STATE OF VERMONT
BEFORE THE
PUBLIC UTILITY COMMISSION

Investigation to review the 2021 implementation of the standard-offer program	)))	**Case No. 20-2935-INV**

OPENING COMMENTS OF ALLCO RENEWABLE ENERGY LIMITED AND ALLCO FINANCE LIMITED

Allco Renewable Energy Limited and Allco Finance Limited (collectively, "Allco") respectfully submit the following comments and evidence in response to the Order dated October 9, 2020 (the "Order") of the Public Utility Commission ("Commission").

I. The Market-Based Mechanism Employed By The Commission Is Inconsistent With PURPA Both Before And After The FERC's New Final Rule.

The market-based mechanism for the Standard Offer cycle is not consistent with federal law. The Federal Power Act delegated to the Federal Power Commission, now the Federal Energy Regulatory Commission ("FERC") "exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce, without regard to the source of production." *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982). That straightforward and unambiguous statutory delegation is found in the first sentence of FPA section 201(b)(1). *FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215 (1964) (Congress left "no power in the states to regulate … sales for resale in interstate commerce."). Compelling a wholesale transaction – one that would not have taken place but for the State's compulsion – such as under the Vermont Standard Offer program plainly involves the regulation of wholesale sales, and thus falls squarely within the field that Congress has occupied.[1] *See also, Allco II* at 91 (2d. Cir. 2015) ("States may not act in [wholesale sale of electricity] this area unless Congress creates an exception. *Id.* § 824(b).") Congress created such an exception with Section 210 of PURPA. Thus, in order for the Standard Offer program's compulsion of wholesale sales to be valid, the price must meet PURPA's requirements, which must be at the ratepayer-neutral price of the utility's avoided costs. 18 C.F.R. §292.303.

In *California Pub. Utils. Comm'n*, 132 FERC P61,047 (2010) at ¶64, the FERC restated those principles as applied to wholesale sales of electricity:

> The Commission's authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce by public utilities. [*citing* 16 U.S.C. §§ 824, 824d, 824e; *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988)]. While Congress has authorized a role for States in setting wholesale rates under PURPA, *Congress has not authorized other opportunities for States to set rates for wholesale sales in interstate commerce by public utilities, or indicated that the Commission's actions or inactions can give States this authority*. . . . .

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[1] The Standard Offer contracts at issue in this case are FERC-jurisdictional wholesale sale contracts. *See, e.g., PJM Interconnection, LLC*, 123 FERC ¶ 61,087 (2008). Under each Standard Offer contract, the generator facility sells energy to VEPP who then re-sells it and wheels it to different Vermont utilities. The Vermont standard offer contracts are not *intra*-state commerce sales contracts. *See also*, *New York v. FERC*, 535 U.S. 1 (2002). Noting that electrons travel at the speed of light of 186,000 miles per second, the United States Supreme Court stated that there are only three areas of the United States where sales are not interstate—Alaska, Hawaii and most of Texas. *Id*. at 5:

> electricity is now delivered over three major networks, or "grids" in the continental United States. Two of these grids -- the "Eastern Interconnect" and the "Western Interconnect" -- are connected to each other. It is only in Hawaii and Alaska and on the "Texas Interconnect" -- which covers most of that State -- that electricity is distributed entirely within a single State. In the rest of the country, any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce**.**

(Emphasis added.)

Because a State's *only* authority to regulate wholesale electricity sales is derived from PURPA, any state rule that conflicts with those requirements is necessarily preempted.

A. The Market-Based Mechanism Employed By The Commission Is Inconsistent With The FERC's New Final Rule.

The FERC amended its regulations under the Public Utility Regulatory Policies Act ("PURPA") regulations in Order No. 872, 172 FERC ¶ 61,041 (2020). Under FERC's new PURPA rule, Order No. 872, the market-based mechanism fails to pass muster. As explained in Order No. 872 starting at paragraph 411, a competitive solicitation, i.e., a request for price proposals, such as the market-based mechanism, can only be used to set pricing if it satisfies certain minimum criteria. Those criteria include, among others, *see* Order No. 872 at ¶413:

> (a) an open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility.

To comply with the new PURPA rule a procurement must be conducted in a nondiscriminatory manner (i.e., no set-aside blocks such as Vermont's standard offer provider block), and open for bidding to <u>*all sources*</u>, including QF and non-QF resources, on a level playing field. *See,* Order No. 872 at ¶411, 413:

> 411. In this final rule, we affirm the NOPR proposal to revise the PURPA Regulations to explicitly permit a state the flexibility to set avoided energy and/or capacity rates using competitive solicitations (i.e., RFPs), conducted pursuant to appropriate procedures in a transparent and non-discriminatory manner. A primary feature of a transparent and non-discriminatory competitive solicitation is that a utility's capacity needs are open for bidding to all capacity providers, including QF and non-QF resources, on a level playing field. This level playing field ensures that any QF's capacity rates that result from the competitive solicitation are just and reasonable and non-discriminatory avoided cost rates.
>
> …

> 413. In considering what constitutes proper design and administration of a competitive solicitation, however, we find it appropriate to establish certain minimum criteria governing the process by which competitive solicitations are to be conducted in order for an competitive solicitation to be used to set QF rates. These factors, which we proposed in the NOPR and adopt here, include, among others: (a) an open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility.

At ¶433 of Order No. 872, the FERC clarifies that the phrase "taking into account the operating characteristics of the needed capacity," *cannot* be used to favor QF renewables. The market-based mechanism does not meet FERC's criteria. Moreover, the Vermont statute prohibits participation by gas plants.

The FERC's new rule does not alter the ability of the Commission to set standard rates, such as the 13 cents per KWH for solar that the Commission has determined over the past few years that represent avoided costs for solar. *See, e.g.*, Order 872-A, 173 FERC ¶ 61,158 (November 19, 2020), ¶ 226 ("We believe that a fairly administered competitive solicitation is a more accurate reflection of a purchasing electric utility's avoided energy and capacity costs. Moreover, in addition to the requirement to provide standard rates for QFs 100 kW and below, states already have discretion to set that standard rate threshold above 100 kW.")

The FERC's new rule also makes it clear that if the market-based mechanism is used, then the provider block cannot separately exist and all projects must compete on a level playing field. The FERC's new rule also does not alter the prohibition of caps on the amount of capacity of contracts, unless the utilities have no more capacity needs in the future, which is not the case in Vermont.

B. The Market-Based Mechanism Employed By The Commission Is Inconsistent With The FERC's Existing Regulations.

Even under FERC's current regulations, the market-based bidding mechanism employed is just as infirm as the market-based bidding mechanism held unlawful by the Ninth Circuit in *Winding Creek Solar LLC v. Peterman*, 932 F.3d 861 (9th Cir. 2019) ("*Winding Creek*"). A straight-forward logic exercise proves that the reverse auction mechanism is inconsistent with PURPA. Under PURPA, it is TRUE that there can be no cap on the "must-take" obligation. All energy offered and made available by a QF must be contracted for. *Winding Creek* at 865. But the reverse auction mechanism requires that proposition to be FALSE. That is because the reverse auction *only* serves its intended purpose (*i.e*., setting a price below avoided costs) if capacity is capped or limited, thus forcing QFs to compete against each other. If there can be no cap as *Winding Creek* confirms, then the reverse auction does not, and cannot, function because QFs are not required to compete, resulting in all QFs bidding at the ratepayer-neutral avoided cost price determined by the Commission. Moreover, the Vermont Standard Offer market-based mechanism (even under FERC's existing rule) does not comply with PURPA because the price it offers is not based on the costs *the utility* would incur but for its purchase from QFs. Instead, the Vermont Standard Offer market-based mechanism price is based on the price at which QFs are willing to sell, which is the same type of market-based mechanism invalidated by the Ninth Circuit in *Winding Creek*. As *Winding Creek* plainly shows, the reverse auction pricing scheme is fundamentally based upon *ignoring* the "must take" obligation. If two QFs offer all their energy, the utilities must-take all the energy made available from *both* QFs. But the reverse auction ignores that rule by saying the utility is only buying from one QF. Without ignoring the foundational must-take obligation, the reverse auction would be ineffectual, plainly showing its inconsistency with federal law.[2]

II. The Existing Avoided Cost Determinations Continue To Be Valid And Should Be Used As The Pricing For The 2021 Standard Offer Program.

The existing avoided cost determinations continue to be valid, which is 13 cents per kwh for solar. While variables used by the Department of Public Service in prior years have changed in different directions, the largest change is the continuing decline is in the federal investment tax credit. The existing avoided cost price of 13 cents per kwh for solar is also supported by the attached Synapse report and the prior year comments and analysis of the Department of Public Service. Attached are the following exhibits:

Exhibit A- Synapse Report

Exhibit B- Department of Public Service recommendations on avoided cost price caps for the 2020 standard offer program

Exhibit C-Recommendations of the Department of Public Service on avoided cost price caps for the 2019 standard offer program solicitation

Exhibit D-Recommendations of the Department of Public Service on capacity allocations and avoided cost price caps for the 2018 standard offer program solicitation

Exhibit E-Department of Public Service Recommendations for Input Assumptions to Calculation of Standard Offer Bid Price Caps (November 20, 2017)

Respectfully submitted,

/s/Thomas Melone
Thomas Melone

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[2] It is no answer to claim that the Vermont market-based mechanism reflects the costs that a utility avoids by purchasing from one QF instead of another QF. That is so for two reasons. *First,* FERC has defined "avoided costs" to mean the costs the utility would incur "but for the purchase from the qualifying facility *or qualifying facilities*." 18 C.F.R. §292.101(b)(6) (emphasis added). That "but for" price is the costs of buying from a *non-QF* or the cost of building the facility itself. *Second*, a utility is not permitted to avoid purchasing electricity from a QF. *Winding Creek* at 865. It makes no sense to define the utility's *avoided* costs in reference to the costs of purchasing electricity from another QF, when the utility is required to purchase from that QF too.

Bar No. 5456
Allco Renewable Energy Limited
157 Church St., 15th floor
New Haven, CT 06510
Phone: (212) 681-1120
Email: Thomas.Melone@AllcoUS.com

Dated: December 11, 2020

EXHIBIT A

Solar Savings in New England

From 2014 to 2019, small-scale solar in New England produced wholesale energy market benefits of $1.1 billion

December 2020

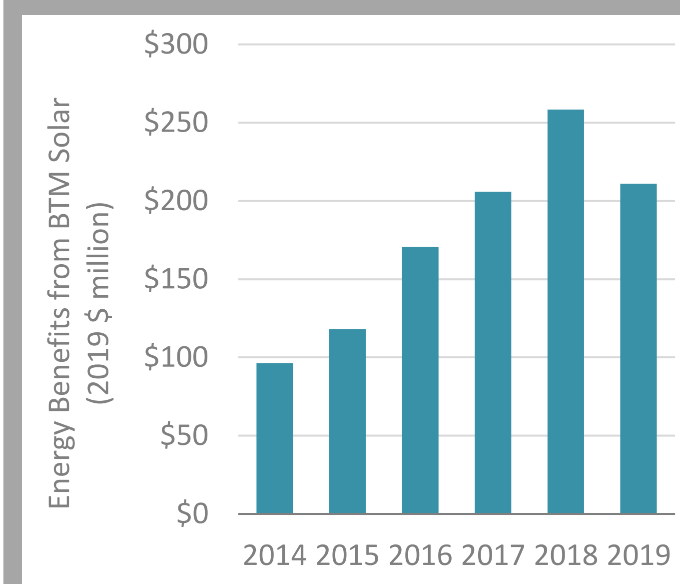
Between 2014 and 2019, behind-the-meter (BTM) solar produced more than 8,600 gigawatt-hours (GWh) of electricity in the six New England states. Electricity produced from BTM solar reduces the need to run other power plants, which reduces the amount of electricity that electric utilities need to buy and saves customers money. By avoiding the need to run the most expensive power plant, when BTM solar lowers the amount of electricity purchased, it also reduces the price that all utilities pay. Here, BTM solar is defined as small solar installations that do not participate in New England's energy markets (for more information see page 7).

Using hourly BTM solar data published in July 2020 by ISO New England, the nonprofit regional electric grid operator, Synapse estimated what demand and prices for electricity would have been without this resource.[1] We analyzed over 52,500 hourly datapoints from 2014 to 2019, and estimated that BTM solar reduced wholesale energy market costs in New England by $1.1 billion (see Figure 1). These include benefits that are shared by electricity customers throughout New England, not just the owners of the BTM solar facilities. Of this total, we estimate that benefits from price effects represent $743 million or 70 percent of the total. When the total benefits are divided by the quantity of electricity produced, we find the energy impact of BTM solar is 11.9 cents per kWh over this six-year period.

Hourly electricity benefits are just one benefit BTM solar can provide. Hourly analysis of this dataset using peer-reviewed tools published by the U.S. Environmental Protection Agency (U.S. EPA) shows that BTM solar avoided 4.6 million metric tons of climate-damaging carbon dioxide emissions in 2014 through 2019, and avoided millions of pounds of criteria pollutants proven to have negative impacts on human health. As a result, BTM solar contributed to $87 million in public health benefits in 2014 through 2019 (equal to 1.0 cents per kWh). Likewise, using a $112 per metric ton social cost of carbon, BTM solar provided $515 million dollars in climate benefits in 2014–2019 (equal to 6.0 cents per kWh).

BTM solar also provides other benefits, including reduced costs for generating capacity, transmission and distribution capacity, reliability, and retail margins. It also provides other economic benefits, such as job creation, local tax base support, and participant cost savings. All of these benefits should be considered when looking at a full societal value of BTM solar.

Figure 1. Energy benefits from BTM solar



Notes: 2018, a year with numerous heat waves and especially high summertime energy prices, has a particularly large amount of savings. Benefits described in this figure only include impacts related to the wholesale energy market. Other benefits (e.g., public health, climate, capacity, transmission and distribution, reliability, or retail margins) are not included.

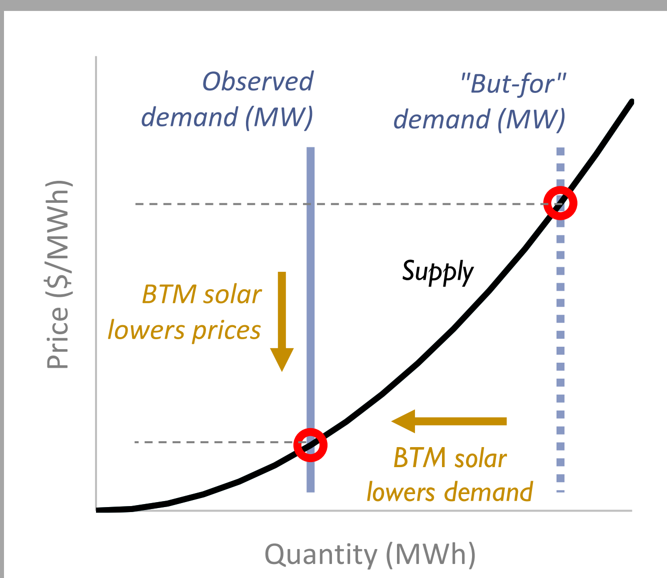
Synapse Energy Economics, Inc.

Authors: Patrick Knight, Steve Letendre, PhD, and Erin Camp, PhD

Methodology

When BTM solar produces electricity, electric utilities—and ultimately electric ratepayers—will purchase fewer kWh of electricity from other sources (e.g., fossil fuel-fired power plants). As BTM solar output increases, consumers pay less for electricity because the quantity of electricity purchased from other sources decreases. In addition, BTM solar has a second effect on electricity costs: because it reduces the demand for electricity to be purchased from other sources, it avoids the need to buy power from the most expensive power plant. This leads to a lower "market clearing price" that is paid to all electric generators on the grid (see Figure 2). As a result, more BTM solar not only decreases the quantity of electricity purchased, it also reduces the price paid for purchased electricity—which benefits all New England ratepayers .

Figure 2. Illustrative price and load impacts of BTM solar



In July 2020, for the first time, ISO New England published regionwide, hourly estimates of BTM solar generation for January 2014 through April 2020. This dataset is based on a sampling of hourly, actual solar output from individual facilities throughout New England, which are then upscaled to estimate aggregated solar production by state. After this data was posted on the ISO New England web site, Synapse deployed the "but-for" methodology (see callout) for each week from 2014 through 2019.[2]

Predictive Equations: Step-by-Step

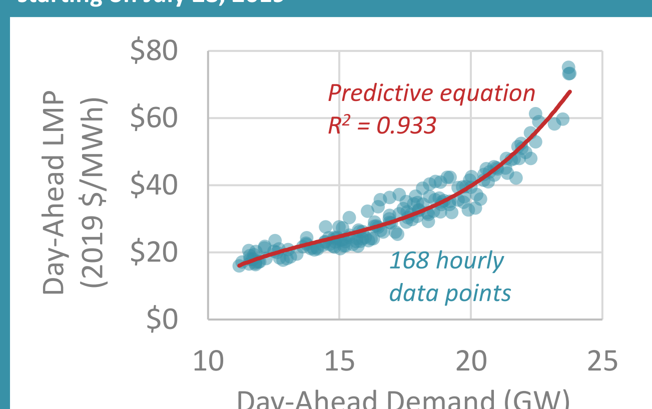
First, we assembled hourly, day-ahead price and demand data for 2014 through 2019.[3] We grouped hours into weeklong periods (Sunday through Saturday), and performed a regression for each individual week with demand as an independent variable and prices as a dependent variable. This regression provides a predictive equation of wholesale electricity price for any hourly demand in this week. For each hour, demand (measured in MW) and prices (measured in dollars per MWh) can be multiplied to calculate the total energy costs in that hour (measured in dollars).

Second, we assembled hourly BTM solar data. Each hourly datapoint was increased by 6 percent to reflect average transmission and distribution losses, then added to the demand in each hour. This provides an estimate of what demand would have been, if not for BTM solar.

Third, we used the predictive equations calculated in (1) to estimate what hourly prices would have been, if not for the BTM solar generation, all else being equal. As in (1), we can multiply the "but-for" demand by the resulting "but for" prices to estimate the total energy costs in each hour in the "but-for" hypothetical.

Fourth, we subtracted the total costs from the "but-for" costs to estimate the energy benefits resulting from BTM solar generation.

Figure 3. Illustrative predictive equation for week starting on July 28, 2019



Calculating energy benefits

For each week, we calculated the hourly total costs for each 24-hour period (24 hours x 313 weeks, producing costs for 7,512 hours) using week-specific predictive equations. Over the six-year period, the weekly predictive equations estimate total wholesale energy costs of $33.0 billion in 2019 dollars.

We then added the BTM solar output from ISO New England to each hour. Using each week-specific prediction equation, we calculated what energy costs would have been if not for BTM solar. Without BTM solar, we find that total wholesale market costs would have been $34.2 billion, suggesting that total benefits from solar are approximately 1.2 billion.

However, not all predictive equations are equally successful at estimating benefits. In some winter weeks, for example, energy market prices are more closely linked to fuel prices rather than demand for electricity. In these weeks, although BTM solar continues to reduce the demand for electricity produced from other sources, it is less able to reduce electricity costs.

To account for this, we examine two different time periods: summer weeks (any weeks in 2014 through 2019 that have at least one day in May, June, July, August, and September) and non-summer weeks (all other weeks). Summer weeks contain 43 percent of the total weeks analyzed, but 57 percent of the BTM solar produced. Predictive equations in summer weeks are generally very accurate. In 98 percent of summer weeks, estimated electricity prices are within 10 percent of the actual price. Meanwhile, non-summer weeks generally feature less successful predictive equations: only 83 percent of non-summer weeks estimate electricity prices within 10 percent of actuals.

For this analysis, we remove any weeks where the predictive equations are unable to accurately estimate prices within 10 percent, on average over the entire week. As a result, we estimate energy benefits of $1.1 billion, rather than $1.2 billion (a reduction of 10 percent). In reality, there is some non-zero quantity of energy benefits in these weeks because the BTM solar avoids the need for utilities to purchase energy from the wholesale markets. Thus, this is a conservative, lower-bound estimate as we only include those weeks with high predictive capabilities.

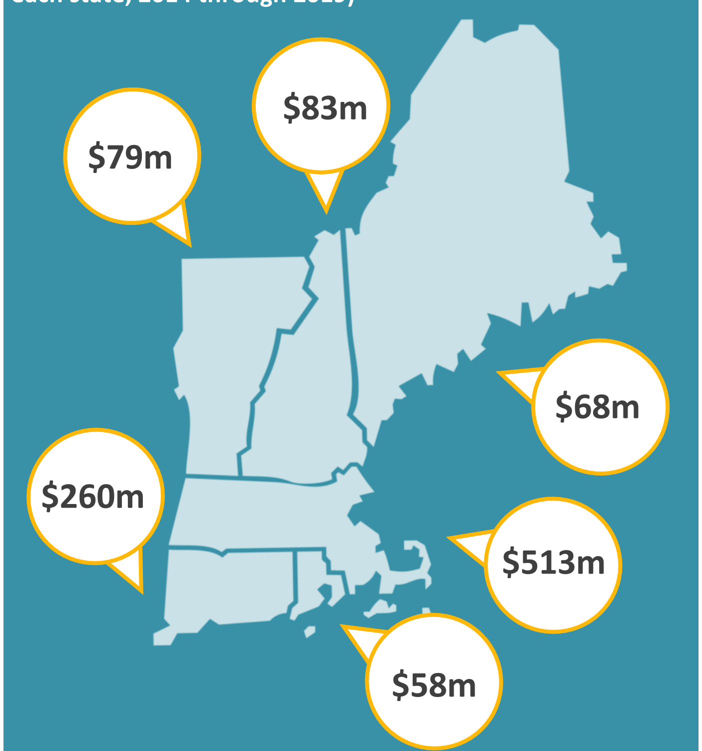
Load impacts and price impacts

The calculated energy benefits can be split into "load impacts" and "price impacts." Load impacts refer to the benefits associated with the reduction in the quantity of electricity purchased. "Price impacts" are due to the impact of reduced demand on the market-clearing price of electricity, as shown previously in Figure 2.

For each week, load impacts can be calculated by estimating energy benefits where demand is increased by the hourly BTM solar quantity but where prices are unchanged. The "price impact" can be estimated by subtracting the "load impact" from the total benefits. Over the six years analyzed, we find that load impacts provide about $317 million in benefits (30 percent of the total) while price impacts provide about $743 million in benefits (70 percent of the total). This only includes benefits for those weeks "screened into" our analysis.

To understand how each impact could be allocated to each state, we assume that load impacts are distributed across the six New England states based on each state's contribution to BTM solar production. In other words, states with more installed BTM solar accrue a greater share of the load impact.[4] Meanwhile, as shown in Figure 4's depiction of the total impacts for each state, we

Figure 4. Total energy savings from BTM solar accrued in each state, 2014 through 2019)



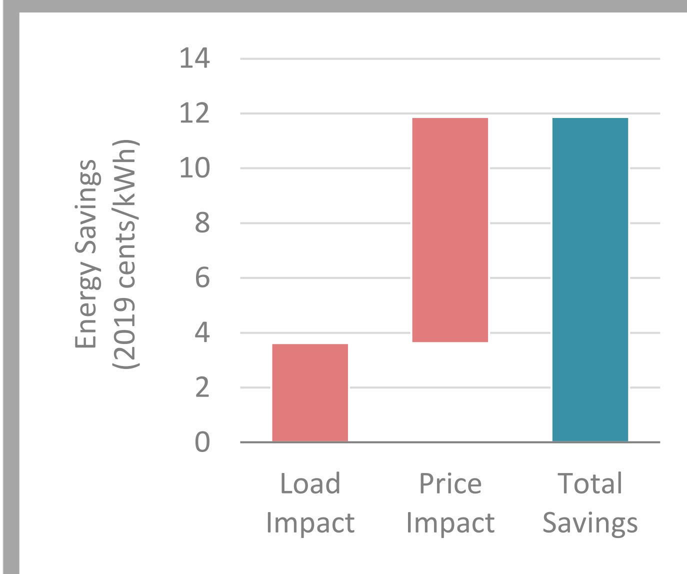
assume that the price impacts are distributed across the six New England states based on each state's contribution to observed day-ahead demand. In other words, states with larger electricity demand accrue a greater share of the price impact, and states with larger quantities of installed BTM solar accrue a greater share of the load impact.

Value per kWh

These energy benefits can be divided by the quantity of solar produced in each year to estimate the price impact value and the load impact value of BTM solar in cents-per-kWh terms. However, if each annual value is calculated using only the "screened-in" weeks, it will overestimate the cents-per-kWh benefits in weeks with poor predictive equations. In order to account for this, we multiply the cents-per-kWh value by the percentage of weeks that "screen in" for each year, thereby assuming the cents-per-kWh value in "screened out" weeks is 0 cents per kWh. We perform this operation separately for summer and non-summer weeks, which we then combine using an average weighted by the total number of all weeks in each seasonal period.

Figure 5 displays the resulting values for both load and price impacts in each year of the analysis. Because load impacts per kWh describe the benefits associated with reducing quantities, but not prices, they resemble average prices observed during the summer weeks. On average, over the six years analyzed, BTM solar provided a total value-per-kWh wholesale market benefit equal to 11.9 cents per kWh.

Figure 5. Energy benefits per kWh of BTM solar



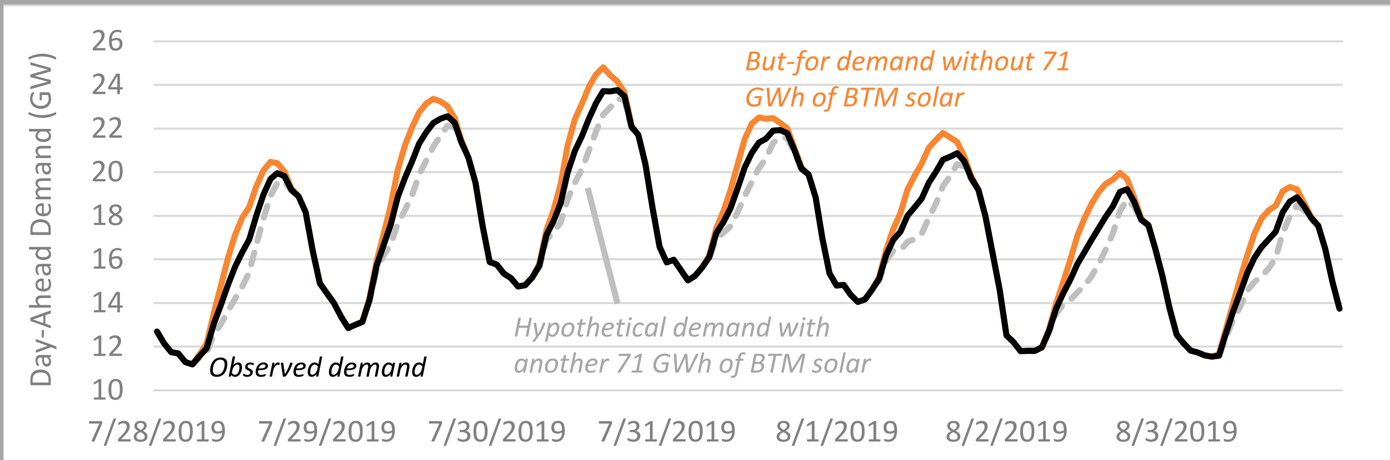
This value may vary week-to-week and year-to-year. For example, during hot years, total demand for electricity increases. This increase in demand often leads to increased prices, meaning that solar resources can avoid purchasing more energy at higher prices than in other years. 2018 in particular featured three separate heat waves, which contributed to a quantity of heating degree days that were 19 percent higher than the 2014-2019 average. This led to a year with summertime energy prices 11 percent higher than average.

Impact of increasing levels of BTM solar

Output from fixed solar facilities typically peaks around noon and decreases later in the day when demand for electricity remains high. This fact leads some to argue that as more BTM solar is installed, fewer energy benefits will accrue. Because energy prices are closely linked with demand in most summer weeks, as more solar comes online, it may increasingly reduce prices that are not necessarily the highest prices. Nonetheless, with the amount of BTM solar on the grid now, or expected in the next several years, prices at times of peak solar output are still likely to be high. Conversely, at times of high prices (e.g., later in the afternoon) systemwide BTM solar output may be reduced but not outright eliminated. As a result, additional BTM solar may provide fewer wholesale market cost benefits, but some benefits still remain.

To assess this issue, we examined one week in July 2019 with a total BTM solar output of 71 GWh. Figure 6 on the next page shows the observed hourly demand for this week in black, and the "but-for" demand in yellow. This figure also features a second hypothetical series in grey that posits what demand would have been with double the amount of BTM solar power. In our "but-for" analysis described above, the first 71 GWh of BTM solar provided \$10.7 million in energy benefits. Doubling the amount of solar provides energy benefits of \$19.1 million. In other words, doubling the quantity of solar would increase benefits by 80 percent.

Figure 6. Demand for illustrative week, with and without BTM solar



Note: Y-axis begins at 10 GW in order to highlight the difference between the three depicted scenarios.

This phenomenon often triggers discussions of conventional resources' capability to quickly ramp up or down to accommodate changes in solar output during the evening and morning hours, respectively. In this example week, the largest hourly change (a reduction of 2,082 MW) occurs between the hours of midnight and 1AM when solar is not operating in any circumstance. In hours when BTM solar is operating, additional BTM solar actually *reduces* the maximum hour-to-hour MW change, which occurs as demand is increasing between 7AM and 8AM (thereby likely making the morning ramp easier). Of all 112 hours in this week when BTM solar is operating, only 35 feature hourly changes that are greater after adding an additional 71 GWh of BTM solar . In these 35 hours, the maximum increase in hourly changes is 386 MW. This is equal to 2 percent of the day-ahead demand observed in that hour, or, about one-fifth the maximum hourly change observed (2,082 MW).

As discussed above, savings depend not only on how much BTM solar is installed, but also on other underlying system drivers. For example, temperatures were lower in 2019 than in 2018, leading to fewer periods of high summer prices. One way to examine these impacts is to model the 2019 quantity of solar on the weather and resulting energy prices that were observed in 2018. We find that total savings would have been $317 million, rather than $211 million, an increase of 50 percent.

Emissions and public health impacts

We used publicly available tools to evaluate the impact that BTM solar has on emissions and public health. First, we used the Avoided geneRation and Emissions Tool (AVERT) from the U.S. EPA. AVERT relies on actual, hourly, power plant-specific data published by U.S. EPA to statistically estimate the marginal emissions and generation avoided by renewable energy and energy efficiency.[5] According to AVERT, if the hourly output from BTM solar reported by ISO New England did not exist, 4.6 million metric tons of climate-damaging carbon dioxide would have been emitted from 2014 to 2019 (see Table 1). In addition, BTM solar avoided the release of hundreds of thousands of pounds of criteria pollutants proven to have negative impacts on human health. According to AVERT, in 2019, 94 percent of the generation avoided came from natural gas-fired power plants, while an additional 6 percent came from power plants fueled by oil, coal, or other resources.

Table 1. Estimated emissions avoided by BTM solar

Pollutant	Avoided emissions
Greenhouse gases (reported in million metric tons)	
Carbon dioxide (CO_2)	4.6
Criteria pollutants (reported in pounds)	
Sulfur dioxide (SO_2)	2,380,000
Nitrogen oxides (NO_X)	3,280,000
Particulate matter ($PM_{2.5}$)	340,000

Note: Avoided emissions for each pollutant are reported in the unit that is most commonly used for data reporting and other analysis. These emission benefits are calculated for all hours in 2014 through 2019, rather than only the weeks that met our screening criteria for energy benefits.

We then used these results in U.S. EPA's CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool. COBRA uses a reduced form air quality model to estimate how criteria pollutants like sulfur dioxide (SO2), nitrogen oxides (NOX), and particulate matter (PM2.5) are transported through the atmosphere. COBRA then relies on assembled data from the literature to estimate how these pollutants impact different populations on a county-by-county level, and it translates any decreases of these pollutants into monetized public health benefits.[6] According to COBRA, the BTM solar estimated by ISO New England in 2014 through 2019 contributed to $87 million in public health benefits (see Table 2). Dividing this cost by the solar produced in this time period yields a health benefit of 1.0 cents per kWh. We also examined the benefits of reducing greenhouse gas emissions across a range of social costs of carbon. Depending on the cost of carbon modeled in this analysis, benefits from 2014 to 2019 are as high as $1.9 billion dollars. This translates into 22.6 cents per kWh of BTM solar.[7]

Table 2. Monetized benefits from improved public health and social cost of carbon

Pollutant	2019 $ M	2019 cents / kWh
Climate benefits from reduced greenhouse gas emissions		
At $112/MT	$515	6.0 ¢
At 200/MT	$918	10.7 ¢
At $425/MT	$1,948	22.6 ¢
Public health benefits from reduced criteria pollutants		
SO_2, NO_X, and $PM_{2.5}$	$87	1.0 ¢

Note: A price of $112 per metric ton corresponds to the $100 per short ton price approved by the VT PUC in Case No. 19-0397-PET. Other prices illustrate the carbon benefits of solar at higher prices. These public health benefits are calculated for all hours in 2014 through 2019, rather than only the weeks that met our screening criteria for energy benefits. See footnote 6 for additional information.

Other avoided costs

In addition to the energy benefits and public health impacts described above, BTM solar can provide other benefits. Increased quantities of BTM solar reduce the demand for grid-level capacity that must be purchased through ISO New England's Forward Capacity Market (FCM). Lowering the demand for capacity reduces capacity costs, thus reducing the overall electricity costs paid by ratepayers throughout New England. For example, we estimate that the value of capacity for solar installed in 2019 was $1.75 per kilowatt-month, or about 1.6 cents per kWh.[8]

As with the energy market, costs and prices in the FCM are calculated through supply and demand curves. This means that, as in the energy market, there is the potential for BTM solar to not only reduce the quantity of capacity purchased, but to also decrease the clearing price paid for capacity. BTM solar can also reduce other costs such as transmission and distribution capacity, reliability, and retail margins (i.e., the markup on costs observed between retail and wholesale prices that in some cases may represent utility profit). Finally, BTM solar provides other benefits to states or individual customers, including job creation, local tax base support, and participant cost savings. All of these benefits would reasonably be considered when looking at a full societal value of BTM solar.

How do energy benefits get passed to ratepayers?

Energy and capacity benefits are passed to ratepayers by load-serving entities (LSE) such as distribution utilities that purchase electricity at the wholesale level. The benefits described in this analysis are calculated for the day-ahead energy market. However, most, if not all, LSEs use out-of-market contracts to hedge their purchase of energy from the day-ahead market, which effectively acts a spot market.[9]

Each LSE may sign many different contracts with different suppliers for different quantities. Contract terms may overlap and contract terms can last weeks or years. Because the day-ahead market represents what the market is willing to pay for electricity on a spot basis, the expectation of future day-ahead market prices can be viewed as a proxy for the price of electricity paid in bilateral contracts. As such, while any one entity may not garner the exact savings from BTM solar estimated in this analysis, lower costs for electricity purchased in the day-ahead market should translate into lower contract costs, and eventually, lower costs paid by ratepayers.

Other caveats

The energy benefits described in this document only cover the solar quantity that ISO New England describes as "BTM solar." BTM solar is defined as the output from small (i.e., less than 5 MW), distributed systems that do not participate in the energy markets.[10] The dataset of hourly BTM solar production provided by ISO New England does not include any output from facilities that have a commitment in the Forward Capacity Market (FCM) or facilities that may have load co-located behind the meter but participate in the energy market. The benefits described in this document would likely be higher were output from these power plants also included. The quantity of solar that is BTM solar versus other some other type is different in each state. In Vermont, ISO New England defines virtually all of the installed solar capacity as BTM solar, while in Rhode Island and parts of Massachusetts, BTM solar, as defined by ISO New England, represents just one-third to one-half of the total solar installed capacity.[11] Hourly dispatch from these plants is estimated by "upscaling" the output from a subset of solar facilities throughout New England; actual production from BTM solar facilities may differ from the hourly estimates provided by ISO New England.

This analysis does not take into consideration how the electric grid might have otherwise been different if not for solar.

Summary of impacts

Table 3 shows a summary of the solar benefits assessed in this study. These categories of benefits should be carefully weighed against costs of solar to estimate the full benefit-cost ratio of solar policies.

Table 3. Summary of historical BTM solar benefits (2019 cents per kWh)

Benefit category	High	Medium	Low
Energy	11.9 ¢	11.9 ¢	11.9 ¢
Capacity	1.6 ¢	1.6 ¢	1.6 ¢
Criteria pollutants (SO_2, NO_X, $PM_{2.5}$)	1.0 ¢	1.0 ¢	1.0 ¢
CO_2 @ $425/MT	22.6 ¢	-	-
CO_2 @ $200/MT	-	10.7 ¢	-
CO_2 @ $112/MT	-	-	6.0 ¢
Energy, capacity, and pollution reduction benefits of BTM solar	**37.1 ¢**	**25.2 ¢**	**20.5 ¢**

Additional benefits not calculated:

- Capacity price impacts
- Transmission and distribution capacity
- Local economic benefits
- Local tax support
- Reliability benefits
- Participant savings
- Retail margin

Endnotes and Sources

1. See hourly BTM solar data published by ISO New England on July 24, 2020 at www.iso-ne.com/static-assets/documents/2020/07/btm_pv_data.xlsx. Further documentation is available at https://www.iso-ne.com/static-assets/documents/2020/07/btm_pv_data_documentation.pdf.

2. Synapse explored a variety of other regression types and found that third-order polynomials remain the regressions that best explain the relationship between electricity demand and prices .

3. Hourly data on prices and loads is available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info. This analysis focuses on day-ahead demand and day-ahead locational marginal prices (LMP).

4. Load impacts from net-metered solar facilities are most appropriately allocated to their owners, while load impacts from standalone solar facilities can be allocated to the entire state.

5. See https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert for more information on AVERT.

6. See https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool for more information on COBRA.

7. A $112 per metric ton price (in 2019 dollars) corresponds to the $100 per short ton price (in 2018 dollars) approved by the Vermont Public Utility Commission in Case No. 19-0397-PET (order available at https://epsb.vermont.gov/?q=downloadfile/417666/138298). A $200 per metric ton value is in line with the value described in Hänsel, M.C., Drupp, M.A., Johansson, D.J.A. et al. Climate economics support for the UN climate targets. Nat. Clim. Chang. 10, 781–789 (2020). https://doi.org/10.1038/s41558-020-0833-x. A $425 per metric ton value is in line with the value described in Ricke, K., Drouet, L., Caldeira, K. et al. Country-level social cost of carbon. Nat. Clim. Chang. 8, 895–900 (2018). https://doi.org/10.1038/s41558-018-0282-y.

8. Calculated by adjusting the average avoided capacity price for FCA 9 and 10 (listed in AESC 2018, Table 39, available at https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf) to reflect peak line losses of 8 percent and a capacity credit of 19 percent (per slide 14 at https://www.iso-ne.com/static-assets/documents/2020/09/a6_a_iii_cea_mottmacdonald_presentation_cone_and_ortp.pptx) to derive $1.75 per kilowatt-month. This value was then multiplied by the peak BTM solar output in New England in 2019 (1.8 GW), then divided by the total BTM solar output reported by ISO New England (2.3 TWh). This estimation does not include the value of solar for future years (i.e., after December 2019), retail margin impacts, or capacity price suppression effects.

9. A separate real-time spot market exists to balance the differences between day-ahead demand (and supply commitments) with actual supply and demand requirements. Per ISO New England's September 2020 COO report (see https://www.iso-ne.com/static-assets/documents/2020/09/september-2020-coo-report.pdf, page 47), day-ahead demand represented 95 to 99 percent of actual, real-time demand between August 2019 and August 2020. The exact makeup of electricity power purchases (long-term contracts, day-ahead purchases, or real-time purchases) by New England LSEs is unavailable, as it represents a collection of private-party bilateral contracts and business practices. However, conversations between Synapse analysts and LSE representatives over the past two decades suggests that in general, roughly 60 percent of wholesale energy market purchases are hedged through bilateral agreements, with the remaining 40 percent purchased outright from the spot market (35 percent day-ahead, and 5 percent real-time). These rough percentages vary from LSE to LSE, and also vary over time.

10. Despite being called "BTM," this dataset does not necessarily exclude small, distributed systems that are physically installed in front of a meter.

11. See https://www.iso-ne.com/static-assets/documents/2020/07/btm_pv_data_documentation.pdf, page 8

About Synapse Energy Economics

Synapse Energy Economics, Inc. is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

For more information, contact: Pat Knight, Principal Associate pknight@synapse-energy.com | 617-453-7051

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Since 2002, Vote Solar has been working to make solar affordable and accessible to more Americans. Vote Solar works at the state level all across the country to support the policies and programs needed to repower our grid with clean energy. Vote Solar is proud to be nonpartisan, neither supporting nor opposing candidates or political parties at any level of government, but always working to expand access to clean solar energy. www.votesolar.org

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Clean Energy NH is the Granite State's leading clean energy advocate and educator, dedicated to promoting clean energy and technologies that strengthen the economy, protect public health, and conserve natural resources. Clean Energy NH builds relationships among people and organizations using a fact-based approach that offers objective, balanced, and practical insights for transforming NH's clean energy economy and sustaining its citizens' way of life. www.cleanenergynh.org

EXHIBIT B

This document has been electronically filed using ePUC.

STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 19-4466-INV

Investigation to review the avoided costs that serve as prices for the standard-offer program in 2020	

DEPARTMENT OF PUBLIC SERVICE RECOMMENDATIONS ON AVOIDED COST PRICE CAPS FOR THE 2020 STANDARD OFFER PROGRAM

Introduction

On November 7, 2019, the Public Utility Commission ("PUC") opened an investigation to review the avoided costs that serve as price caps for the standard-offer program in 2020. The 2020 request for proposal ("RFP") will retain the technology allocation used in the 2019 RFP. The PUC requests parties submit comments and recommendations on avoided-cost prices for the 2020 solicitation. The Department of Public Service ("Department") recommends retaining the current standard-offer price caps for the 2020 RFP. However, the Department also recommends adjusting how these price caps are applied to the Provider Block.

Price Cap Recommendations

The Department recommends maintaining the standard-offer price caps that were used in the 2019 RFP for the 2020 RFP. The existing price caps, by technology are:

Technology	**Price per kWh**	**Term**
Biomass	$0.125	Levelized over 20 years
Landfill Gas	$0.090	Levelized over 15 years
Large Wind (>100 kW)	$0.116	Fixed for 20 years

Small Wind (≤ 100 kW)	$0.258	Fixed for 20 years
Hydroelectric	$0.130	Fixed for 20 years
Food Waste Anaerobic Digestion	$0.208	Fixed for 20 years
Solar	$0.130	Fixed for 25 years

In 2017 and 2018, a time-intensive update to the cash-flow model was conducted, including updated assumptions, and it yielded no change to the price caps. The Department recognizes that several of the assumptions used to calculate the current price caps have changed (i.e. inflation rate, tax rate, depreciation expense, cost of solar PV modules), in offsetting directions. In aggregate, we would expect to see downward pressure on the existing price caps; however, the current price caps continue to represent a reasonable estimate of the cost to build. These price caps also encourage the continued participation of developers working on technologies other than solar in the Standard Offer Program.

The Developer Block is broken into the Technology Diversity Block and the Price Competitive Block. In the Technology Diversity Block, the 2019 RFP yielded seventeen proposals totaling 2.974 MW. Fourteen of the proposals were for small wind totaling 1.0 MW, and the remaining were for food waste projects. All the bids received were within 3% of the price caps, suggesting that there is developer interest at these levels, and the goal of technology diversity is being achieved. All bids in this block were awarded contracts.

In the Price Competitive Block, the price cap is at a level that encourages developer participation and results in competitively priced bids. In the 2019 RFP, this block yielded nineteen proposals for a total of 41.8 MW, all for solar projects. The proposed prices ranged from 8.38 cents per kWh up to 11.99 cents per kWh (excluding a bid of 99.81 cents per kWh, which exceed the price cap and was presumably an error). Four projects totaling 8.8 MW were awarded contracts, with the highest contract price being 9.19 cents per kWh.

The Provider Block, however, elicits less competition and proposals in past RFPs have been exclusively for solar at prices near the price cap, which is significantly higher than bids for similar projects in the Developer Block. The Department recommends that prices awarded in this block be capped at 110% of the highest awarded Price Competitive Block contract, and not exceed 13 cents per kWh. In 2019, this would have translated to 10.11 cents per kWh compared to the actual Provider Block contract prices of 12 cents per kWh and 12.4 cents per kWh. This method would most likely lower the price cap for the Provider Block. More importantly, having an unknown price cap would require Provider Block bids to be competitively priced.

Sheffield-Highgate Export Interface ("SHEI")

The Department recommends that the 2020 RFP include a notification to proponents of transmission limitations, like in section 2.7 of the 2019 RFP. Such a notification would ensure that all proponents understand that projects proposed in the SHEI area, which are awarded a standard-offer contract, will be required to address the economic and transmission system concerns associated with generation in that area during the certificate of public good process.

Conclusion

The Department looks forward to discussing these matters at the upcoming PUC workshop on December 5, 2019 and appreciates the opportunity to provide these comments and recommendations.

Dated at Montpelier, Vermont this 30th day of November 2019.

VERMONT DEPARTMENT OF PUBLIC SERVICE

By: /s/ Alex Wing

Alexander Wing, Special Counsel
Department of Public Service
112 State Street
Montpelier, VT 05620-2601

cc: ePUC Service List

EXHIBIT C

This document has been electronically filed using ePUC.

STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 18-2820-INV

Investigation to review the avoided costs that serve as prices for the standard-offer program in 2019

RECOMMENDATIONS OF THE DEPARTMENT OF PUBLIC SERVICE ON AVOIDED COST PRICE CAPS FOR THE 2019 STANDARD OFFER PROGRAM SOLICITATION

Introduction

On August 2, 2018 the Public Utility Commission ("PUC") opened an investigation into programmatic adjustments to review the avoided costs that serve as prices for the standard-offer program in 2019. For the 2019 request for proposal ("RFP"), the PUC is retaining the technology allocation used in the 2018 RFP. The PUC requests parties submit comments and recommendations on avoided-cost prices for the 2019 solicitation. The Department of Public Service ("PSD" or "Department") recommends retaining the current standard-offer price caps for the 2019 RFP.

Price Cap Recommendations

The Department recommends leaving the standard-offer price caps that were used in the 2017 and 2018 RFPs unchanged for the 2019 RFP. The existing price caps, by technology are:

Technology	Price per kWh	Term
Biomass	$0.125	Levelized over 20 years
Landfill Gas	$0.090	Levelized over 15 years
Large Wind (>100 kW)	$0.116	Fixed for 20 years
Small Wind (≤ 100 kW)	$0.258	Fixed for 20 years
Hydroelectric	$0.130	Fixed for 20 years
Food Waste Anaerobic Digestion	$0.208	Fixed for 20 years
Solar	$0.130	Fixed for 25 years

In previous years, a time-intensive update of all assumptions that flowed through the cash-flow model was conducted, yielding no change to the price caps. The PSD recognizes that several of the assumptions used to calculate the current price caps have changed (i.e. inflation rate, tax rate, depreciation expense, cost of PV modules), in offsetting directions. In aggregate, we would expect to see downward pressure on the existing price caps; however, the current price caps continue to represent a reasonable estimate of the cost to build, and enable developers working on technologies other than solar continued participation in the Standard Offer Program.

In the price competitive block, the price cap is at a level that encourages developer participation and results in competitively priced bids. This block in the 2018 RFP yielded seven eligible bids for a total of 14.4 MW. In the technology diversity block, the limited bidding activity at or close to the price caps suggest that there is developer interest at these levels (though limited), which is a primary goal.

If other interested parties are inclined to propose changes to the current price caps, those recommendations should be supported by a detailed accounting of project costs.

The Department looks forward to discussing these matters at the upcoming PUC workshop on September 10, 2018 and appreciates the opportunity to provide these comments and recommendations.

Dated at Montpelier, Vermont this 31st day of August, 2018

VERMONT DEPARTMENT OF PUBLIC SERVICE

By: Sheila Grace

Sheila Grace, Special Counsel
112 State Street
Montpelier, VT 05620-2601
(802) 828-3762
sheila.grace@vermont.gov

EXHIBIT D

STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Investigation into programmatic adjustments to the standard-offer program for 2018	))	Case No. 17-3935-INV

RECOMMENDATIONS OF THE DEPARTMENT OF PUBLIC SERVICE ON CAPACITY ALLOCATIONS AND AVOIDED COST PRICE CAPS FOR THE 2018 STANDARD OFFER PROGRAM SOLICITATION

Introduction

On August 22, 2017 the Public Utility Commission (PUC) opened an investigation into programmatic adjustments to the Standard Offer program for 2018. In that Order the PUC requested parties to submit comments and recommendations on capacity allocation and avoided-cost prices for the 2018 solicitation. The Department of Public Service (PSD or Department) offers the following responses to that request:

As required by 30 V.S.A. § 8005a(c)(1)(A), there will be 7.5 MW of renewable energy capacity made available as new Standard Offer contracts to bidders in the 2018 auction, along with any carry-over capacity that was not awarded in conjunction with the 2017 RFP. While the PSD is supportive of the prior PUC decisions allocating capacity among technologies and reserving capacity for non-solar technologies we do not yet make a recommendation for capacity allocation for the 2018 RFP. Given a variety of factors explained in greater detail below, rather than recommend an allocation scheme now, PSD proposes that the November 7, 2017 workshop include a discussion of program modifications that might alleviate problems associated with low participation and a lack of competition in the Technology Diversity Block.

The Department does make a number of recommendations related to avoided cost price caps which are presented in a separate document titled: *Department of Public Service Recommendations for Input Assumptions to Calculation of Standard Offer Bid Price Caps (*attached as Exhibit 1), which includes the cash flow modeling assumptions to be used in setting bid price caps for each technology group.

Capacity Allocation

In its Order of February 12, 2016 in Docket 7873, the PUC established a capacity allocation scheme for the 2016 Standard Offer program, in response to stakeholder comments supporting a mechanism that is "stable, predictable and transparent," which was intended to remain in place through the end of the program in 2021. This allocation scheme set aside approximately two thirds of the developer block capacity into a technology diversity tranche, which was itself divided into six equal segments each reserved for a different non-solar technology.[1] In that phase of Docket 7873, (which culminated with the issuance of the 2016 RFP) the Department had proposed a variety of allocation schemes sharing the same aim,of ensuring non-solar technologies an ongoing opportunity to improve their cost efficiencies and become more competitive with Solar (regardless of whether those opportunities were ultimately utilized). As such PSD supported the PUC's February 2016 decision as one that reasonably balanced the statutory goals of the program.

In subsequent Orders issued in Docket 8817, initiated by the PUC in September of 2016 to determine the avoided cost price caps and allocation schemes for the 2017 RFP, the PUC departed from the above described allocation scheme to accommodate a new statutory requirement that obligated the Commission to reserve a prescribed amount of capacity for "preferred location" projects. *See* 30 V.S.A § 8005a(D). In that proceeding, the Department had proposed an allocation scheme that allocated the necessary capacity for the preferred location projects while retaining as much as possible of the allocation scheme established by the February 2016 Order. Through Orders issued on March 2, 2017 and March 29, 2017, the Commission reduced the capacity allocated to the technology diversity tranche to about one third of the amount available in the developer block, and divided that capacity into two equal shares to be reserved for Small Wind and Food Waste projects.

As the PUC had pointed out in its February 12, 2016 Order:

> Any technology allocation must balance statutory goals and directives that may seemingly be at odds — for instance, supporting the inclusion in Vermont's retail electric supply portfolio of a diversity of renewable energy projects, both in size and in technology, while at the same time ensuring the timely development of such projects at the lowest feasible cost.[2]

The results of the past two auctions, however, have demonstrated that the goal of development at the lowest feasible cost is not being met due to insufficient competition amongst non-solar technologies. The lack of competition between participants in the Technology Diversity tranche has resulted in bids that are at or near the technology-specific price cap for each non-solar technology.

In the 2017 RFP responses, there were two technology diversity segments, one each for small wind and food waste. Thirteen projects were bid into the small wind block by only two developers. The price cap for small wind was set by the PUC at $0.258, and the prices bid in by the two developers ranged from a low of $0.2520 (2.3% below the price cap) to a high of the

[1] The non-solar technologies are Biomass, Hydro, Small Wind, Large Wind, Food Waste, Landfill Methane). The Price-Competitive portion of the Developer block was set at 2.2 MW through 2018 and increased to 4.4 MW through the end of the program in 2021.
[2] PUC Docket Nos. 7873 & 7874 Order of February 12, 2016 at 9.

price cap itself. The price cap for food waste was \$0.208 and two bids were received in this category, one at the price cap and the other at \$0.2050 (1.4% below the price cap). In the prior year's RFP, there was four small wind projects, all of which bid at the price cap of \$0.251, and one large wind, which also bid at the price cap of \$0.116. By comparison, the lowest price for a solar project selected was more than 30% below the 2017 price cap and over 40% below the 2016 price cap.

The Department interprets these outcomes as an indication that there is not sufficient competition in the technology diversity blocks of the standard offer program to induce downward pressure on the bids of non-solar projects. The PUC is thus faced with a choice either to preserve the current approach to encouraging technology diversity, which has come at a relatively high cost to ratepayers, or develop an alternative approach that provides greater assurance that technological diversity is achieved at the lowest possible cost.

Without a competitive environment among non-solar technologies there is little purpose in inviting those technology groups into a technology-specific auction. As the above numbers demonstrate, there have only been a small number of bids at or very near the calculated price caps, effectively relegating the calculated bid price cap to an administrative price.

The most straightforward way to achieve the lowest cost development of renewable energy projects would be to simply end the technology set-asides.[3]

As an alternative, the Department presents two ideas below for discussion at the November 7, 2017 workshop that could be incorporated into the program to strike a better balance between the competing goals of resource diversity and lowest cost for ratepayers.

PSD Alternative Proposal # 1 - Post-auction publication of price caps

Instead of adopting and publicizing a bid price cap before the RFP is sent out, the PUC could wait until bids are received to announce the cap and accept or reject bids accordingly. For this arrangement to be workable the PUC process would need to focus on development cost assumptions for each technology rather than discrete cost caps recommendations. The PUC could then weigh the information and supporting evidence submitted in response and formulate a ruling to adopt specific assumptions and values to inform calculation of the cap. However the price decision of the PUC would not be made known to parties until after the auction had been executed. This arrangement could encourage the circulation of a greater quantity of evidence-based cost information by more parties than has customarily been presented in Standard Offer proceedings, especially for non-solar technologies. In the accompanying document,

[3] However, as the Commission is aware, an appeal contesting the elimination of the Large Wind technology set-aside for the 2017 RFP is pending before the Vermont Supreme Court in Case No. 2017-165. In that matter, the Department, as Appellee, has urged affirmance of the Commission Order eliminating the Large Wind set aside on the grounds that technology diversity is but one of many competing goals of the Standard Offer program, and that the Commission's decision was both within its discretion as well as consistent with the statute authorizing the program.

Recommended Cash Flow Modeling Assumptions, The Department has formatted its recommendations to accord with the logistics of withholding price cap rulings in this way. Other parties could easily do the same.

PSD Alternative Proposal # 2 - Open book bids for non-solar technologies

Another possibility, compatible with the above proposal, is to require non-solar auction participants to submit open-book bids. This would require any bidder seeking to bid a project into the Technology Diversity Block, to provide full documentation of the cost estimates that informed their specific bid price. This approach would recognize the fact that where no pre-existing competitive market dynamics exists, a traditional auction mechanism cannot ensure selection of the most cost-efficient projects, and that this situation calls for fuller regulatory involvement with the bid process.

Both proposals would be most effective if the PUC directed the Standard Offer Facilitator to collect project development costs, as contemplated in Paragraph 12 of the standard offer contract. The Department is willing to provide the template for use in this reporting effort, and the template PSD has developed could also be used for submission of open-book bids. PSD suggests that it may be useful to delay any further allocations to a Technology Diversity Block until after such cost information has been collected and analyzed.

In summary PSD recommends that the PUC carefully consider changes to the process, and even whether to continue including non-solar projects into the standard offer auction mechanism, before ordering any specific capacity allocation scheme that reserves capacity in a Technology Diversity Block. While PSD is supportive of a Technology Diversity Block in concept, the set-aside has not proven compatible with an auction construct that pre-supposes a competitive market. Pursuant to current law there will be 7.5 MW of new standard offer capacity to award in 2018 (with 15% going to the Provider Block), and 10 MW of new capacity to award thereafter in years 2019 through 2021 (with 20% going to the Provider Block). As noted above there remain uncertainties associated with the pending Vermont Supreme Court appeal of the PUC elimination of the Large Wind category from last year's auction. In addition, the PUC is still reviewing the 2017 RFP submissions and the determinations made in that proceeding may provide useful in making decisions for the 2018 RFP.

The decision of how much of this capacity to set aside for a Technology Diversity block will depend on what measures the PUC resolves to take to mitigate the information asymmetries between regulators and program participants. Should one or both of the above modifications be implemented, PSD could support a future Technology Diversity tranche of the size that has been set-aside in the past couple of years. In addition, the last year has shown that legislative changes to the program can compromise attempts to impose year-to-year consistency in how the program allocates capacity.

Price Cap Recommendations

At this time, the Department is intentionally not recommending specific bid price caps. Instead, in Attachment 1 - *PSD Recommended Cash Flow Modeling Assumptions,* PSD proposes only the values and assumptions that would inform the ultimate calculation of those bid price caps. The reasoning for only recommending calculation input assumptions at this time is two-fold. First, the initial focus of the proceeding should be on the accuracy and reasonableness of each party's assessment of the *whole* cost to develop the eligible technologies. Consequently, presenting price cap recommendations up front runs the risk of shifting attention to only certain cost components and diluting the accuracy of the overall composition of development costs. Second, this approach is consistent with the discussion above regarding technology diversity and possible modifications to the administration of the auction that would have the PUC keep the price caps unknown to bidders until all bids are received.

Sheffield Highgate Export Interface

The Department wishes to highlight one other matter of significance that may have implications for the standard offer program. As the Commission, various distribution utilities, and many project developers are aware, there may be renewable energy development constraint issues associated with what is known as the Sheffield Highgate Export Interface (SHEI). A full description of the SHEI can be found at the Vermont System Planning Committee website[4]. However, in summary, the amount of energy generation and imports into northern Vermont can and at times has, exceeded the amount of load and transmission than can be accommodated in the area. In practice this means that generation within the SHEI geographic area must at times be curtailed to ensure reliability. Permitting the construction of additional generation into the area is quite likely to increase the number of hours of during which curtailment will be necessary.

The Department does not believe that Vermonter's interests are well-served by having the standard offer program further exacerbate the constraints and it is also unclear whether such projects could even receive a certificate of public good under applicable Section 248 criteria and given the statutory language of the standard offer program, which in 30 V.S.A. § 8005a(d)(2), contemplates that the location of a specific project must provide a benefit the grid. Under the current circumstances, the Department recommends that it would be appropriate to also consider the negative impacts that a project can have on the system.

PSD recommends that the PUC place this item on the agenda for discussion at the upcoming workshop. The Department sees two potential options for addressing the issue of standard offer projects located within the SHEI. The first would be for the PUC to not accept any new projects within the area. The second would be for the PUC to provide an automatic price adder for any projects within the area of constraint; this latter option would discourage projects but could still allow projects with significantly lowered costs to compete in the RFP process. If either option

[4] https://www.vermontspc.com/grid-planning/shei-info

were employed, the PUC could direct the Standard Offer Facilitator to work with VELCO in identifying any projects located within the constrained area to appropriately inform the PUC, potential bidders and stakeholders about any alterations to the standard offer contract or RFP process necessary to address the SHEI issue.

The Department looks forward to discussing the above described matters at the upcoming PUC workshop and appreciates the opportunity to provide these comments and recommendations.

Ed McNamara

Ed McNamara
Policy and Planning Director
Department of Public Service

EXHIBIT E

Department of Public Service Recommendations for Input Assumptions to Calculation of Standard Offer Bid Price Caps[1]

This document presents the recommendations of the Department of Public Service (PSD), as of November 20, 2017, for the input assumptions to be used in the calculation of bid price caps for the 2018 RFP for Small Wind, Solar, Food Waste and Farm Waste technology groups PSD is not aware of any market interest in developing standard offer projects for technologies other than the Small Wind, Solar and Digester groups, and consequently does not presently recommend any new technology-specific modeling assumptions for Large Wind, Hydro, Biomass, or Landfill Methane groups, In the interest of efficient use of time and resources throughout standard offer proceedings, PSD proposes that PUC require any future auction participants to make a demonstrable show of interest in competing for a standard offer contract prior to the opening of an investigation to set allocation schemes and bid price caps. This way, no time and energy will be wasted reviewing modeling assumptions for technologies that do not intend to participate in the auction and reallocating any capacity reserved for those technologies in the administration of the auction.

General Cost Assumptions

The input assumptions in this section are generally applicable to the cash flow modeling for all technology groups. Unless otherwise specified, these assumptions should be applied consistently across technology groups.

Rate of Inflation

- Current Assumption:
  - 1.86% annually for life of the project, the official projection of the Cleveland Federal Reserve, as of the Fall of 2016
- Proposed Assumption:
  - 1.89% annually for the life of the project, the current official projection of the Cleveland Federal Reserve.[2]

Amount of Debt Repayment Reserves

- Current Assumption:
  - Wind and Solar
    - One half of the amount of the first-year long-term debt payment, placed into a reserve account earning interest at the rate of inflation until released into operating income at the end of the debt term.
  - Food waste
    - No Debt Reserve

[1] This document is an updated version of Attachment 1 to PSD's October 20th filing in this proceeding and includes several new formatting edits. All recommendations new to this version are called out in red line.
[2] https://www.clevelandfed.org/en/our-research/indicators-and-data/inflation-expectations.aspx

- Farm Waste
  - No Debt Reserve
- Proposed Assumption:
  - All Technologies
    - One half of the amount of the first-year long-term debt payment, placed into a reserve account earning interest at the rate of inflation until released into operating income at the end of the debt term.

<u>Amount of Maintenance Reserves</u>

- Current Assumption:
  - Wind, Solar, Food Waste, Farm Waste
    - No Maintenance Reserves
- Proposed Assumption:
  - All Technologies
    - No Maintenance Reserves

<u>Amount of Working Capital Reserves</u>

- Current Assumption:
  - Wind and Solar:
    - One half of the amount of the first-year operating expense, placed into a reserve account earning interest at the rate of inflation until released into operating income in last year of the project life.
  - Food Waste
    - One eighth of the amount of the first-year operating expense, placed into a reserve account earning interest at the rate of inflation until released into operating income in last year of the project life.
  - Farm Waste
    - No working capital reserves
- Proposed Assumption:
  - All technologies
    - One eighth of the amount of the first-year operating expense, placed into a reserve account earning interest at the rate of inflation until released into operating income in last year of the project life.

<u>Financing Costs</u>

- Current Assumption:
  - Wind and Solar
    - 3.0% charged on total debt principal for lender's fees plus an APR of 5% charged on the total amount of install costs for four and a half months to cover interest during construction (IDC). No tax equity investor fee.
  - Food Waste
    - 2.5% charged on total debt principal for lender's fees plus an APR of 3% charged on the total debt principal for twelve months to cover IDC. No tax equity investor fee.
  - Farm Waste

        - No lender's fees or IDC
- Proposed Assumption:
    - Wind, Solar and Food Waste
        - 2.0% charged on total debt principal for lender's fees plus an APR of 3,0% charged on the total debt principal for six months to cover IDC. No tax equity investor fee.
    - Farm Waste
        - No Change.

<u>Capital Structure</u>

- Current Assumption:
    - Wind and Solar
        - Short-term debt is 30% of financing at starting rate of 3.50% for term of 6 years
            - Rate increases 20 basis points each year
        - Long-term debt is 30% of financing at rate of 4.50% for term of 18 years
            - Rate increases 25 basis points each year for first 7 years
        - Equity is 40% of financing, earning 9.02% return, GMP's current-at-the-time approved ROE
    - Food Waste
        - Total debt is 60% of financing at flat rate of 6.00% for term of 18 years
        - Equity is 40% of financing, earning 9.02% return, GMP's current-at-the-time approved ROE
    - Farm Waste
        - Grant funding reduces installed costs by the lesser of 25% of total installed costs or $500,000
        - Total debt is 60% of financing at flat rate of 3.75% for a term of 20 years
        - Equity is 40% of financing, earning 9.02% return, GMP's current-at-the-time approved ROE
- Proposed Assumption:
    - Wind, Solar and Food Waste
        - Short-term debt is 30% of financing at starting rate of 3.50% for term of 6 years
            - Rate increases 20 basis points each year.
        - Long-term debt is 30% of financing at rate of 4.50% for term of 18 years
            - Rate increases 20 basis points each year for first 7 years.
        - Equity is 40% of financing, earning 8.75% return, PSD's recommended ROE in the current GMP rate case (yet to be approved).
    - Farm Waste
        - Grant funding reduces installed costs by the lesser of 25% of total installed costs or $500,000
        - Total debt is 60% of financing at flat rate of 4.00% for a term of 20 years

<u>Equity is 40% of financing, earning 8.75% return, PSD's recommended ROE in the current GMP rate case (yet to be approved). Minimum Debt Service Coverage Ratio</u>

- Proposed Assumption:

- All technologies
  - Cash flow modeling outcomes must result in a minimum debt service coverage ratio of no less than 1.10

Income Tax

- Current Assumption:
  - Wind, Solar and Food Waste
    - State rate of 8.5%
    - Federal rate of 35%
  - Farm Waste
    - None explicit; possibly embedded in "Taxes and Fees" item.
- Proposed Assumption:
  - Wind, Solar and Farm Waste
    - No Change
  - Farm Waste
    - No change.

Investment Tax Credit (ITC)

- Current Assumption:
  - Wind and Solar
    - All non-transmission related install costs (95% of all install costs for Wind, 97.5% for Solar) are eligible for 30% Federal ITC, which is fully realized, along with a 7.2% State ITC, half of which is realized.
  - Food and Farm Waste
    - No ITC utilized.
- Proposed Assumption:
  - Solar
    - All non-transmission related install costs are eligible for 30% Federal ITC, the amount available through 2019, which is fully realized, along with a 7.2% State ITC, half of which is realized.[3]
  - Large Wind
    - All non-transmission related install costs are eligible for 12% Federal ITC, the amount available if in service by the end of 2019, which is fully realized, along with a 7.2% State ITC, half of which is realized.
  - Small Wind
    - Not eligible for any Federal or State ITC.[4]
  - Food and Farm Waste
    - Not eligible for any Federal or State ITC.[5]

[3] The 7.2% State ITC eligibility is calculated by multiplying the 24% allowed by the State with the 30% allowed by the IRS. See here for the State's "piggy-back" provision
[4] See here for the section of the Federal tax code governing energy ITC
[5] See here for the section of the Federal tax code governing energy ITC

State and Local Property Taxes on Underlying Parcel

- Current Assumption:
  - Wind, Solar, Food Waste
    - None explicit; State and Municipal taxes are assumed to be included in lease cost.
  - Farm Waste
    - None explicit; could be embedded in "Taxes & Fees" item amounting to a total first-year cost of $5 per kW-year, rising with inflation.
- Proposed Assumption:
  - All technologies
    - Land occupied by project is assessed at $10,000 per acre and taxed at a combined State and Municipal property rate equal to:
      - 1.50% State base rate tax on non-residential property plus
      - 0.75% Municipal property tax

State and Local Tax on Project "Fair Market Value"

- Current Assumption:
  - Wind, Solar and Food Waste
    - 70% of project NPV is taxed at the approximate average municipal rate of 0.50% resulting in fixed annual payment for life of project, per the official State taxation rule.
  - Farm Waste
    - None explicit; could be embedded in "Taxes & Fees" item amounting to first-year cost of $5 per kW-year, rising with inflation.
- Proposed Assumption:
  - Solar and Wind
    - 70% of project NPV is taxed at the Municipal property rate, resulting in fixed annual payment for life of project.
  - Digesters, Hydropower, Biomass, Landfill Methane
    - 70% of project NPV is taxed at combined State and Municipal property rate, resulting in fixed annual payment for life of project.

Depreciation Expense

- Current Assumption:
  - Wind and Solar
    - Amount expensed over 5 years, per MACRS depreciation table:
      - All non-transmission related installation costs (assumed to be 97.5% of total installation costs for Solar and 95% for Wind) reduced by half of the Federal ITC credit amount.
    - Amount expensed over 15 years, per MACRS depreciation table:
      - All transmission related installation cost (assumed to be 2.5% of total installation costs).
    - Amount expensed over 20 years, per MACRS depreciation table:
      - All financing costs, including IDC.

- Food Waste
  - Amount expensed over 7 years, per MACRS depreciation table:
    - All installation costs
- Farm Waste
  - Amount expensed straight line over 20 years:
    - All installation costs net of grant funding

- Proposed Assumption:
  - Wind, Solar, Food and Farm Waste
    - Amount expensed over 5 years, per MACRS depreciation table:
      - All non-transmission related installation costs reduced by half of the Federal ITC credit amount.
    - Amount expensed over 15 years, per MACRS depreciation table:
      - All transmission related installation cost.
    - Amount expensed over 20 years, per MACRS depreciation table:
      - All financing costs, including IDC.

Insurance Costs

- Current Assumption:
  - Wind and Solar
    - 0.40% of total install costs, rising with inflation
  - Food Waste
    - 1.0% of total install costs, rising with inflation
  - Farm Waste
    - 0.12% of total install costs (rising with inflation) for projects less than 150 kW
    - 0.20% of total install costs (rising with inflation) for projects greater than 150 kW
- Proposed Assumption:
  - All technologies
    - 0.40% of total install costs, rising with inflation.

Interconnection Costs

- Current Assumption:
  - Food Waste
    - $275 per kW-year, amounting to $82,500 for a 300-kW generator.
  - All other technologies
    - None explicit; Embedded in installed cost total.
- Proposed Assumption:
  - All Technologies
    - Project incurs $60,300 in interconnection-related costs, comprised of:
      - Interconnection application fee of $300, per Rule 5.500
      - System Impact Study cost of $20,000
      - Grid facility upgrade cost of $40,000

Installation Labor not related to Construction (Design, Consulting, Administration)

This cost item is defined as all engineering, legal and other consultant services as well as labor associated with site selection and project design.

- Current Assumption:
    - None explicit. Embedded in installed cost total.
- Proposed Assumption:
    - Project incurs $80,000 in labor costs associated with Design, Consulting, and Administration.

Composition of Installation Costs

For all technologies, total installation costs is comprised of the following components:

- Materials
    - Generation Equipment Costs
    - Balance of Plant Equipment/Materials Costs
- Direct Labor Costs
    - Construction/Installation Labor
    - Design, Consulting and Administrative Labor
        - Inclusive of system design labor, site search and selection, engineering services, and legal services.
- Interconnection Costs
    - Inclusive of Interconnection application fee, system impact study and any facility upgrade costs (see Interconnection section above)
- Permitting Fees
    - All fees paid to Town and State government. [6]

Composition of Operating Costs

For all technologies, total operating costs are inclusive of the following components (note not all technologies have operating costs in each category):

- Direct Labor Costs
- Maintenance Materials Costs
    - Generation Equipment Maintenance
    - Balance of Plant Maintenance
- Tax Costs
    - Income
    - Property
    - Taxes on Capacity, Production, "Fair Market Value."
- Land/Lease Costs
- Insurance Costs

[6] Note that in this cost taxonomy, the "Permitting Fees" category is meant to capture only direct charges for applying and/or acquiring a permit. The costs associated with preparing permit applications (e.g. petitions for Certificates of Public Good), should be categorized as labor costs.

- Feedstock and Byproduct Disposal Costs

Wind-Specific Cost Assumptions

WIND INSTALL COST

The 2017 RFP bid price caps assumed an installation cost of $3,000 per nameplate kW for Large Wind (defined as more than 100 kW) and approximately $5,800 per nameplate kW for Small Wind (defined as 100 kW and less). The Lawrence Berkeley National Laboratory (LBNL) has conducted recent market research finding that in 2016, the average installed cost for projects smaller than 5 MW was around $3,300 per nameplate kW.[7] Pacific Northwest National Laboratory (PNNL) has also conducted recent research finding that average install costs for small wind projects (defined as 100 kW turbine projects) fall within a range of $4,700 to $7,400 per kW.[8]

For the 2018 RFP, PSD does not recommend changing the Small Wind installed cost assumption of $5,800 per nameplate kW. For purposes of discussion and refinement of assumptions PSD has decomposed this total into the following cost items.

Generation Equipment Costs

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $4,000 per nameplate kW, amounting to $400,000 for a 100-kW generator

Balance of Plant Costs

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $600 per nameplate kW, amounting to $6,000 for a 300-kW generator

Construction/Installation Labor Costs

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - PSD has not been able to reliably distinguish direct installation labor costs from installed costs totals with the information it has reviewed. As such, at this time PSD leaves this cost item embedded in generation equipment and balance of plant cost totals.

Design, Consulting and Administrative Labor Costs

- Current Assumption:

[7] See https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf
[8] See http://wind.pnnl.gov/pdf/Benchmarking_US_Small_Wind_Costs_092817_PNNL.pdf and http://wind.pnnl.gov/distributedwind.asp

- None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $800 per nameplate kW, amounting to $80,000, as for all technologies. See *General Cost Assumptions* section above (*Installation Labor Costs not Related to Construction)*.

Interconnection costs

- Current Assumption:
  - None explicit. Embedded in total installed costs.
- Proposed Assumption:
  - $403 per kW, amounting to $40,300, as for all technologies. See *General Cost Assumptions* section above (*Interconnection Costs)*.

Permitting Fees

- Current Assumption:
  - None explicit.
- Proposed Assumption
  - No permitting fees incurred.

WIND OPERATING COST

The 2017 RFP price cap assumes first-year operating costs of around $56 per kW-year (rising with inflation) for Large Wind, and around $75 per kW-year (rising with inflation) for Small Wind (the corresponding project lifetime average operating costs—inclusive of inflation—are $64/kW-year and $86/kW-year respectively). The Table below breaks out the components of these operating cost totals and presents them as first year values, all of which rise with inflation in the cash flow model that calculated the 2017 RFP bid price cap

	Small Wind	Large Wind
Maintenance	$30/kW-year	$25/kW-year
Insurance	$22/kW-year	$12/kW-year
Tax[9]	$19/kW-year	$15/kW-year
Land/Lease[10]	$4/kW-year	$4/kW-year
Total	$75/kW-year	$56/kW-year

Both the currently assumed operating cost totals for Small and Large Wind are considerably higher than the $27 per kW-year that LBNL calculates as the average for a national sample of wind projects installed since 2010.[11] Similarly, PNNL calculates a somewhat lower average operations and maintenance cost for its sample of 100 kW systems. These discrepancies are no doubt attributable, in part, to differences in cost accounting between the Laboratories' research and the cash flow modeling done in this proceeding.[12] For

[9] Includes only the State Production Tax and a Municipal tax on the plant value
[10] Assumed to include State and Municipal tax on underlying parcel
[11] See https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf
[12] [Indeed, LBNL makes a point to highlight others market research that relies on different cost accounting methodologies and finds higher average operating costs, closer to those assumed in the calculations of the 2017 RFP price caps.

the 2018 RFP, PSD recommends assuming a total first-year operating cost of approximately $42 per kW-year for Small Wind, increasing annually with inflation.[13] For a 100-kW generator, this amounts to a first-year expense of around $42,000. The components of this recommended total (as well as the components of the current installed cost assumption) are detailed below. PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these and other cost modeling assumptions.

Labor Costs

- Current Assumption
    - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
    - $10 per kW-year, rising with inflation, amounting to a first-year total cost of $1,000.

Maintenance Costs for Generation Equipment

- Current Assumption:
    - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
    - $5 per kW-year, rising with inflation, amounting to a first-year total cost of $500.

Maintenance Costs for Balance of Plant

- Current Assumption:
    - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
    - No Balance of Plant maintenance costs incurred.

Tax Costs

- Current Assumption
    - $0.003 charged on each kWh produced, per current-at-the-time official production tax rate.[14]
        - This amounts to a flat annual cost of approximately $15,000 for Large Wind and $550 for Small Wind
    - State property tax on underlying parcel is assumed to be embedded in land lease costs
- Proposed Assumption:
    - State tax on production; $0.003 charged on each kWh produced
    - State and Municipal taxes on underlying property; See *General Cost Assumptions* section (*Tax Costs*).
    - Municipal tax on project "Fair Market Value"; See *General Cost Assumptions* section (*Tax Costs*).

Land Lease Costs

- Current Assumption:
    - Large and Small Wind:

[13] Note that this recommended total is before taxes.
[14] http://tax.vermont.gov/sites/tax/files/documents/WEF-602.pdf

    - $4.00 per kW-year, rising with inflation, assumed to be inclusive of State and Municipal property tax on underlying parcel, amounting to a first-year total cost of $8,000 for Large Wind and $400 for Small wind.
        - Assumes a land area requirement of 4 acres per MW at a lease cost of $1,000 per acre.
- Proposed Assumption:
    - Large and Small Wind
        - $3.50 per kW-year, rising with inflation
            - Assumes a land area requirement of 4 acres per MW at an annual lease cost of around $875 per acre, amounting to a first-year total cost of around $3,500 for Large Wind and $350 for Small Wind[15]
        - Includes an annual property tax bill of $0.90 per kW-year, calculated by multiplying a combined State and Municipal property tax rate of 2.25% with an underlying parcel value appraised at $10,000 per acre.[16]

<u>Insurance Costs</u>

- Current Assumption:
    - $22 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of $2,200 for a 100-kW generator.
- Proposed Assumption:
    - $30 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of approximately $3,000 for a 100-kW generator.
        - Calculated as 0.4% of total installed costs, as for all technologies. See *<u>General Cost Assumptions</u>* section (*Insurance Costs*).

OTHER WIND ITEMS

<u>Wind Bonus Depreciation</u>

- Current Assumption
    - Small Wind
        - An additional 40% of allowable Federal ITC basis is depreciated in year one, as provided for by the Consolidated Appropriations Act of 2015.[17] This assumes the equipment is put into service by the end of CY 2018.
    - Large Wind
        - Not eligible for bonus depreciation benefit
- Proposed Assumption
    - Wind (Small and Large)

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[15] To arrive at this annual lease cost assumption, PSD calculated the annual loan payment on a 30year mortgage for 4 and 0.4 acres (respectively for Large and Small Wind) priced at $10,000 per acre. The mortgage rate was set at 7% APR, the average rate nationally since 1990 for 30-year loan products. The annual loan payment was then marked up 10% to account for a margin charged by the lessor.

[16] The combined State and Municipal rate is equal to a 1.50% State base rate tax on non-residential property plus an assumed 0.75% Municipal property tax

[17] https://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs

- An additional 30% of allowable Federal ITC basis is depreciated in year one, as provided for by the Consolidated Appropriations Act of 2015. This assumes the equipment is put into service by the end of CY 2019.[18]

Wind Decommissioning Costs

- Current Assumption:
  - Both Small and Large wind are assumed to make use of a decommissioning fund. The total amount reserved assumes a decommissioning cost of $60 per kW.
- Proposed Assumption
  - No change.

Solar-Specific Cost Assumptions

SOLAR INSTALL COSTS

The calculation of the 2017 RFP bid cap assumed an installation cost of $1.82 per Watt, as previously recommended by PSD. This was modestly lower than the assumption used in the calculation of the 2016 RFP bid cap, which was informed by Vermont-specific market research performed in CY 2015 by CESA[19]

The modest decrease in installed cost assumptions between the 2016 and 2017 RFPs was consistent with projections made by LBNL in the summer of 2016.[20] LBNL has since updated their outlook and observes that though the declines in installed prices over the past couple years were indeed smaller than has historically been the case (though it bears noting, not as small as 1%), median installed prices for large non-residential systems have shown a year-to-date decline of $0.10 per Watt since the middle of 2017.[21] They surmise—not without caution—that this "Preliminary data…suggest that the pace of price reductions is picking back up," and that if "Extrapolated over a full year, these installed price [trends] would yield a…10% decline for large non-residential systems."

Since LBNL made this prognosis, the International Trade Commission has found that cheap foreign PV module imports have caused injury to American domestic manufacturers, and will soon go on to propose a remedy (to the Federal executive) that may result in a new import tariff regime that ultimately raises the domestic installed cost of Solar.[22] The cost of modules can represent as much as half of a project's installed cost and, as LBNL observes, "Among hardware costs, PV modules have been, far and away, the largest single driver for system-level installed price declines over the long-term." The 2015 CESA study found that module costs for a 2 MW project in Vermont cost the developer less than 70 cents per Watt on average. PSD expects that analogous module prices today are somewhat lower than this but cannot know how the resolution of the ITC suit will ultimately impact the cost of modules to Vermont developers.

[18] https://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs
[19] See http://www.cesa.org/assets/Uploads/Vermont-Solar-Cost-Study.pdf
[20] See: https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf
[21] See: https://emp.lbl.gov/sites/default/files/tracking_the_sun_10_report.pdf
[22] See https://www.greentechmedia.com/articles/read/trade-case-suniva-solarworld-final-arguments-commissioners-trump

Attempting to take account of this contingency, PSD recommends adopting an installed cost value that assumes no change in module costs since the 2016 RFP but continued declines in all other materials cost items including Mounting, Inverters, Data Acquisition System and the Balance of Plant equipment, as broken out below, totaling $1.78 per Watt. Judging from the 2015 CESA study, these cost items taken together represent approximately 25% of total installed costs. The recommended $1.78 is consistent with the above-quoted LBNL extrapolation of 10% year-over-year price declines to this 25% non-module materials share.[23]

- Materials totaling $1.15 per Watt
    - $0.76 per Watt for Modules
    - $0.21 per Watt for Mounting
    - $0.12 per Watt for Inverter
    - $0.01 per Watt for Data Acquisition System
    - $0.05 per Watt for Balance of Plant
- Labor totaling $0.59 per Watt
    - $0.56 per Watt for Construction Labor
    - $0.03 per Watt for Design, Consultant Services and Administrative Labor[24]
- Interconnection totaling $0.04 per Watt
    - $0.04 per Watt for application, system impact study, and any facility upgrade costs
- Permitting Fees totaling $0.01 per Watt
    - $0.01 per Watt for Town building permit[25]
- Total Installed Cost (from items above)
    - $1.78 per Watt

In the interest of transparency and standardization, the Department urges the PUC to require any alternative installed cost recommendations from other stakeholders to follow the above accounting format. In addition, PSD asks that the PUC require VEPPI to use this or a substantially similar accounting structure as a template to collect costs from existing standard offer projects, as authorized by the terms of the standard offer contract.

SOLAR OPERATING COSTS

The 2017 RFP price cap assumes first-year Solar operating costs of around $38 per kW-year, rising with inflation (the corresponding project lifetime average operating costs—inclusive of inflation—are around $46/kW-year). The Table below breaks out the components of these operating cost totals and presents them as first year values, all of which rise with inflation in the cash flow model used to calculate the 2017 RFP bid price cap.

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[23] (25% x $1.82 x 90%) + (75% x $1.82) = $1.77

[24] This includes the labor cost of site search and selection, engineering services, legal services, administrative support, and other consultant services.

[25] Note that costs associated with State permitting are included in the Labor item.

	Solar
Maintenance	$11/kW-year
Insurance	$7/kW-year
Tax[26]	$9/kW-year
Land/Lease[27]	$10/kW-year
Total	$38/kW-year

The currently assumed total Solar operating cost falls above what the research of National Renewable Energy Laboratory (NREL) and LBNL have found to be a typical range of $7 per kW-year to $27 per kW-year.[28] This discrepancy is no doubt attributable, in part, to differences in cost accounting between the Laboratories' research and the cash flow modeling done in this proceeding.

For the 2018 RFP, PSD recommends assuming a total first-year operating cost of approximately $14 per kW-year, increasing annually with inflation.[29] For a 2,200-kW generator, this amounts to a first-year expense of around $30,500. The components of this recommended total (as well as the components of the current installed cost assumption) are detailed below. PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these and other cost modeling assumptions.

<u>Labor Costs</u>

- Current Assumption
  - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
  - $0.45 per kW-year, rising with inflation, amounting to a first-year total cost of $1,000 for a 2,200-kW generator.

<u>Maintenance Costs for Generation Equipment</u>

- Current Assumption:
  - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
  - $0.23 per kW-year, rising with inflation, amounting to a first-year total cost of $500 for a 2,200-kW generator

<u>Maintenance Costs for Balance of Plant</u>

- Current Assumption:
  - None explicit. Embedded in maintenance item total.
- Proposed Assumption:
  - No Balance of Plant maintenance costs incurred.

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[26] Includes only the State Uniform Capacity Tax and a Municipal tax on the plant value
[27] Assumed to include State and Municipal tax on underlying parcel
[28] See https://www.nrel.gov/analysis/tech-lcoe-re-cost-est.html and https://emp.lbl.gov/utility-scale-solar/
[29] Note that this recommended total is before taxes.

Tax Costs

- Current Assumption
  - Uniform Capacity Tax (UCT) rate of $4.00 per kW charged to project nameplate capacity annually for life of project, amounting to a flat annual cost of $8,800
  - State property tax on underlying parcel is assumed to be embedded in land lease costs
- Proposed Assumption:
  - State tax on capacity; $4.00 per kW charged to project nameplate capacity annually for life of project, amounting to a flat annual cost of $8,800.
  - State and Municipal tax on underlying property; See <u>*General Cost Assumptions*</u> section (*Tax Costs*).
  - Municipal tax on project "Fair Market Value"; See <u>*General Cost Assumptions*</u> section (*Tax Costs*).

Land Lease Costs

- Current Assumption:
  - $6.80 per kW-year, rising with inflation, assumed to be inclusive of State and Municipal property tax on underlying parcel
    - Assumes land area requirement of 6.8 acres per MW at annual lease cost of $1500 per acre amounting to a first-year total cost of $22,440.
- Proposed Assumption:
  - $6.00 per kW-year, rising with inflation.
    - Assumes a land area requirement of 6.8 acres per MW at a lease cost of approximately $875 per acre, amounting to a first-year total cost of $13,138.[30] This is inclusive of an annual property tax bill of $1.53 per kW-year, calculated by multiplying a combined State and Municipal property tax rate of 2.25% with an assumed underlying parcel value appraised at $10,000 per acre.[31]

Insurance Costs

- Current Assumption:
  - $7 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of $15,793 for a 2,200-kW generator.
- Proposed Assumption:
  - No change. See <u>*General Cost Assumptions*</u> section (*Insurance Costs*).

SOLAR EQUIPMENT REPLACEMENT COSTS

Inverter Replacement Cost

- Current Assumption:

[30] To arrive at this annual lease cost assumption, PSD calculated the annual loan payment on a 30-year mortgage for approximately 15 acres priced at $10,000 per acre. The mortgage rate was set at 7% APR, the average nationally since 1990 for 30-year loan products. The resulting annual loan payment was then marked up 10% to account for a margin charged by the lessor to the developer.

[31] The combined State and Municipal rate is equal to a 1.50% State base rate tax on non-residential property plus an assumed 0.75% Municipal property tax

  - Inverter replaced in year 12 at cost of $400,000 accumulated incrementally from operating income into a reserve account earning interest at the assumed rate of inflation
- Proposed Assumption:
  - Inverter replaced in year 12 at cost of $234,000 accumulated incrementally from operating income into a reserve account earning interest at the assumed rate of inflation
    - This is consistent with an approximately 1% annual rate of decline from the PSD recommended present-day inverter cost assumption of $0.12 per nameplate Watt (see installed cost assumption recommendations).[32]

OTHER SOLAR ITEMS

Solar Bonus Depreciation

- Current Assumption:
  - An additional 40% of allowable Federal ITC basis is depreciated in year one, as provided for by the Consolidated Appropriations Act of 2015. This assumes the equipment is placed in service before the end of CY 2018.
- Proposed Assumption:
  - An additional 30% of allowable Federal ITC basis is depreciated in year one, as provided for by the Consolidated Appropriations Act of 2015. This assumes the equipment is placed in service before the end of CY 2019.[33]

Solar Decommissioning Costs

- Current Assumption
  - 0.04% of total decommissioning costs charged annually.
    - Total decommissioning cost are equivalent to $60 per nameplate kW
    - No decommissioning reserves are set aside at project outset
- Proposed Assumption
  - No change.

Food Waste-Specific Cost Assumptions

FOOD WASTE INTALLATION COSTS

The calculation of the 2017 RFP bid price cap assumed a total installed cost of $11,525 per nameplate kW. This assumption has remained unchanged since the 2015 RFP when it was first adopted (as proposed by REV). For the 2018 RFP, PSD recommends assuming a total installed cost of approximately $10,400 per nameplate kW. For a 300-kW generator this amounts to around $3.3 million. The components of this recommended total (as well as the components of the current installed cost assumption are detailed below). PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these modeling assumptions.

Generation Equipment Costs

- Current Assumption:

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[32] At $0.12 per Watt, the invertor materials cost of a 2.2 MW facility today is approximately $261,000.
[33] See https://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs

  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $1,500 per kW, amounting to $450,000 for a 300-kW generator

<u>Balance of Plant Costs</u>

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $8,500 per kW, amounting to $2,550,000 for a 300-kW generator

<u>Construction/Installation Labor Costs</u>

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - PSD has not been able to reliably distinguish direct installation labor costs from installed costs totals with the information it has reviewed. As such this item is left embedded in generation equipment and balance of plant costs.

<u>Design, Consulting and Administrative Labor Costs</u>

- Current Assumption:
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $267 per kW, amounting to $80,000, as for all technologies. See <u>*General Cost Assumptions*</u> section above (*Installation Labor Costs Not Related to Construction)*.

<u>Interconnection costs</u>

- Current Assumption:
  - $275 per kW, amounting to $82,500 for a 300-kW generator.
- Proposed Assumption:
  - $134 per kW, amounting to $40,300, as for all technologies. See <u>*General Cost Assumptions*</u> section above (*Interconnection Costs)*.

<u>Permitting Fees</u>

- Current Assumption
  - None explicit; embedded in total installed costs.
- Proposed Assumption:
  - $13 per kW, amounting to $4,000 for an air quality permit.

FOOD WASTE OPERATING COSTS

The calculation of the 2017 RFP bid price cap assumed a total current year operating cost of approximately $1,108 per kW-year, increasing annually with inflation (amounting to a current year expense of around $332,438). This assumption has remained unchanged since the 2015 RFP when it was first adopted. For the 2018 RFP, PSD recommends assuming a total first-year operating cost of approximately $1,200 per kW-year, increasing annually with inflation.[34] For a 300-kW generator, this amounts to a first-year expense of around $362,000. The components of this recommended total (as well as the components of the current installed cost assumption are detailed below. PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these and other cost modeling assumptions.

Labor Costs

- Current Assumption
  - $582 per kW-year first-year costs, rising with inflation
    - This assumes 4,992 hours paid at an average rate of $35.00 per hour amounting to a first-year cost of approximately $175,000 for a 300-kW generator.
- Proposed Assumption:
  - No Change

Maintenance Costs for Generation Equipment

- Current Assumption
  - $162 per kW-year in first-year costs (as recommended by REV), rising with inflation.
    - This assumes a project lifetime average of 2.35 cents of costs (in today's dollars) per kWh of production and a capacity factor of 78.2%, amounting to a first-year cost of approximately $48,000 for a 300-kW generator.
- Proposed Assumption:
  - $137.00 per kW-year in first-year costs, rising with inflation.
    - This assumes a project lifetime average of 2.00 cents of costs incurred (in today's dollars) per kWh of production and a capacity factor of 78.2%, amounting to a first-year cost of approximately for a 300 kW $41,000.

Maintenance Costs for Balance of Plant

- Current Assumption:
  - $50 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of $15,000 for a 300-kW generator
- Proposed Assumption:
  - $170.00 per kW-year in first-year costs, rising with inflation.
    - This assumes a project lifetime average annual cost equal to 2% of Balance of Plant installation costs amounting to a first-year cost of $51,000 for a 300-kW generator.

Tax Costs

- Current Assumption
  - $166 per kW-year in first year costs, rising with inflation.
    - This assumes that the appraised value comes to 80% of the total installed costs and is taxed at a combined municipal and State rate of 1.8%, amounting to a first-year total bill of $49,788.
- Proposed Assumption:

[34] Note that this recommended total is before taxes.

- See <u>*General Cost Assumptions*</u> section (*State and Local Taxes on "Fair Market Value," Income Tax*).

<u>Land Lease Costs</u>

- Current Assumption
    - $33 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of $10,000
- Proposed Assumption:
    - $7.33 per kW-year, rising with inflation, amounting to a first-year cost of $2,200.
        - Assumes a land area requirement of 2 acres at an annual per-acre lease cost of $1,103.[35]
            - Inclusive of an annual property tax bill of $1.50 per kW-year, calculated by multiplying a combined State and Municipal property tax rate of 2.25% with an assumed underlying parcel value appraised at $10,000 per acre.[36]

<u>Insurance Costs</u>

- Current Assumption:
    - $115 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of $34,500
        - Calculated as 1% of the total installed costs
- Proposed Assumption:
    - $44 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of approximately $12,497.
        - Calculated as 0.4% of total installed costs, as for all technologies. See <u>*General Cost Assumptions*</u> section (*Insurance Costs*).

<u>Feedstock and Disposal Costs</u>

- Current Assumption:
    - None explicit. Embedded in Equipment and Balance of Plant maintenance costs.
- Proposed Assumption:
    - Hydrogen Sulfide Mitigation:
        - $80 per kW-year, rising with inflation, amounting to a first-year cost of $24,000 for a 300-kW generator.
    - Other Consumables:
        - $187 per kW-year, rising with inflation, amounting to a first-year cost of $56,000 for a 300-kW generator.

[35] To arrive at this annual lease cost assumption, PSD calculated the annual loan payment on a 30-year mortgage for 2 acres of land priced at $10,000 per acre. The mortgage rate was set at 7% APR, the average nationally since 1990 for 30-year loan products. The resulting annual loan payment was then marked up 10% to account for a margin charged by the lessor to the developer.

[36] The combined State and Municipal rate is equal to a 1.50% State base rate tax on non-residential property plus an assumed 0.75% Municipal property tax.

FOOD WASTE EQUIPMENT REPLACEMENT COSTS

- Current Assumption:
  - None explicit; embedded in generation equipment maintenance total.
- Proposed Assumption:
  - Engine replaced in year 8 at cost of $450,000 accumulated incrementally from operating income into a reserve account earning interest at the assumed rate of inflation
    - This assumes a future cost of $1,500 per nameplate kW, the same as the original installed cost of Generation Equipment i.e. no equipment price inflation/deflation.

FOOD WASTE OTHER ITEMS

Tipping Fee Revenue

- Current Assumption:
  - Project takes in 33 tons per nameplate kW at a fee rate of $25 per ton, increasing with inflation, amounting to a first-year total of $250,000 for a 300-kW generator.
- Proposed Assumption:
  - No change.

Farm Waste-Specific Cost Assumptions

FARM WASTE INTALLATION COSTS

The calculation of the 2017 RFP bid price cap assumed a total installed cost of $13,108 per kW of nameplate capacity for "Small" digesters (defined as 150 kW or less) and $8,118 per kW for "Large" digesters (defined as more than 150 kW). These assumptions have remained unchanged since the 2015 RFP when they were first adopted. For the 2018 RFP, PSD recommends assuming a total installed cost of approximately $11,100 per nameplate kW for "Small" projects and approximately $8,500 per nameplate kW for large projects. For a small 150 kW project this amounts to a total installation cost of around $1.7 million. For a large 300 kW project, this amounts to a total installation cost of around $2.6 million. The components of this recommended total (as well as the components of the current installed cost assumption are detailed below). PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these and all other modeling assumptions.

Generation Equipment Costs

- Current Assumption:
  - Small (150 kW or less)
    - $3,277 per nameplate kW, amounting to$491,550 for a 150-kW generator
  - Large (more than 150 kW)
    - $2,030 per nameplate kW, amounting to $609,000 for a 300-kW generator
- Proposed Assumption:
  - Small (150 kW or less)

        - $1,500 per nameplate kW (consistent with Food Waste Generation Equipment Costs), amounting to $225,000 for a 150-kW generator.
    - Large (more than 150 kW)
        - $1,500 per nameplate kW (consistent with Food Waste Generation Equipment Costs), amounting to $450,000 for a 300-kW generator

<u>Balance of Plant Costs</u>

- Current Assumption:
    - Small (150 kW or less)
        - $9,831 per nameplate kW, amounting to approximately $1.5 million for a 150-kW generator
    - Large (more than 150 kW)
        - 6,089 per nameplate kW, amounting to approximately $1.8 million for a 300-kW generator.
- Proposed Assumption:
    - Small (150 kW or less)
        - $8,800 per nameplate kW, amounting to approximately $1.3 million for a 150-kW generator.
    - Large (more than 150 kW)
        - $6,600 per nameplate kW, amounting to approximately $2.0 million for a 300-kW generator

<u>Construction/Installation Labor Costs</u>

- Current Assumption:
    - Small and Large
        - None explicit; embedded in total installed costs.
- Proposed Assumption:
    - Small and Large

<u>PSD has not been able to reliably distinguish direct installation labor costs from installed costs totals with the information it has reviewed. As such this item is left embedded in generation equipment and balance of plant costs. Design, Consulting and Administrative Labor Costs</u>

- Current Assumption:
    - Small and Large
        - None explicit; embedded in total installed costs.
- Proposed Assumption:
    - Small (150 kW or less)
        - $533 per nameplate kW, amounting to $80,000, as for all technologies, regardless of size or type. See <u>*General Cost Assumptions*</u> section above (*Installation Labor Costs not Related to Construction)*.
    - Large (more than 150 kW)
        - $267 per nameplate kW, amounting to $200,000, as for all technologies, regardless of size or type. See <u>*General Cost Assumptions*</u> section above (*Installation Labor Costs not Related to Construction)*.

Interconnection costs

- Current Assumption:
    - Small and Large
        - None explicit; embedded in total installed costs.
- Proposed Assumption:
    - Small (150 kW or less)
        - $269 per nameplate kW, amounting to $40,300, as for all technologies. See General Cost Assumptions section above (*Interconnection Costs)*.
    - Large (more than 150 kW)
        - $134 per nameplate kW, amounting to $40,300, as for all technologies. See General Cost Assumptions section above (*Interconnection Costs)*.

Permitting Fees

- Current Assumption:
    - Small and Large
        - None
- Proposed Assumption:
    - Small and Large
        - No Change

FARM WASTE OPERATING COSTS

The calculation of the 2017 RFP bid price cap assumed a total current year operating cost of approximately $350 per kW-year, increasing annually with inflation, amounting to a $52,000 first year expense for Digesters 150 kW and smaller, and a $105,000 first year expense for digesters larger than 150 kW. This assumption has remained unchanged since the 2015 RFP when it was first adopted. For the 2018 RFP, PSD recommends assuming a total first-year operating cost of $608 and $468 per kW-year respectively for "Small" and "Large" Farm Waste generators, increasing annually with inflation.[37] This amounts to a "Small" 150 kW digester first-year expense of around $91,000 and a "Large" 300 kW digester first-year expense of around $140,000. The components of these recommended totals (as well as the components of the current installed cost assumption) are detailed below. PSD remains open to modifying this recommendation if warranted by information shared by other parties and welcomes the opportunity for more dialogue regarding these and other modeling assumptions.

Labor Costs

- Current Assumption
    - Small and Large
        - None explicit. Embedded in maintenance cost total.
- Proposed Assumption:
    - Small and Large (150 kW and less)
        - $170 per kW-year and $85 per kW-year respectively for Small and Large categories, amounting in both cases to a first-year cost of $25,550.

[37] Note that this recommended total is before taxes.

- Calculated as the amount of compensation for 2 hours of labor committed by farmer/operator per day at $35 per hour.

Maintenance Costs for Generation Equipment

- Current Assumption:
  - Small and Large
    - None explicit. Embedded in maintenance cost total.
- Proposed Assumption:
  - Small and Large
    - $137 per kW-year in first-year costs, rising with inflation, amounting to a first-year cost of approximately $20,500 for a 150-kW generator, and $41,100 for a 300-kW generator.
      - This assumes a project lifetime average of 2 cents of costs incurred (in today's dollars) per kWh of production and an annual capacity factor of 78.2%

Maintenance Costs for Balance of Plant

- Current Assumption:
  - Small and Large
    - None explicit. Embedded in maintenance cost total.
- Proposed Assumption:
  - Small and Large
    - $176 per kW-year and $132 per kW-year respectively for Small and Large categories, rising with inflation, amounting to a first-year cost of $26,400 for a 150-kW generator, and $39,600 for a 300-kW generator.
      - This assumes a project lifetime average annual cost equal to 2.0% of total Balance of Plant installation costs.

Tax Costs

- Current Assumption
  - $ per kW-year in first year Costs, rising with inflation
    - This assumes that the appraised value comes to 80% of the total installed costs and is taxed at a combined municipal and State rate of 1.8%, amounting to a first-year total bill of $49,788.
- Proposed Assumption:
  - See *General Cost Assumptions* section (*State and Local Property Taxes on Underlying Parcel, State and Local Tax on "Fair Market Value," Income Taxes*).

Land Lease Costs

- Current Assumption
  - Small and Large
    - No incremental land cost.
- Proposed Assumption

- Small and Large
    - No change.

Insurance Costs

- Current Assumption:
    - Small and Large
        - $16 per kW-year in first-year costs, rising with inflation, amounting to $2,375 for a 150-kW generator and $4,750 for a 300-kW generator.
- Proposed Assumption:
    - $44 per kW-year and $34 per kW-year respectively for Small and Large categories, rising with inflation, amounting to a first-year cost of $6,661 for a 150-kW generator, and $10,201 for a 300-kW generator.
        - Calculated as 0.4% of total installed costs, as for all technologies. See *General Cost Assumptions* section (*Insurance Costs*).

Feedstock and Disposal Costs

- Current Assumption:
    - Small and Large
        - Hydrogen sulfide mitigation; $80 per kW-year in first-year costs, rising with inflation, amounting to $12,095 for a 150-kW generator and $24,190 for a 300-kW generator
            - This assumes 1.5 gallons consumed per day per 100 head of cow at a price of $2.70 per gallon.
- Proposed Assumption:
    - Small and Large
        - No change.

FARM WASTE EQUIPMENT REPLACEMENT COSTS

Generator Replacement Cost

- Current Assumption:
    - Small and Large
        - Engine is overhauled in year 8 at cost of $1,444 per nameplate kW, financed entirely with debt at assumed APR of 7.5%.
- Proposed Assumption:
    - Small and Large
        - Engine overhauled in year 8 at cost of $450,000 accumulated incrementally from operating income into a reserve account earning interest at the assumed rate of inflation
            - This assumes a future cost of $1,500 per nameplate kW, the same as the original installed cost of Generation Equipment i.e. no equipment price inflation/deflation.

FARM WASTE OTHER ITEMS

- Current Assumption:
  - Small and Large
    - Bedding sales revenue; equivalent to $150 per kW-year, flat for life of project, amounting to around $45,000 in annual revenue for a 300-kW generator and $22,000 in annual revenue for a 150-kW generator.
    - Interest rebate; project owner receives an annual rebate amount equal to 38.55% of the average annual interest payment for the full term of the loan, amounting to around $9,800 in annual rebates for a 300-kW generator and $7,500 in annual rebates for a 150-kW generator
    - Rec sales revenue; all RECs are sold at a price of $0.04 cents per kWh, declining to a price of $0.01 cent by the end of the 20-year project lifetime.
- Proposed Assumption:
  - Small and Large
    - Bedding sales revenue; No change.
    - Interest rebate; No recommendation.
    - Rec sales revenue; all RECs are sold at a price of $0.025 per kWh.