion plant as a facility that is fueled greater than 50% by volume from food residuals as defined in 10 V.S.A. § 6602(31). ANR suggests that volume can be determined on a monthly basis. ANR states that food residual is an overarching umbrella term for pre- and post-consumer food scraps, and includes processing residuals that are the remaining organic material from a food processing plant. ANR represents that processing residuals may include whey and other dairy, cheese-making, and ice cream residuals, or residuals from any food manufacturing process excluding slaughtering and rendering operations.

ANR states that operators of food waste anaerobic digesters often introduce non-food residual into the fuel mix to maximize output and maintain consistent operation of the facility. ANR recommends that food waste anaerobic digesters also be permitted to use a minority by volume of non-food residual fuel. ANR represents that typical non-food residual fuels include animal manure, fats, oils, greases, glycerol, and to a lesser degree, biosolids from waste treatment facilities. ANR states that typically these fuels can be considered renewable as they are waste products of another, unrelated activity.

GMP supports defining a food waste anaerobic digestion plant as a facility that is fueled greater than 50% by volume from food residuals, mass input on an annual basis. GMP argues that this determination is supported by statute and previous Commission precedent. GMP contends that the definition of renewable energy under Section 8002(21)(A) includes "anaerobic digestion of agricultural products, byproducts, or wastes, or of food wastes," but does not require a particular percentage of food waste be used as feedstock to qualify as renewable. GMP further maintains that the greater than 50% by volume definition is supported by previous Commission determinations requiring 51% of the feedstock for farm methane projects to be derived from farm operations.

Dynamic, Purpose, and REV also support defining a food waste anaerobic digestion plant as a facility that is fueled greater than 50% by volume from food residuals, mass input on an annual basis. However, Dynamic and Purpose contend that fats, oils, and greases derived from plant or animal based materials should also be defined as food residuals.

<u>Discussion</u>

As the participants have advocated, I recommend that the Commission define a food waste anaerobic digestion plant as a facility that is fueled greater than 50% by volume from food residuals as defined in 10 V.S.A. § 6602(31). In addition, I recommend that the 50% by volume be determined by mass input on an annual basis. This recommendation is consistent with the Commission's determination for the farm methane category that required that 51% by volume of the feedstock (mass input on an annual basis) be derived from farm operations.[7] In addition, this recommendation recognizes that the practice of using feedstocks not derived from food residuals provides significant benefits and that to entirely exclude the use of such feedstocks would limit the flexibility of food waste anaerobic digestion projects.

Pursuant to 10 V.S.A. § 6602(31), food residual means:

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[7] *Second Order Re Implementation Issues*, Docket 7533, Order of 10/28/09; *Order Re: Farm Methane Project Eligibility*, Docket 7533, Order of 3/28/11.

> source separated and uncontaminated material that is derived from processing or discarding of food and that is recyclable, in a manner consistent with section 6605k of this title. Food residual may include pre-consumer and post-consumer food scraps. "Food residual" does not mean meat and meat-related products when the food residuals are composted by a resident on site.

ANR states that processing residuals may include whey and other dairy, cheese making, and ice cream residuals, or residuals from any food manufacturing process excluding slaughtering and rendering operations, and states that typical non-food residual feedstocks include animal manure, fats, oils, greases, glycerol, and to a lesser degree, biosolids from waste treatment facilities. Dynamic and Purpose contend that fats, oils, and greases derived from plant or animal based materials should be defined as food residuals. I recommend that the Commission accept ANR's position that fats, oils, and greases are non-food residual feedstocks.

B. Storage

Pursuant to Section 8005a(b), in order to be eligible for a standard-offer contract, a plant must be a "renewable energy plant." Pursuant to Section 8002(21), renewable energy means "energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate." Further, pursuant to Section 8002(21)(D), "the Commission by rule may add technologies or technology categories to the definition of 'renewable energy'."

Participants' Comments

The Department recommends that storage not be incorporated into the 2018 RFP, either as a technology category unto itself, or as a combined feature of existing technology categories. The Department contends that storage provides no value by itself, but provides value only when the charge and discharge of the resource is timed to provide grid benefits. The Department maintains that storage should not be incorporated into the standard-offer program until the following can be addressed: who is responsible for operating the resource; what value streams are being pursued through a solicitation; how to identify optimal locations for storage; and how individual storage resources will provide benefits to ratepayers.

Allco supports the establishment of a separate technology category for renewable facilities that add storage. Allco further argues that the standard-offer statute contains no restriction on creating a separate technology allocation for a renewable energy project with storage. In order to establish a price cap for the category, Allco suggests the Commission consider adopting the fixed price adder methodology used under the Solar Massachusetts Renewable Target Program or using the calculated benefits for storage projects recently implemented by GMP. Allco argues that storage would bring substantial benefits to the Vermont electric grid because it allows for the energy to be injected into the grid at the most useful times.

REV supports the establishment of a separate technology category for renewable facilities that include storage or new energy storage projects added to existing renewable energy generation. REV maintains that renewable energy storage can provide multiple benefits to Vermont customers by reducing the cost of electricity supply and the distribution system while improving reliability. REV further maintains that the addition of storage is consistent with the *2016 Vermont Comprehensive Energy Plan*'s recommendations to encourage the deployment of energy storage. REV recommends that if the Commission does not allow for energy storage projects in the 2018 standard-offer program that a process be provided so that such projects may participate in the 2019 program.

GMP does not believe it is appropriate to expand the scope of the current proceeding in order to consider the complex and significant issues related to the potential role of battery storage in renewable development and grid management. BED, VPPSA, and VEC argue that the standard-offer program is not the appropriate venue for encouraging storage development and that the value of storage resources varies widely based on location and how storage devices are deployed. VEC maintains that there is not statutory authority to expand the standard-offer program to storage resources. VEC further maintains that allowing the location of storage to be subject to an RFP mechanism and/or allowing the time of charging/discharging to be determined by the developer will likely result in an inefficient deployment of battery storage. BED and VPPSA contend that it would be extremely challenging to assign a value to storage resources, and it would be very difficult to ensure that ratepayers received benefits commensurate with the costs.

Discussion

I recommend that storage not be incorporated into the 2018 RFP, either as a technology category unto itself, or as a combined feature of existing technology categories. No participant addressed how storage meets the statutory definition of renewable energy under Section 8002(21), and thus would be eligible for a standard-offer contract under Section 8005a(b).

Further, while Section 8002(21)(D) allows the Commission by rule to add technologies or technology categories to the definition of renewable energy, no participant proposed the Commission begin such a process or addressed why storage is an appropriate category to consider under such a process.

Further, whether considering storage by itself, or in combination with an existing technology, it is unclear that the standard-offer program is the appropriate venue to address the complexities associated with storage. The value of storage resources varies widely based on location and how storage devices are deployed. Individual storage resources, deployed by individual operators, may not add value to statewide renewable development and grid management. Based on these complexities, it is difficult to ensure that ratepayers will receive benefits commensurate with the costs.

C. Solar Parking Canopy Projects

In 2016, Public Act 174 codified Section 8005a(c)(1)(D), which mandated changes to the standard-offer program requiring the Commission to establish a one-year pilot program for standard-offer projects located at "preferred locations." Pursuant to Section 8005a(c)(1)(D), under the pilot program, for one year commencing on January 1, 2017, one-sixth of the annual increase was allocated to projects located over parking lots or on parking lot canopies and one-sixth of the annual increase was allocated to standard-offer projects at other preferred locations.

Participants' Comments

Conti recommends that the Commission continue a set-aside for solar parking canopy projects. Conti maintains that applying a 1.4 multiplier to the solar price cap is a reasonable approach for establishing a price cap for this allocation. Conti contends that solar parking canopy projects made possible under the standard-offer program will encourage future net-metered projects.

Discussion

I recommend that the Commission not establish a separate technology category for solar parking canopy projects. Section 8005a(c)(1)(D) established a one-year pilot program for standard-offer projects located at preferred locations, including projects located over parking lots or on parking lot canopies. The statute does not provide a basis for the Commission to allocate capacity to projects at preferred sites. Further, the Commission has previously concluded that standard-offer prices should be based upon the assumption of efficiently sized and located generation to ensure that the price incentives are not excessive and thereby unnecessarily costly for ratepayers.[8] Conti has not provided a persuasive reason why the Commission should disaggregate the solar category with higher prices for some solar units.

IV. RFP Requirements and Program Implementation

On March 1, 2013, the Commission established, pursuant to Section 8005a(f)(1), an RFP mechanism to determine the standard-offer projects that will fill annual plant capacity available under the program, and directed the Standard Offer Facilitator, by April 1 of each year, to issue an RFP to solicit standard-offer projects to meet the requirements of Section 8005a(c).[9] The 2013 Order also established technology-specific avoided costs to serve as caps on the standard-offer prices solicited through the RFP.

Since the first RFP was issued in 2013, twenty-seven projects have been awarded standard-offer contracts. Of the twenty-seven projects awarded contracts, three are commissioned and ten have withdrawn. More than half of the remaining projects have requested commissioning milestone extensions (eleven out of the remaining seventeen). Due to this success rate of standard-offer projects, many participants suggested changes to the RFP requirements and process. I address these suggestions below.

A. RFP Requirements

The annual RFP for the standard-offer program specifies the terms and conditions under which eligible projects are to develop proposals and the evaluation framework that the Standard Offer Facilitator will use to select projects that will be awarded standard-offer contracts. The annual RFP includes several requirements that a proposal must meet to be considered further under the RFP evaluation process. The requirements include the submittal of a project map, demonstration of site control, and demonstration that the proposed plant is an independent technical facility. The annual RFP does not contain interconnection application or study

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[8] *See* Docket 7533, Order of 1/15/10, Docket 7780, Order of 1/23/12, *Order Re 2016 Prices for Standard-Offer Program*, Docket 7874, Order of 3/7/16; and Docket 8817, Order of 3/2/17.

[9] *Order Re Establishment of Standard-Offer Prices and Programmatic Changes to the Standard-Offer Program*, Dockets 7873 and 7874, Order of 3/1/13.

requirements, but if the bid is a winning proposal, a complete interconnection application must be filed upon acceptance of a standard-offer contract.

<u>Participants' Comments</u>

VEPP recommends, based on its review of prevailing practices in other New England RFPs, several changes to the RFP requirements. Other participants made additional recommendations and responded to VEPP's recommendations. These comments are summarized by topic below.

Project Map

VEPP recommends that the requirement that proposals include a project map (Section 3.1 of the 2017 RFP) be expanded to include the following language:

> Proposals shall include a site plan including a map(s) that clearly identifies the property for which the proponent has site control including property line boundaries, the location of the project site on the property, any required rights-of-way, the total acreage of the project site, the anticipated interconnection point, the location of any existing projects or other proposed projects within a one-mile radius, and the relationship of the site to other local infrastructure, including power lines, roadways, and water sources. In addition to the project map, provide a site layout plan that illustrates the location of all major equipment and facilities such as panel arrays, inverters, transformers, and any required structures on the project site. The site layout plan should be provided on a 24″ x 36″ plan at a sufficient scale (i.e. 1 inch = 50 feet) such that the location of all project facilities are easily discerned.

VEPP maintains that requiring a more detailed project map will promote preliminary project development, identify parcel constraints, and assist proposal review. GMP states that the recommendation appears reasonable and increases the likelihood that projects receiving RFP awards will actually be developed.

Independent Technical Facility

VEPP recommends clarifying the section of the annual RFP that requires bidders to demonstrate that the proposed plant is an independent technical facility (Section 3.2.3 of the 2017 RFP). VEPP suggests adding language to mirror the statutory definition of a plant contained in 30 V.S.A. § 8002(18). VEPP contends that this addition will provide necessary information to complete review of proposals. GMP recommends that the RFP clarify that multiple projects with common ownership that are contiguous will be evaluated based on the total nameplate capacity of all abutting projects, not independently.

Site Control

Fundamental requests changes to the requirement that bidders must demonstrate site control (Section 3.2.2 of the 2017 RFP). Fundamental contends that the Commission should accept an easement or an option for easement as sufficient proof of site control.

Interconnection Requirements

VEPP also recommends that the annual RFP include a mandatory requirement that the bidder supply a letter from the interconnecting utility identifying any initial concerns the utility may have about the project's interconnection. GMP, while not objecting to this requirement, cautions that the type of informal consultation envisioned by VEPP may not provide meaningful insights as to the interconnection issues and associated costs that a particular project may face. Dynamic and Purpose did not support the addition of any mandatory requirements with regard to the project's interconnection.

Notice to Bidders

VEPP further recommends that the annual RFP provide notice to bidders that they will be required to submit a complete petition for a certificate of public good within one year of the effective date of the standard-offer contract. VEPP suggests including a link to its webpage on the standard-offer program that contains information on the certificate of public good process. VEPP represents that the goal of this recommendation is to minimize the occurrence of contract milestone extension requests and incomplete filings. GMP supports the additional notice.

<u>Discussion</u>

I recommend that the Commission accept VEPP's proposal with regard to the project map requirement. The requirement that proposals include a map is not overly burdensome, should assist proposal review, and promotes the likelihood that projects receiving RFP awards will actually be developed. In order to improve clarity of RFP requirements, I also recommend that this requirement be included under the mandatory requirements of the annual RFP.

I recommend that the Commission accept VEPP's recommendation to clarify the section of the annual RFP that requires bidders to demonstrate that the proposed plant is an independent technical facility by adding the statutory definition of a plant contained in 30 V.S.A. § 8002(18). The clarification of this mandatory requirement should assist proposal review and ensure that proposals contain the necessary information to complete review. To this requirement, I recommend that the annual RFP include the following language:

> **Independent Technical Facility**
>
> Pursuant to 30 V.S.A. § 8002(18), plants means "an independent technical facility that generates electricity from renewable energy. A group of facilities, such as wind turbines, shall be considered one plant if the group is part of the same project and uses common equipment and infrastructure such as roads, control facilities, and connections to the electric grid. Common ownership, contiguity in time of construction, and proximity of facilities to each other shall be relevant to determining whether a group of facilities is part of the same project."
>
> If a proposed project is located at, adjacent to, or near an existing or proposed renewable energy generation facility, the project proponent must demonstrate that the two facilities would be considered separate plants under 30 V.S.A. § 8002(18).

I recommend that the Commission reject Fundamental's request that the bidders be allowed to demonstrate site control with an easement or an option for easement. The site control requirement was implemented to "decrease speculative positioning in the queue by showing that the applicant has identified a particular location on which the project could be constructed…."[10] Fundamental has not explained why an easement demonstrates adequate site control and ensures that a project will be constructed at a particular location or can operate for the full term of the standard-offer contract. Specifically, easements do not generally convey exclusive possession of a site; a characteristic of the other types of site control accepted by the Commission.

I recommend that the Commission reject VEPP's proposal that the annual RFP include a mandatory requirement that the bidder supply a letter from the interconnecting utility identifying any initial concerns the utility may have about the project's interconnection. The requirement may be overly burdensome on bidders to secure and the interconnecting utilities to produce in advance of the RFP, while at the same time possibly not provide meaningful insights as to the interconnection issues and associated costs that a particular project may face.

Finally, I recommend that the Commission accept VEPP's proposal that the annual RFP provide notice to bidders that they will be required to submit a complete petition for a certificate of public good within one year of the effective date of the standard-offer contract and that the

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[10] *Second Order re Implementation Issues*, Docket 7533, Order of 10/8/09 at 2.

RFP include a link to VEPP's standard-offer program webpage that contains information on the certificate of public good process.[11] This notice will better inform bidders and promote project development.

B. RFP Award Group Requirements

Recipients of the standard-offer contract incur several obligations. First, within five business days of receiving notice of an award, the recipient is required to provide a non-refundable check for a $200 administrative fee and a separate check for the refundable deposit fee of $15 per kW.[12] Next, the recipient is required to file an interconnection application with the interconnecting utility within ten business days of award notification.

The standard-offer contract also states that projects are required to file a petition for a certificate of public good within one year of the contract signature date. Solar and small wind projects are required to be commissioned within two years of the contract signature date, and biomass, large wind, landfill gas, and hydroelectric plants are required to be commissioned within three years of that date.

If a project is commissioned within the applicable milestone date set forth in contract, 100% of the refundable deposit will be returned. For all technology categories, if a project voluntarily withdraws from the standard-offer program within the first year, the entire refundable deposit is returned. For small wind and solar projects, the deposit is refunded 50% if the project withdraws within the second year. For other project categories, the deposit is refunded 75% within the second year and 50% within the third year.

In addition to awarding contracts, the Commission establishes a reserve group comprised of no more than 4.5 MW of proposals with the lowest prices that were not awarded standard-offer contracts in the RFP. If a project withdraws from the RFP award group prior to January 1st of the subsequent year and the award group does not already exceed the annual capacity cap without that project, then a standard-offer contract is offered to the proposal within the reserve group that has the lowest price and that does not exceed the annual capacity cap by more than 2.2 MW. If a project withdraws from the award group after January 1st but before April 1st, then the capacity associated with that project is solicited in the next RFP.

[11] http://www.vermontstandardoffer.com/sop-contract-requirements/http://www.vermontstandardoffer.com/sop-contract-requirements/

[12] The RFP requires a proposal security of $10 per kW that is refunded to unsuccessful proposals and successful proposals that achieve commissioning.

Participants' Comments

VEPP has reviewed the prevailing practices in other New England renewable energy RFPs and recommends changes to the standard-offer contract with regards to the project security deposit. VEPP recommends that the $15 per kW deposit be fully forfeited when a project is withdrawn prior to commissioning, except if the petition for a certificate of public good is denied. VEPP maintains that this would increase the likelihood that RFP bids would be based on better planned, fully vetted projects, resulting in more standard-offer projects achieving commissioning.

The Department, Dynamic, and Purpose support this recommendation. The Department contends that the change should reduce speculative bidding and increase the likelihood of rapid deployment of resources. GMP suggests that the refunding of the deposit could be expanded to include those projects that diligently pursue Commission approval but ultimately withdraw the petition. Allco argues the refundable deposit should be non-refundable except under limited circumstances, such as force majeure.

Allco argues that the reserve group should be kept in place for a longer period. REV contends that the Commission should always maintain a reserve group of projects and should rapidly substitute projects from the reserve group for projects that do not meet standard-offer milestones. VEC maintains that the reserve group should not be maintained beyond January 1st of the subsequent RFP year (as the 2017 RFP specified). VEC contends that projects coming online under the most current RFP will result in lower costs to ratepayers over time and will not affect the total volume of projects procured through the program.

Discussion

I recommend that the Commission accept VEPP's proposal that the $15 per kW deposit be fully forfeited when a project is withdrawn prior to commissioning, except if the petition for a certificate of public good is denied. This proposal should increase the likelihood that RFP bids will be based on better planned, fully vetted projects and result in more standard-offer projects achieving commissioning. To implement this change in deposit requirements, I recommend that the Commission issue a revised standard-offer contract.

I recommend that the Commission continue the requirement that the reserve group not be maintained beyond January 1st of the subsequent RFP year. The reserve group facilitates "the goal of timely development of standard-offer projects by ensuring that if a project is withdrawn following its selection, another project may be contracted immediately."[13] Retiring the reserve group each year and developing a new one based on the most current RFP results ensures that current and viable projects are selected into the program and that these projects are the most cost-effective to ratepayers. The reserve group is retired on January 1st to provide any projects remaining on the list with sufficient lead time to participate in the next RFP and the Commission sufficient time to notice the program capacity available in the next RFP.

With regard to reallocating capacity for projects that have not met their standard-offer contract milestones, the Commission will allocate such capacity to the reserve group if one exists. In fact, the Commission recently substituted a project from the reserve group for a project that did not meet its contract milestones.[14]

C. RFP Timeline

Pursuant to Section 8005a(c)(1), the Commission is required annually, commencing on April 1 of each year, to increase the cumulative plant capacity of the standard-offer program (the annual increase) until the 127.5 MW cumulative plant capacity is reached.

Consistent with these statutory pace requirements, the Commission has required that by April 1 of each year, the Standard Offer Facilitator issue an RFP.[15] Under prior schedules in which the RFP was released on April 1st, bids were due one month from the release of the RFP and the award group was determined in early June with standard-offer contracts executed by July.

Participants' Comments

VEPP raises concerns about standard-offer projects needing extensions to contract commissioning milestones. VEPP suggests that a possible solution is to alter the RFP schedule. For example, if standard-offer contracts were executed later in the fall, the developers might have the entire year two summer construction season to build their projects, thereby minimizing the need for commissioning milestone extensions.

ANR provided general timelines of the natural resources studies and other studies that are often required to apply for and obtain a certificate of public good and suggested changes to the

[13] Dockets 7873 and 7874, Order of 3/1/13 at 28.
[14] *See Order Re Request for Standard Offer Contract*, Case 17-3952-PET and Docket 8817, Order of 12/14/17.
[15] Dockets 7873 and 7874, Order of 3/1/13.

implementation of the 2019 standard-offer program consistent with these timelines. Fundamental made suggestions for changing the 2019 program timeline. REV stated that it did not support changes to the RFP timeline that would result in a delay of awards past the timeline of late spring or early summer. Star Wind supports an RFP timeline that includes awards being made in the spring and RFP requirements being noticed well in advance of the RFP issuance.

GMP states that it is supportive of the goal to reduce the number of instances in which projects must request extensions to their commissioning milestones. GMP observes that there may be tradeoffs with respect to ratepayers. GMP contends that projects commissioned in the spring or early summer have immediate value to ratepayers because they contribute to reducing annual peak demand and thereby reduce Vermont's purchases of capacity in the following year's ISO-New England ("ISO-NE")[16] Forward Capacity Market.

VEPP also requests the RFP schedule (Section 2.1 of the 2017 RFP) be adjusted to allow the Standard Offer Facilitator up to three weeks to review proposals and provide recommendations to the Commission.

Discussion

I recommend that the Commission continue to issue the RFP by April 1 of each year. This timeline is consistent with the statutory pace requirements under Section 8005a(c)(1) and consistent with previous Commission Orders implementing the standard-offer program. No participant objected to this timeline for use in the 2018 RFP. While some participants suggested that for 2019 standard-offer program the RFP be issued in the fall of 2018, there was no consensus among participants, in particular those participants who represent the interests of potential bidders.

I also recommend that the Commission adopt VEPP's request that the RFP schedule be adjusted to allow the Standard Offer Facilitator up to three weeks to review proposals and provide recommendations to the Commission.

D. Program Implementation

Pursuant to Section 8005a(f)(1), the Commission is required to use a market-based mechanism, such as a reverse auction or other procurement tool, to obtain the authorized amount

[16] Authorized by the Federal Energy Regulatory Commission ("FERC"), ISO-NE serves as the independent system operator for the New England grid.

of renewable energy projects, if it first finds that use of the mechanism is consistent with applicable federal law and the goal of timely development at the lowest feasible cost. In 2013, the Commission established an RFP mechanism to solicit standard-offer projects.[17]

Participants' Comments

The Department recommends that the RFP require participants to submit open-book bids. This format would require any bidder of a project to provide full documentation of the cost estimates that informed their specific bid price. The bidder would be required to submit a bid comprised of five categories (installation costs, operating costs, replacement costs, decommissioning costs, and revenue streams) each with their own sub-category of items. The Department contends that an open-bid process will improve the cost-efficiencies of bids and allow for a more competitive RFP process, especially in the case where there is a separate allocation for certain technology categories.

BED and VPPSA suggest developing an analysis of locations that are well-suited to absorb additional generation rather than those areas that are becoming constrained. BED and VPPSA contend that an adjuster could be applied to the evaluation of RFP bids to reflect energy deliverability in order to give preference to the projects that will ultimately be the lowest-cost resources.

Allco suggests that the RFP include an additional set-aside for projects that would commit to a commissioning date that is within 12 months of the signature date of the standard-offer contract. Allco contends that these projects have added value because of their likelihood of being built. Allco recommends using a clearing price to establish the price paid to successful projects in the RFP rather than a price based on the bidder's submitted price. Allco contends that the price paid to any Provider Block project in a given year should be the highest bid price on the reserve list from the Competitive Developer Block. Allco also argues that the use of the RFP mechanism should be revisited to determine whether it is achieving its intended benefits. Allco also argues that price caps for each technology category should be based on the avoided cost of the Vermont composite system and not the cost to build and operate the system from the generator side.

[17] Dockets 7873 and 7874, Order of 3/1/13.

REV supports the current RFP mechanism. REV maintains that the current price caps are competitive and have resulted in lower program costs. REV raises concerns that the Provider Block winning bids are higher than similar projects in the Developer Block and requests that the Commission consider these price discrepancies when developing the 2018 program.

Discussion

I recommend that the Commission not adopt any changes to the current RFP mechanism with regard to the structure of the price caps or methodology for awarding projects. The Department's proposal to institute an open-bid process appears to add much complexity to the RFP bidding process without a clear demonstration that the proposal would improve the cost-efficiencies of bids and allow for a more competitive RFP process. Allco's proposal to create a set-aside for projects that would commit to a 12-month commissioning date appears to add additional burdens and complexity to the bid process without a clear demonstration of improved cost-efficiencies or substantial benefit over the current 24-month commissioning deadline. Further, Allco has not demonstrated that its proposal concerning clearing prices will improve the cost-efficiencies of the selected projects.

Finally, Allco, REV, BED, and VPPSA raise broader concerns about the implementation of the standard-offer program that are beyond the scope of this proceeding.[18] In Case 17-5257-INV, the Commission opened a proceeding to review the effectiveness of the standard-offer program with the goal to develop an improved, transparent, and methodologically sound framework for selecting standard-offer projects that will benefit the operation of the distribution system while fulfilling the statutory goal of the rapid deployment of standard-offer projects at the lowest feasible cost.

E. Sheffield-Highgate Export Interface

According to information presented to the Commission, the electric transmission system in northern Vermont has reached its capacity to integrate new generators without financial impact to existing generators. In 2013, ISO-NE demarcated the Sheffield-Highgate Export Interface ("SHEI") and established generator operation limits to ensure that the transmission system's capacity to function reliably remains intact. During certain operational periods, these

[18] Case 17-3935-INV, Order of 8/22/13.

limits are reached and generation resources in areas of northern Vermont are required to curtail their output due to the lack of transmission system capacity to export power. Through the Vermont System Planning Committee ("VSPC"), Vermont utilities and other stakeholders are currently discussing ways that the SHEI limitations can be addressed to reduce or eliminate curtailments of generation located within the interface.[19]

Participants' Comments

The Department recommends that the 2018 RFP restrict bids from projects in the SHEI area. The Department maintains that permitting the construction of additional generation in the SHEI area is likely to increase the number of hours during which curtailment of existing renewable projects will be necessary. The Department argues that the Commission has broad discretion in its administration of the program and has the authority to impose a moratorium on the construction of new standard-offer plants in the SHEI area. The Department maintains that any new project in the SHEI area could be rejected on the grounds that it would be incompatible with the renewable energy goal articulated in 30 V.S.A. § 8001(a)(7), which directs that all renewable energy be administered by "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 the grid through such means as reducing line losses and addressing transmission and distribution constraints."

GMP supports restricting 2018 RFP bids from projects in the SHEI area. GMP contends that although the Commission may not have the authority to redefine the statutory eligibility requirements of the standard-offer program, it has the authority under Section 8005a(f)(2)(B), to set appropriate avoided cost caps that accurately reflect lower avoided costs for projects located in the SHEI area, or to exclude those projects altogether. GMP states that it is not aware of a method to reliably estimate a reduction in avoided costs that could be applied generically to various standard-offer technologies, thus a temporary cessation of RFP procurement of projects located in the SHEI area is the most practical result.

In the alternative, the Department and GMP recommend that the Commission include in the RFP information regarding the SHEI constraint issues, and require bidders to affirmatively

[19] More information on SHEI can be found at: https://www.vermontspc.com/grid-planning/shei-info.

indicate whether the proposed project is in that area. GMP recommends that the RFP include the following information: (1) language that identifies the SHEI; (2) an explanation that proposed projects within this area could adversely impact the operation of other renewable generation in the area; and (3) as a result, new generation projects (including standard-offer projects) located in the SHEI area could face opposition in the certificate of public good process.

BED, VPPSA, VEC, and WEC also support restricting 2018 RFP bids from projects in the SHEI area. VEC and WEC note that the constraints in the SHEI region have resulted in the curtailment of the output of existing projects in the SHEI and lower revenues for other resources in the region. BED and VPPSA argue that any moratorium on standard-offer generation within the SHEI area should not be construed to apply to utility-owned projects within that area.

REV argues that any limitations or alternative bid evaluation for projects within the SHEI area should be considered for only one year and should be for projects greater than 500 kW in size. REV also maintains that any limitations should equally apply to Provider Block and Developer Block projects.

Discussion

The Commission has recognized the concerns that transmission system constraints in northern Vermont are increasingly limiting the amount of generation that can operate simultaneously in the area.[20] While ISO-NE demarcated SHEI and established generator operation limits to ensure that the transmission system's capacity to function reliably remains intact, these limits vary automatically in real time based on actual system conditions, such as load, generation, and equipment status. Thus, it is difficult to develop a map or other device that could serve to identify the precise boundary points on the transmission system where a moratorium should be imposed. Any map developed today could be obsolete by the time standard-offer projects procured in the 2018 RFP are built and operating.

Given these realities, it is not appropriate to impose a moratorium in the SHEI area for standard-offer plants solicited in the 2018 RFP. Instead, I recommend that the Commission include language in the 2018 RFP that addresses the concerns identified in the SHEI area. Specifically, I recommend the 2018 RFP include the following: (1) a short description of the SHEI area and limitations, including a link to the VSPC webpage addressing the SHEI area; (2)

[20] *Notice of Workshop*, Case No. 17-5219-INV, Order of 12/22/17.

an explanation that proposed projects within the SHEI area could adversely impact the operation of other renewable generation in the area; and (3) a notice to bidders that any standard-offer projects proposed in the SHEI area will have to address the economic and transmission system concerns during the certificate of public good process.

E. Transmission Costs

In Docket 8693, the Commission opened an uncontested proceeding to address the issue that standard-offer projects have located predominantly in one utility's service territory. This has resulted in the generation of power far in excess of that service territory's *pro rata* share that then must be wheeled to other service territories.

Participants' Comments

The Department, VEC, WEC, and GMP recommend that the standard-offer contract be amended to include a provision requiring generators to arrange for transmission services with the interconnecting utility. Under the proposal, participating standard-offer generators will not be required to pay for any transmission charges. The Standard Offer Facilitator will continue to arrange for wheeling transmission and the distribution utilities will continue to pay for wheeling. This proposed language will require that generators execute the transmission service applications and agreements. To implement this proposal, VEC and WEC propose that the Commission add the following provision to the standard-offer contract:

> 14. TRANSMISSION SERVICES
>
> Producer shall be responsible for arranging for any transmission services required under the terms of the Interconnecting Utility's duly approved transmission tariff, if any, including executing applications for transmission service and transmission service agreements, provided however that, by virtue of participation in the Standard Offer Program, the Producer will not be charged for any transmission costs, which will be billed by the Facilitator to the Vermont Distribution Utilities participating in the Standard Offer Program.

VEC and WEC represent that the parties to Docket 8693 intend to submit the proposed contract language in that docket as well.

Allco argues that the distribution utilities should handle all administrative aspects of transmission services and not burden standard-offer generators with executing applications for transmission service and transmission service agreements.

Discussion

Certain participants in this proceeding have proposed to amend the standard-offer contract to address the need for transmission wheeling of some standard-offer projects. Docket 8693 has been opened to address this issue. While I understand the participants' concerns to have this issued resolved before any standard-offer contracts are issued for the 2018 RFP, the issue is more appropriately addressed in Docket 8693. Accordingly, I recommend that the Commission not address this issue here.

V. TECHNOLOGY ALLOCATION

Pursuant to 30 V.S.A. § 8005a(c)(2), the Commission must allocate the 127.5 MW cumulative plant capacity of the standard-offer program among different categories of renewable energy technologies. Section 8005a(c) does not specify a methodology for allocating across technology categories and the Commission has adopted a flexible approach in past standard-offer proceedings.

In 2016, the Commission established a mechanism for the allocation of available capacity that included a Price-Competitive Developer Block and a Technology Diversity Developer Block. Under the 2016 established mechanism, 2.2 MW of the available Developer Block program capacity was available to projects of any technology category, awarded on bid price (the "Price-Competitive Developer Block"). The remainder of the Developer Block capacity – estimated to be approximately 4.175 MW in 2016 – was allocated on an equal basis to non-solar technology categories,[21] awarded on bid price within each category (the "Technology Diversity Developer Block"). Each technology under the Technology Diversity Developer Block was allocated approximately 696 kW of capacity.[22]

In 2017, the Commission again established a Price-Competitive Developer Block and a Technology Diversity Developer Block. Pursuant to Section 8005a(c)(1)(D), the Commission also established a Preferred Location Block.[23] Under the 2017 RFP, 2.2 MW of the available Developer Block program capacity was available to the Price-Competitive Developer Block for

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[21] The non-solar technology categories currently include hydroelectric, biomass, large wind, small wind, landfill gas, and food waste anaerobic digestion.

[22] *Order re Standard Offer Program Technology Allocation*, Dockets 7873 and 7874, Order of 2/12/16.

[23] Pursuant to Section 8005a(c)(1)(D), under the pilot program, for one year commencing on January 1, 2017, one-sixth of the annual increase was allocated to projects located over parking lots or on parking lot canopies and one-sixth of the annual increase was allocated to standard-offer projects at other preferred locations.

projects of any technology category, awarded on bid price. The remainder of the Developer Block capacity – estimated to be approximately 2.686 MW in 2017 – went to the Technology Diversity Developer Block and was allocated on an equal basis to small wind and food waste anaerobic digestion categories, awarded on bid price within each category.[24]

Annual Increase

Pursuant to 30 V.S.A. § 8005a(c)(1)(A), the annual increase to the standard-offer program capacity is 7.5 MW for the year 2018. In addition, pursuant to Section 8005a(c)(1)(B)(ii), any unsubscribed capacity from the Provider Block is added to the annual increase. For the 2017 RFP, there was no unsubscribed Provider Block capacity.

In 2018, pursuant to Section 8005a(c)(1)(B)(i), 15% of the annual increase shall be allocated to the Provider Block. Accordingly, for the 2018 RFP, 1.125 MW shall be allocated to the Provider Block and 6.375 MW shall be allocated to the Developer Block.

Participants' Comments

The Department maintains that the results of the past two RFPs demonstrate that there has not been sufficient competition in the Technology Diversity Developer Block to induce downward pressure on the RFP bids of non-solar projects. In support of its claim, the Department points to the results of the 2017 RFP, which had separate blocks for small wind and food waste anaerobic digestion projects, and the results of the 2016 RFP, which had separate blocks for large wind, small wind, and food waste anaerobic digestion projects. The Department notes that in 2017, thirteen bids were made in the block for small wind projects by two developers and all bids were at or near the technology-specific price cap, and two bids were made in the block for food waste anaerobic digestion projects and were at or near the technology-specific price cap. In 2016, there were four bids in the block for small wind projects at the price cap and one bid in the block for large wind projects at the price cap. By comparison, the Department notes that the lowest bid for solar projects was more than 30% below the 2017 solar price cap and more than 40% below the 2016 solar price cap. The Department supports the creation of a Technology Diversity Developer Block on the condition that open-book bidding is established as a requirement for winning a standard-offer contract.

[24] Docket 8817, Order of 3/2/17.

GMP, BED, and VPPSA recommend that the technology allocation implemented in the 2017 RFP be again used in the 2018 RFP, with the exclusion of the pilot program mandated by Section 8005a(c)(1)(D). BED and VPPSA also recommend assigning approximately 4.4 MW of capacity to the Price-Competitive Developer Block. BED and VPPSA argue that having all technologies that have a price cap lower than or equal to that of solar compete for contracts on a cost basis, while allocating set capacity amounts to those technologies with higher price caps, balances the statutory goals of achieving technology diversity and providing the lowest feasible cost to ratepayers.

REV recommends that the technology allocation implemented in the 2016 RFP be used in the 2018 RFP. REV argues that a Technology Diversity Developer Block that separately allocates to all non-solar technologies is consistent with Section 8005a(c)(2) that requires the Commission to allocate the 127.5 MW cumulative plant capacity among different categories of technologies. REV further argues that the 2016 RFP methodology is consistent with the statutory goals for renewables set out in 30 V.S.A. §§ 8001 and 8005a. REV contends that the current lack of technology diversity in the standard-offer program further supports the 2016 RFP methodology.

Allco supports the elimination of technology allocations with one exception – storage. Allco argues that the current allocation methodology raises costs for ratepayers without providing added benefit to ratepayers. Allco maintains that storage, on the other hand, as part of a renewable energy project provides significant additional benefit to ratepayers and that these benefits have been quantified in recent solar/storage projects proposed by GMP.

Purpose and Dynamic support the capacity allocation used in the 2017 RFP. Purpose and Dynamic maintain that because food waste anaerobic digestion projects are likely to range between 100 kW and 1 MW in size, having a capacity allocation larger than 1 MW ensures the opportunity for at least two projects to be awarded in this category.

Fundamental and Star Wind recommend that the technology allocation implemented in the 2017 RFP be again used in the 2018 RFP. Fundamental further recommends that the pilot program allocation from 2017 be added back to the Technology Diversity Developer Block.

<u>Discussion</u>

Section 8005a(c) specifies the annual pace of the standard-offer program and that the overall program shall include an allocation across specific technologies. Unlike the specific instructions for the provider/developer allocations, Section 8005a(c) does not specify a methodology for allocating across technology categories, but instead provides the Commission with the opportunity to adopt a flexible approach. Recognizing the flexibility allowed in statute, the Commission has modified the technology allocation mechanism in response to participants' recommendations, previous RFP results, and statutory changes such as the one-year pilot program for preferred locations in 2017.

As identified in previous Commission Orders, the implementation of a technology allocation mechanism has been guided by the applicable statutory goals and directives of Sections 8001 and 8005a, as well as the goal that the mechanism for a technology allocation be stable, predictable, and transparent.[25] The Commission has further recognized that any technology allocation must balance statutory goals and directives that may seemingly be at odds. For instance, including a diversity, both in size and in technology, of renewable energy projects in Vermont's retail electric supply portfolio, may conflict with ensuring the timely development of such projects at the lowest feasible cost. The Commission also has recognized that the technology allocation must take into consideration the varying market interest in developing projects from each technology category.

Several of the participants in this proceeding recommend that the Commission adopt technology allocations for this year's RFP that represent some variation on the approaches taken for the 2016 and 2017 RFPs. While the approaches taken by the Commission in 2016 and 2017 differ, they both involved a structure that included a Price-Competitive Developer Block and a Technology Diversity Developer Block.

I recommend that the Commission adopt the technology allocation used in the 2016 RFP, with one modification. Under my recommended approach, the allocated capacity in the Price-Competitive Developer Block would be made available to projects of any technology category, awarded on bid price. The allocated capacity in the Technology Diversity Developer Block would be divided evenly among all the non-solar technologies, except landfill gas. Based upon past information about landfills presented to the Commission, the opportunities for landfill gas appear to be limited to already developed projects. Thus, it is not necessary to set aside an allocation for this category.

[25] *See* Dockets 7873 and 7874, Order of 2/12/16; Docket 8817, Order of 3/2/17.

My recommendation is guided by my review of participants' recommendations, past RFP results, and existing capacity that has been built under the standard-offer program. The majority of standard-offer projects built to date have been solar projects, with a small amount of capacity filled by biomass, hydroelectric, and landfill projects.[26] To date no small wind, large wind, or food waste anaerobic digestion projects have been built. The Commission has received bids for these types of projects in past RFPs and standard-offer contracts have been awarded to small and large wind projects, but none of these projects have been commissioned. Based on the current diversity of the standard-offer program, it is appropriate to maintain a separate allocation for non-solar technologies.

It is reasonable to assume that technology categories with price caps lower than or equal to solar are able to compete with solar projects in the Price-Competitive Developer Block. However, when this approach was implemented in the 2017 RFP, only bids for solar projects were received in the Price-Competitive Developer Block. The diversity of the standard-offer program still remains a concern. My recommended technology allocation should encourage a diversity of standard-offer projects. The establishment of price caps for each technology category limits the costs incurred by ratepayers and therefore, balances the statutory goals and directives that include ensuring a diversity of projects at the lowest feasible cost.

I recommend that the Commission continue to review the allocation methodology annually to ensure that reasonable diversity is achieved under the standard-offer program. While it may be appropriate to retain a Technology Diversity Developer Block for the remainder of the program, the Commission may want to adjust in future RFPs the technology categories included in the block based on RFP results and projects built. For example, the Commission may consider removing the biomass and hydroelectric categories because the opportunities for these projects appear to be limited.

Consistent with previous Commission Orders, I recommend that all unused capacity that was allocated to the Technology Diversity Developer Block be made available to the Price-Competitive Developer Block. All remaining unselected developer bids will be ranked based on the price offered, ordered from lowest to highest. Standard-offer contracts will be offered to

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[26] The standard-offer program also includes several farm methane projects that do not compete in the RFP process.

those proposals with the lowest bid price until the remaining annual capacity allocated for the Price-Competitive Developer Block has been filled.

I also recommend that the Commission continue allowing the capacity caps on the Price-Competitive Developer Block and the Technology Diversity Developer Block to be exceeded if the marginal bid exceeds the remaining space for that block (i.e., once the annual capacity cap is approached but not exceeded, the proposal that would cause the size of the award group to exceed the annual capacity cap by no more than 2.2 MW would be included in the award group). This approach encourages timely development of standard-offer projects and recognizes that future years' capacity solicitations may be reduced by the extra capacity that was awarded. Because 2.2 MW is the maximum project size eligible for the standard-offer program, there is a limit to the extent any single project can exceed the annual cap.

In addition, consistent with previous Commission Orders, I recommend that the annual capacity cap in the Provider Block serve as the hard cap on the size of an eligible project, rather than the 2.2 MW standard-offer project cap. As the Commission has previously stated, the determination of hard caps for projects under the Provider Block is guided by the enabling legislation for the standard-offer program establishing annual limits for these blocks. The Legislature set annual caps for these project blocks with the full understanding that plants up to 2.2 MW would otherwise be eligible to receive standard-offer contracts. Thus, it is reasonable to conclude that these statutorily mandated annual limits were intended to serve as hard caps on the size of the projects in these blocks. The size of the Provider Block for 2018 is 1.125 MW. Consistent with the statute, I recommend this size serve as the maximum size of an allowable project in the Provider Block.

Consistent with previous Commission Orders, I recommend that the capacity cap on the Provider Block be allowed to be exceeded if the marginal bid exceeds the remaining space for the block and the project is not larger than the hard cap of 1.125 MW. This approach encourages timely development of provider projects and recognizes that future years' capacity solicitations for provider projects may be reduced by the extra capacity that was awarded.

In summary, for implementation in the 2018 RFP, I recommend that the Commission adopt a technology allocation under which the Developer Block includes a Price-Competitive Developer Block of 2.2 MW of program capacity that is available to projects of any technology category, awarded on bid price. The remainder of the Developer Block capacity – estimated to be approximately 4.175 MW – is allocated to the Technology Diversity Developer Block. This block will be allocated on an equal basis to non-solar technology categories (except landfill gas), awarded on bid price within each category.

The table below shows the approximate capacity allocation I am recommending for the 2018 RFP.

2018 Standard-Offer Program Technology Allocation	
Price-Competitive Developer Block	2.2 MW
Technology Diversity Developer Block	
Biomass	0.835 MW
Large Wind	0.835 MW
Small Wind	0.835 MW
Food Waste Anaerobic Digestion	0.835 MW
Hydroelectric	0.835 MW
Provider Block	1.125 MW
Total Annual Increase	**7.5 MW**

VI. AVOIDED COST PRICE CAPS

The Commission established technology-specific avoided costs to serve as caps on the standard-offer prices solicited through the RFP. Pursuant to Section 8005a(f)(3), the Commission is required to annually review these established avoided costs. In addition, Section 8005a(f)(2)(B) identifies criteria the Commission may consider in establishing an avoided-cost price cap.

In 2017, pursuant to Section 8005a(f)(3), the Commission determined the technology-specific avoided costs that served as price caps on the standard-offer projects solicited through the 2017 RFP.[27] In addition, the Commission determined the avoided costs that served as the prices for farm methane projects under the standard-offer program.[28]

[27] Docket 8817, Order of 3/2/17; Docket 8817, Order of 3/29/17.

[28] Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap, so these projects do not compete in the market-based RFP process.

A. Solar Price Caps

In 2017, the Commission established an avoided-cost price cap of $0.130 per kWh for solar projects solicited through the RFP.

Participants' Comments

The Department reviewed the assumptions and cash-flow model used to determine the existing solar price cap. The cash-flow model, which was developed collaboratively by stakeholders in Docket 7533, has been used by the Commission in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment.[29] Based on that review, the Department made specific recommendations regarding the assumptions to be used as inputs for the cash-flow model for solar projects.

The Department recommends changing several assumptions used in the cash flow model, including the assumptions addressing inflation, working capital reserves, financing costs, allowable bonus depreciation of the federal investment tax credit ("ITC"), rate of return, installation costs, maintenance costs, land lease costs, and inverter replacement costs. In particular, the Department recommends reduced financing costs of 2% charged on total debt principal for lender's fees plus an annual percentage rate ("APR") of 3% charged on the total debt principal to cover interest during construction. The Department proposes lowering the rate of return to 8.75%, consistent with GMP's current return on equity. The Department also recommends that installation costs be reduced by 10% and maintenance costs be reduced by approximately 50%. The Department proposes that land lease costs be reduced to $875 per acre and inverter replacement costs be reduced to $234,000.

REV challenged the Department's assumptions concerning land least costs, the Vermont ITC, and financing costs. REV maintains that land lease costs for solar projects should remain at the 2017 value of $1,500 per acre. REV argues that the state ITC is realized at rate of 0 to 10%, rather than the 50% proposed by the Department. REV contends that financing costs should remain at 2017 values of 3% charged on total debt principal for lender's fees plus an APR of 5% charged on the total debt principal to cover interest during construction, rather than the 2% and

[29] *See* Docket 7533, Order of 1/15/10; Docket 7780, Order of 1/23/12; Docket 7874, Order of 3/1/13; Docket 7874, Order of 3/10/15; Docket 7874, Order of 3/7/16; and Docket 8817, Order of 3/2/17.

3% proposed by the Department. REV maintains that the price of solar panels is likely to go up given the recently announced International Trade Commission decision to impose an import tariff on solar panels.

GMP contends that past RFP results indicate that there has been a competitive market for solar projects and that RFP bids have been uniformly under the current $0.13 per kWh price cap. GMP believes that the current price cap may be higher than is presently necessary to ensure developer participation, but GMP also realizes that there is uncertainty in the solar marketplace reflecting recently announced import tariffs on solar panels. GMP states that based on the uncertainty associated with the import tariff and the history of price competition among the Competitive-Price Developer Block, it is not clear that the price cap for solar projects needs to be lowered.

Discussion

As in past standard-offer proceedings, I recommend that the Commission establish standard-offer prices based on the assumption that the projects being developed are reasonably efficient in an effort to balance the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers. This means that projects are sited and financed so as to avoid excessive costs to electric ratepayers.[30]

The Department recommends several changes to the assumptions used to determine the 2017 solar avoided-cost price cap of $0.130 per kWh. On balance, the Department's recommendations reduce the existing price by approximately $0.01 per kWh. The reduction in price is primarily driven by the reduction in installation costs and inverter replacement costs.

REV raises concerns about land lease costs, debt financing costs, and investment tax credits, but provides no project-specific information to challenge the accuracy of the Department's recommended assumptions. The Department has provided documented and reasonable assumptions from its expert, including those concerning land lease costs, debt financing costs, and the realization rate for the state ITC. The Department's assumption on the state ITC remains unchanged from the assumptions used to establish the 2017 solar price cap and

[30] See Docket 7533, Order of 1/15/10, Docket 7780, Order of 1/23/12, Docket 7874, Order of 3/7/16; and Docket 8817, Order of 3/2/17.

appropriately recognizes that projects may have limited ability to claim the tax credit. While the Department has proposed changes to lender's fees and the rate charged on the total debt principal to cover interest during construction, the assumptions on capital structure and rates charged on short-term and long-term debt remain unchanged from the assumptions used to establish the 2017 price cap. The proposed assumptions allow a reasonable amount of flexibility in capital structures that should allow for a range of developers to participate in the RFP, even if the capital structure assumptions in the cash-flow model do not apply to all developers equally.

While the Department has proposed reasonable updates to the assumptions used in the cash-flow model, the Department's recommended assumptions do not reflect the new tariffs on imported solar panels issued by the US Trade Representative on January 23, 2018,[31] or the tax changes that became law on December 22, 2017.[32] The US Trade Representative ruling adds a 30 percent tariff on imported solar panels and modules that declines to 15% over the next four years, and takes effect after the first 2.5 gigawatts' worth of imported capacity. As reported in trade press, the changes to the tax code include a reduction of corporate tax rates — from 35% to 21%. The new tax code also includes changes to depreciation expenses, allowing companies to deduct 100% of the cost of business equipment placed in service rather than the previously allowed first-year "bonus depreciation" deduction of 50%. The tax code changes also include changes to the handling of business operating losses, reducing the maximum amount of total income that can be offset with net operating losses in a given year.

Because the tariffs on solar panels have been recently imposed, it is difficult to predict what effect they will have on the domestic cost of solar panels. It is possible the costs of panels may increase over the next few years, but these potential increases may be offset by other predicted cost declines.[33] The new tax code is reported to reduce the corporate tax rate and allows increased depreciation expenses, but it is unclear whether the changes to the handling of business losses will result in a possible offset to these tax reductions. Without specific information on how the new tax code will be implemented, changing the assumptions in the cash-flow model addressing the corporate tax rate and depreciation expenses becomes an uncertain exercise at this time.

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[31] *See* https://ustr.gov/sites/default/files/files/Press/fs/201%20Cases%20Fact%20Sheet.pdf.

[32] *See* https://www.congress.gov/bill/115th-congress/house-bill/1/text.

[33] As the Department has noted in its comments, Lawrence Berkeley National Laboratory has predicted a decline in solar installation costs: https://emp.lbl.gov/publications/tracking-sun-10-installed-price.

Recognizing the uncertainties related to the new import tariffs and the tax code changes, I recommend that the Commission not change the solar price cap that was established in 2017. It is possible that the tax code changes will offset any cost increases associated with the import tariffs and that the Department's recommended assumptions will result in a reasonable and appropriate price cap. However, this conclusion is not a certainty. Past RFP results with multiple bids to develop solar projects indicate that there is sufficient interest in developing solar projects, and this rate of participation should result in competitively priced bids. Thus, a price cap of $0.130 per kWh balances the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers.

Accordingly, for the 2018 RFP, I recommend the Commission establish an avoided cost for solar projects of $0.130 per kWh, fixed over the life of the project.

B. Small Wind Price Cap

In 2017, the Commission established an avoided-cost price cap of $0.258 per kWh for small wind projects solicited through the RFP.

Participants' Comments

The Department reviewed the assumptions and cash-flow model used to determine the existing small wind price cap. As discussed above, the cash-flow model has been used by the Commission in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment. Based on that review, the Department made specific recommendations regarding the assumptions to be used as inputs for the cash-flow model for small wind projects.

The Department recommends changing several assumptions used in the cash flow model, including the assumptions addressing inflation, working capital reserves, financing costs, federal and state ITCs, allowable bonus depreciation of the federal ITC, rate of return, maintenance costs, and land lease costs. In particular, the Department recommends reduced financing costs of 2% charged on total debt principal for lender's fees plus an APR of 3% charged on the total debt principal to cover interest during construction. The Department proposes adjustments to the assumptions to reflect that small wind projects are not eligible for a state or federal ITC. The Department proposes lowering the rate of return to 8.75%. The Department also recommends that maintenance costs be reduced from approximately $75 per kW-year to $42 per kW-year. The Department proposes that land lease costs be reduced to $875 per acre.

REV challenged the Department's assumptions concerning land least costs, interconnection costs, capital structure, and financing costs. REV maintains that land lease costs for wind projects should be $1,500 per acre rather the $875 per acre proposed by the Department. REV maintains that interconnection costs for wind projects are 2 to 6 times higher than the Department's value of $40,000. REV contends that financing costs should remain at 2017 values of 3% charged on total debt principal for lender's fees plus an APR of 5% charged on the total debt principal to cover interest during construction, rather than the 2% and 3% proposed by the Department. REV also argues that the capital structure for wind projects should only include long-term debt that is 60% of financing at a rate of 5% for a term of 15 years, rather than the Department's recommendation that includes short-term debt that is 30% of financing starting at a rate of 3.5% for a term of 6 years, and long-term debt that is 30% of financing at a rate of 4.5% for a term of 18 years.

Fundamental recommends that the existing small wind price cap be increased by 12.8%. Fundamental maintains that the costs of equipment, labor, land, and permitting have risen by 17.8%. Fundamental contends that the federal ITC realization rate should be 6% and that annual inflation should be set at 2.2%. Fundamental states that the price cap should include costs associate with a maintenance reserve, annual output degradation, and inverter replacement costs. Fundamental also argues that the internal rate of return should be set higher than 9.02%.

Star Wind recommends that the existing small wind price cap be increased by 20%. Star Wind maintains that installation costs have increased by 10% due to increased material costs and the new sound standards. Star Wind also maintains that land lease costs have increased due to setback requirements. Star Wind contends that the federal ITC realization rate should be 12% and no state ITC should be included. Star Wind states that the price cap should include costs associated with permitting and inverter replacement costs.

GMP suggests that the avoided cost caps for small wind (as well as all technologies other than solar) should remain unchanged at this time in order to maintain the opportunity for developers working on these technologies to participate in the standard-offer program. GMP contends that the 2017 RFP results (the small wind project bids were all at or near the price cap and the majority of projects were proposed by only a few developers) suggest that there is limited competition for this technology, and that projects could potentially be developed at prices lower than the current price cap. However, GMP further states that because small wind projects have not yet completed permitting and construction, and the scale of projects is limited, it seems reasonable to maintain the current price cap for the 2018 RFP.

Discussion

Consistent with my recommendation for solar projects, I recommend that the Commission establish the standard-offer price for small wind projects based on the assumption that the projects being developed are reasonably efficient in an effort to balance the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers. This means that projects are sited and financed so as to avoid excessive costs to electric ratepayers.

The Department recommends several changes to the assumptions used to determine the 2017 small wind avoided-cost price cap of $0.258 per kWh. On balance, the Department's recommended assumptions increase the existing price by more than $0.01 per kWh. The increase in price is primarily driven by the adjustments made to reflect that small wind projects are not eligible for a state or federal ITC.

Fundamental, REV, and Star Wind raise concerns about installation costs, land lease costs, debt financing costs, capital structure, and investment tax credits, but provide no project-specific information to challenge the accuracy of the Department's recommended assumptions. The Department has provided documented and reasonable assumptions from its expert, including those concerning installation costs, land lease costs, debt financing costs, and capital structure. The Department's assumption on the state and federal ITC appropriately recognizes that small wind projects do not have the ability to claim these tax credits. While the Department has proposed changes to lender's fees and the rate charged on the total debt principal to cover interest during construction, the assumptions on capital structure and rates charged on short-term and long-term debt remain unchanged from the assumptions used to establish the 2017 price cap. Similar to solar projects, the proposed assumptions allow a reasonable amount of flexibility in capital structures that should allow for a range of developers to participate in the RFP, even if the capital structure assumptions in the cash-flow model do not apply to all developers equally. With respect to installation costs for small wind projects, the Department's recommendation does not change the 2017 assumption of $5.80 per watt (an assumption that includes interconnection costs), derived from a Lawrence Berkeley National Laboratory study. Star Wind and Fundamental have not presented documented information demonstrating that a higher cost is reasonable and that these installation costs are not representative of an efficiently sited project. The land lease costs assume that a project is efficiently sited. Star Wind has not presented documented information as to why these lease costs are not representative of a project in compliance with any applicable sound standards.

While the Department has proposed reasonable updates to the assumptions used in the cash-flow model, the Department's recommended assumptions do not reflect the recent tax law changes. As discussed with solar projects, the new tax code is reported to reduce the corporate tax rate and allows increased depreciation expenses, but it is unclear whether the changes to the handling of business losses will have any possible offset to these tax reductions. Without specific information on how the new tax code will be implemented, changing the assumptions in the cash-flow model addressing the corporate tax rate and depreciation expenses becomes an uncertain exercise at this time.

Recognizing the uncertainties related to the tax code changes, I recommend that the Commission not change the small wind price cap that was established in 2017. The recent tax code changes will possibly offset the loss of the ability of small wind projects to claim the state and federal ITC. Thus, combining the Department's recommended assumptions with the tax code changes, it is possible that the price cap will be similar to the 2017 value. It is also important that the established price cap not discourage developer participation in the RFP, especially given the concerns about technology diversity under the standard-offer program. A price cap of $0.258 per kWh, unchanged from 2017, balances the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers.

Accordingly, for the 2018 RFP, I recommend that the Commission establish an avoided cost for small wind projects of $0.258 per kWh, fixed over the life of the project.

C. Food Waste Anaerobic Digestion Price Cap

In 2017, the Commission established an avoided-cost price cap of $0.208 per kWh for food waste anaerobic digestion projects solicited through the RFP.

Participants' Comments

The Department reviewed the assumptions and cash-flow model used to determine the existing price cap for food waste anaerobic digestion projects. As discussed above, the cash-flow model has been used by the Commission in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment. Based on that review, the Department made specific recommendations regarding the assumptions to be used as inputs for the cash-flow model for food waste anaerobic digestion projects.

The Department recommends changing several assumptions used in the cash flow model, including the assumptions addressing inflation, debt repayment reserves, financing costs, capital structure, depreciation expenses, installation costs, maintenance costs, and land lease costs. In particular, the Department recommends reduced financing costs of 2% charged on total debt principal for lender's fees plus an APR of 3% charged on the total debt principal to cover interest during construction. The Department proposes the inclusion of a debt repayment reserve, similar to solar and wind projects. The Department recommends a capital structure similar to wind and solar projects that includes short-term debt that is 30% of financing starting at a rate of 3.5% for a term of 6 years and long-term debt that is 30% of financing at a rate of 4.5% for a term of 18 years. The Department proposes adjustments to the methodology for depreciating installation costs. The Department also proposes lowering the rate of return to 8.75%. The Department recommends that installation costs be reduced from $11,525 per kW to $10,400 per kW and maintenance costs be increased from approximately $1,108 per kW-year to $1,200 per kW-year. The Department proposes that land lease costs be reduced to approximately $1,000 per acre.

REV contends that financing costs should be 3% charged on total debt principal plus an APR of 5% charged on the total debt principal to cover interest during construction, rather than the 2% and 3% proposed by the Department.

Dynamic and Purpose argue that the price cap for food waste anaerobic digesters should include the costs of de-trashing infrastructure that would allow these projects to accept package food waste material and not just liquid waste feedstocks. Dynamic and Purpose also argue that the price cap should include costs of removing phosphorus from the digester effluent because the final disposition of the effluent is likely to be through a municipal wastewater treatment plant and not land application. Dynamic and Purpose contend that property tax assumptions should recognize that these projects do not qualify for use-value appraisal like farm methane projects. Dynamic and Purpose argue that the price cap should capture the complexity and risks of project operation and the benefits that the project provides in meeting Vermont's policy goals.

Discussion

Consistent with my recommendation for solar and small wind projects, I recommend that the Commission establish the standard-offer price for food waste anaerobic digestion projects based on the assumption that the projects being developed are reasonably efficient in an effort to balance the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers. This means that projects are sited and financed so as to avoid excessive costs to electric ratepayers.

The Department recommends several changes to the assumptions used to determine the 2017 food waste anaerobic digestion avoided-cost price cap of $0.208 per kWh. On balance, the Department's recommended assumptions result in the existing price being relatively unchanged.

Dynamic, Purpose, and REV raise concerns about installation costs, land lease costs, debt financing costs, but provide no project-specific information to challenge the accuracy of the Department's recommended assumptions. The Department has provided documented and reasonable assumptions from its expert, including those concerning installation costs, land lease costs, and debt financing costs. While the Department has proposed changes to lender's fees and the rate charged on the total debt principal to cover interest during construction, the assumptions on capital structure and rates charged on short-term and long-term debt remain unchanged from the assumptions used to establish the 2017 price cap. Similar to solar and small wind projects, the proposed assumptions allow a reasonable amount of flexibility in capital structures that should allow for a range of developers to participate in the RFP, even if the capital structure assumptions in the cash-flow model do not apply to all developers equally. With respect to installation costs, Dynamic and Purpose argue that the costs should include de-trashing infrastructure and costs of removing phosphorus, but have not presented specific documented information demonstrating why these costs are reasonable and that these installation costs are representative of an efficiently sited project. The land lease costs include property taxes, addressing the concerns of Dynamic and Purpose that these projects do not qualify for use-value appraisal like farm methane projects. Dynamic and Purpose also argue that the price cap assumptions should address other project risks and benefits, but do not provide specific examples to incorporate these concerns or why these costs are representative of an efficiently sited project.

While the Department has proposed reasonable updates to the assumptions used in the cash-flow model, the Department's recommended assumptions do not reflect the recent tax law changes. As discussed for solar and small wind projects, the new tax code is reported to reduce the corporate tax rate and allows increased depreciation expenses, but it is unclear whether the changes to the handling of business losses will have any possible offset to these tax reductions. Without specific information on how the new tax code will be implemented, changing the assumptions in the cash-flow model addressing the corporate tax rate and depreciation expenses becomes an uncertain exercise at this time.

Recognizing the uncertainties related to the tax code changes, I recommend that the Commission not change the food waste anaerobic digestion price cap that was established in 2017. The Department's recommended assumptions, along with the tax code changes, will likely result in a price cap that is lower than the 2017 value. However, as discussed above, it is difficult to implement the tax code changes at this time. It is also important that the established price cap not discourage developer participation in the RFP, especially given the concerns about technology diversity under the standard-offer program. A price cap of $0.208 per kWh, unchanged from 2017, balances the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers.

Accordingly, for the 2018 RFP, I recommend that the Commission establish an avoided cost for food waste anaerobic digestion projects of $0.208 per kWh, fixed over the life of the project.

D. Price Caps for Biomass, Hydroelectric, Landfill Gas, and Large Wind Projects

In 2017, the Commission established avoided-cost price caps of $0.125 per kWh for biomass projects, $0.090 per kWh for landfill gas projects, $0.130 for new hydroelectric projects,[34] and $0.107 per kWh for large wind projects solicited through the RFP.

[34] Pursuant to Section 8005a(p), existing hydroelectric plants with a capacity of 5 MW or less are eligible for standard-offer contracts based on prices determined according to the requirements of Section 8005a(p)(3).

Participants' Comments

The Department recommends no changes to the price caps for biomass, new hydroelectric, landfill gas, and large wind projects. No other participant filed specific recommendations for these price caps.

Discussion

No participant provided specific recommendations for revising the existing standard-offer price caps for biomass projects, hydroelectric projects, landfill gas projects, or large wind projects. In addition, based upon past information presented to the Commission on landfills in Vermont, the opportunities for landfill gas appear to be limited to already developed projects. Thus, I recommend the Commission maintain the avoided-cost price caps for these technologies established in 2017.

Accordingly, for the 2018 RFP, I recommend that the Commission establish the following avoided costs: $0.107 per kWh for large wind projects, fixed over the life of the project; $0.130 per kWh for new hydroelectric projects, fixed over the life of the project; $0.125 per kWh for biomass projects, levelized over life of project; and $0.090 per kWh for landfill gas projects, levelized over the life of the project.

E. Farm Methane Price Caps

In 2017, the Commission established an avoided cost of $0.145 per kWh for farm methane projects with a nameplate capacity greater than 150 kW ("large farm methane"), and an avoided cost of $0.199 per kWh for farm methane projects with a nameplate capacity less than or equal to 150 kW ("small farm methane").

Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap, and thus do not participate in the annual RFP. Farm projects can receive a 20-year contract at any time by contacting the Standard Offer Facilitator.

Participants' Comments

The Department reviewed the assumptions and cash-flow models used to determine the existing standard-offer prices for small and large farm methane projects. As discussed above, the cash-flow model has been used by the Commission in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment. Based on that review, the Department made specific recommendations regarding the assumptions to be used as inputs for the cash-flow model for farm methane projects.

The Department recommends changing several assumptions used in the cash flow models, including the assumptions addressing inflation, debt repayment reserves, working capital reserves, capital structure, depreciation expenses, rate of return, installation costs, and maintenance costs. In particular, the Department proposes the inclusion a debt repayment reserve and working capital reserve, similar to solar and wind projects. The Department recommends a capital structure that includes total debt that is 60% of financing starting at a rate of 4.0% for a term of 20 years. The Department proposes adjustments to the methodology for depreciating installation costs. The Department also proposes lowering the rate of return to 8.75%. For large farm methane projects, the Department recommends that installation costs be increased from $8,118 per kW to $8,500 per kW and maintenance costs be increased from approximately $350 per kW-year to $468 per kW-year. For small farm methane projects, the Department recommends that installation costs be decreased from $13,108 per kW to $11,100 per kW and maintenance costs be increased from approximately $350 per kW-year to $608 per kW-year.

AAFM suggests that large farm methane projects, with project costs over $2 million, may have higher financing costs because, at the larger capital requirement, Vermont Economic Development Authority ("VEDA") may no longer be available as a financing option. AAFM also suggests that some farm methane projects may not be eligible for grant funding through the Rural Energy for America Program ("REAP").

Ag-Grid recommends that the standard-offer price for farm methane projects be $0.205 per kWh. Ag-Grid argues that a price adjustment is needed because the federal ITC has expired for anaerobic digesters and because farms do not receive a tipping fee to accept liquid organic waste.

<u>Discussion</u>

In previous Commission proceedings, the Commission concluded that: (1) standard-offer prices should be based upon the assumption of efficiently sized and located generation to ensure that the price incentives are not excessive; and (2) the disaggregation of categories, with higher prices for smaller units, is inconsistent with this principle as it requires ratepayers to pay more without acquiring more renewable energy. However, in the case of farm methane projects, the Commission was persuaded that a price based on a smaller unit is appropriate because most of the farms that can host a 300-kW-sized project are already participating in the standard-offer program and because the establishment of a second price for smaller farms will allow for greater participation in the program.[35] I recommend that the Commission continue establishing separate prices for small and large farm methane projects.

The Department recommends several changes to the assumptions used to determine the 2017 farm methane avoided-cost prices of $0.145 per kWh and $0.199 per kWh. On balance, the Department's recommended assumptions result in the existing prices being relatively unchanged.

AAFM and Ag-Grid raise concerns about debt financing costs, ITC realization rates, and operating costs, but provide no project-specific information to challenge the accuracy of the Department's recommended assumptions. The Department has provided documented and reasonable assumptions from its expert, including those concerning debt financing costs, realization rates of the state and federal ITC, and operating costs. The Department's recommendations retain the existing assumptions on capital structure that includes total debt that is 60% of financing starting, but increases the debt financing rate from 3.75% to 4.0%. The Department's recommendations also assume REAP grants are available to farmers. The proposed financing assumptions allow a reasonable amount of flexibility in capital structures that should allow for a range of farmers to participate in the program, even if the financing rates and the availability of REAP grants do not apply to all farmers equally. The Department's assumptions on the state and federal ITC remain unchanged from 2017 and appropriately recognize that farm methane projects do not have the ability to claim these tax credits. With respect to operating costs, the Department's assumptions do not include revenues associated with tipping fees. Thus, Ag-Grid's request that the standard-offer price for farm methane projects be adjusted to $0.205 per kWh is unsupported.[36]

While the Department has proposed reasonable updates to the assumptions used in the cash-flow models, the Department's recommended assumptions do not reflect the recent tax law changes. As discussed above for other technology categories, the new tax code is reported to reduce the corporate tax rate and allows increased depreciation expenses, but it is unclear

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[35] *Order Re 2015 Standard-Offer Prices for Farm Methane Projects*, Dockets 7873 and 7874, Order of 4/2/15.
[36] Ag-Grid's comments do not recognize that farm methane projects include two price categories.

whether the changes to the handling of business losses will have any possible offset to these tax reductions. Without specific information on how the new tax code will be implemented, changing the assumptions in the cash-flow model addressing the corporate tax rate and depreciation expenses becomes an uncertain exercise at this time.

Recognizing the uncertainties related to the tax code changes, I recommend that the Commission not change the prices for small and large farm methane projects that were established in 2017. The Department's recommended assumptions, along with the tax code changes, will likely result in a prices that are lower than the 2017 values. However, as discussed above, it is difficult to implement the tax code changes at this time. It is also important that the established prices not discourage farm participation in the standard-offer program, especially given the concerns about technology diversity under the standard-offer program and the statutory directive to ensure sufficient incentive for rapid deployment.

Accordingly, for 2018 RFP, I recommend that the Commission establish an avoided cost of $0.145 per kWh for large farm methane projects, and an avoided cost of $0.199 per kWh for small farm methane projects, fixed over the life of the project.

VII. CONCLUSION

In this proposal for decision, I make several recommendations with regard to the implementation of the 2018 standard-offer program, including the allocation of available capacity under the program and the technology-specific avoided costs that will serve as price caps in the 2018 RFP.

With regard to the allocation of available capacity under the program, for use in the 2018 RFP, I recommend that the Commission establish a mechanism that includes a Provider Block and Developer Block. I also recommend that the Developer Block be further divided into a Price-Competitive Developer Block and a Technology Diversity Developer Block.

With regard to the technology-specific avoided costs, I recommend that the Commission establish the following avoided costs to serve as price caps for the 2018 RFP:

- Biomass -- $0.125 per kWh (levelized over 20 years)
- Landfill Gas -- 0.090 per kWh (levelized over 15 years)
- Wind > 100 kW -- $0.107 per kWh (fixed for 20 years)
- Wind ≤ 100 kW -- $0.258 per kWh (fixed for 20 years)

- New Hydroelectric -- $0.130 per kWh (fixed for 20 years)
- Food Waste Anaerobic Digestion -- $0.208 (fixed for 20 years)
- Solar -- $0.130 per kWh (fixed for 25 years)

Farm methane projects remain outside the standard-offer programmatic cap. I recommend that the Commission establish an avoided cost of $0.145 per kWh, fixed over the term of the 20-year contract, for large farm methane projects, and an avoided cost of $0.199 per kWh, fixed over the term of the 20-year contract, for small farm methane projects.

I recommend that the Commission direct the Standard Offer Facilitator to issue an RFP by April 1, 2018, consistent with the requirements of this Order and prior Orders in other standard-offer proceedings, to solicit standard-offer projects to meet the requirements of Section 8005a(c).

I am circulating this proposal for decision to the participants for their review and comment.

Dated at Montpelier, Vermont this 20th day of February, 2018

Mary Jo Krolewski

Mary Jo Krolewski
Hearing Officer

VIII. ORDER

IT IS HEREBY ORDERED, ADJUDGED, AND DECREED by the Public Utility Commission ("Commission") of the State of Vermont that:

1. The findings, conclusions, and recommendations of the Hearing Officer are adopted.

2. Pursuant to 30 V.S.A. § 8005a(c)(2), for 2018, the Commission establishes a mechanism for the allocation of available capacity under the standard-offer program as specified in this Order.

3. Effective for any standard-offer contract executed after March 1, 2018, the standard-offer prices for renewable power under 30 V.S.A. § 8005a(b)(2) shall be determined through a request for proposal issued by the Standard Offer Facilitator and shall be no higher than the avoided costs as specified in this Order.

4. Effective for any standard-offer contract executed after March 1, 2018, pursuant to 30 V.S.A. § 8005a(f)(2), the following avoided costs will serve as the prices for farm methane projects under the standard-offer program: (1) $0.145 per kWh fixed over the 20-year contract for projects with a nameplate capacity greater than 150 kW; and (2) $0.199 per kWh fixed over the 20-year contract for projects with a nameplate capacity less than or equal to 150 kW.

Dated at Montpelier, Vermont this ____________________________________

______________________________	)	
Anthony Z. Rosiman	)	PUBLIC UTILITY
	)	
	)	
______________________________	)	COMMISSION
Margaret Cheney	)	
	)	
	)	OF VERMONT
______________________________	)	
Sarah Hofmann	)	

OFFICE OF THE CLERK

Filed:

Attest:___________________________
Clerk of the Commission

Notice to Readers: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Commission (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: puc.clerk@vermont.gov)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Commission within thirty days. Appeal will not stay the effect of this Order, absent further order by this Commission or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Commission within 28 days of the date of this decision and Order.