STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7873

Programmatic Changes to the Standard-Offer Program )

and Docket No. 7874

Investigation into the Establishment of Standard-Offer )
Prices under the Sustainably Priced Energy Enterprise )
Development ("SPEED") Program )

Order entered: 3/1/2013

# ORDER RE ESTABLISHMENT OF STANDARD-OFFER PRICES AND PROGRAMMATIC CHANGES TO THE STANDARD-OFFER PROGRAM

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## I. Introduction

In 2012, the Vermont General Assembly passed Public Act 170,[1] which mandates significant changes to the Sustainably Priced Energy Enterprise Development ("SPEED") standard-offer program, pursuant to 30 V.S.A. §§ 8005a and 8006a.

In this Order, the Vermont Public Service Board ("Board") implements the significant changes to the standard-offer program required by Act 170, that include: (1) setting standard-offer prices for each renewable energy category at avoided cost, with the requirement that the Board employ a market-based mechanism, if certain enumerated conditions are met; (2) annually increasing the cumulative plant capacity of the standard-offer program until the 127.5 MW capacity of the program is reached, pursuant to a predetermined schedule; (3) reserving a portion of each annual increase in capacity for Vermont retail electricity providers; (4) adjusting the annual increase in capacity to account for greenhouse gas ("GHG") reduction credits; (5) allocating the cumulative plant capacity among different categories of renewable energy technologies; and (6) excluding from the cumulative plant capacity new standard-offer plants that the Board determines will provide sufficient benefits to the operation and management of the electric grid.

With regard to standard-offer prices, pursuant to Section 8005a(f), we establish a market-based mechanism for new standard-offer projects, for effect on April 1, 2013, and establish avoided costs to serve as caps on the standard-offer prices solicited through the market-based mechanism. This mechanism will replace the existing standard-offer pricing approach which bases contracts for renewable projects within the program on a calculated avoided cost.

With regard to the allocation of capacity among different renewable energy technologies under the program, pursuant to Section 8005a(c)(2), we are not establishing technology minimums or technology caps before the first year, and will open a proceeding to further investigate this issue following the 2013 market-based process.

With regard to the portion of the annual programmatic cap reserved for retail electricity providers ("Provider Block"), pursuant to Section 8005a(1)(B), we establish the procedure for

1. Public Act 170 (2012, Vt., Adj. Sess.). The text of Act 170 can be found at http://www.leg.state.vt.us/DOCS/2012/ACTS/ACT170.PDF.

selecting projects within the Provider Block, in addition to describing other procedures necessary for the implementation of this facet of the standard-offer program.

The statute also directs the Board to take steps to allow standard-offer projects to be developed that are not counted towards the programmatic cap, pursuant to Section 8005a(d)(2), if they provide sufficient benefit to the operation and management of the electric grid. In this Order, we adopt a screening framework and guidelines that upon implementation will provide potential standard-offer project developers with adequate information, at least annually, regarding transmission-constrained areas in which renewable generation having particular characteristics may provide sufficient benefit to the operation and management of the electric grid. Pursuant to the screening framework and guidelines, projects deemed to provide sufficient benefits shall not count toward the cumulative capacity amount of the standard-offer program. As more information develops, we will extend this screening framework to distribution-constrained areas to the extent feasible.

With regard to an adjustment of the programmatic cap for GHG reduction credits, pursuant to Sections 8005a(c)(1)(C) and 8006a(a), we establish a GHG Reduction Credit Program.

## II. Statutory and Procedural History

### A. Background

In 2005, the Vermont General Assembly established the SPEED program to encourage the development of renewable energy resources in Vermont, as well as the purchase of renewable power by the State's electric distribution utilities.[2] In response to the legislation, the Board promulgated Board Rule 4.300 to implement the SPEED program. Board Rule 4.300 also established a SPEED Facilitator to encourage the development of resources under the program.[3]

2. Those portions of Title 30 concerning renewable energy in general, and the SPEED program in particular, are set forth in 30 V.S.A. Chapter 89.

3. 30 V.S.A. § 8005(b)(1) also requires the Board to "name one or more entities" as SPEED facilitator. VEPP Inc. is the designated SPEED Facilitator and operates under a contract with the Board.

The activities of the SPEED Facilitator initially focused on meeting and explaining the SPEED program to potential renewable energy developers and to the power planners of the Vermont utilities responsible for meeting SPEED goals. To assist with that function, the Speed Facilitator has developed a SPEED website (www.vermontspeed.com). In addition to its work directly involving the SPEED program, the SPEED Facilitator also participates as a non-voting member of the Vermont System Planning Committee.[4]

Public Act 45, enacted in May of 2009, modified the SPEED program to include a state-wide standard-offer program. The SPEED standard-offer program required the Board to establish prices for long-term power-purchase contracts for SPEED projects. The statute required that the prices established by the Board be sufficient to allow developers of SPEED projects to recover their costs plus a return on their investment. The standard-offer program is open to SPEED projects with a nameplate capacity of 2.2 MW or less. The SPEED Facilitator distributes the energy and attendant costs to the Vermont distribution utilities based on each utility's *pro rata* share of total Vermont retail kWh sales for the previous calendar year.[5]

On October 19, 2009, the SPEED Facilitator began accepting applications for the program, subject to a 50 MW programmatic cap established under what was then Section 8005(b)(2). The SPEED Facilitator received applications far in excess of the capacity available under the programmatic cap. As of February 21, 2013, the approximate capacity of projects with executed standard-offer contracts is listed below by technology:

| Technology | Capacity (kW) | Projects |
|---|---|---|
| Solar PV | 39,680 | 30 |
| Biomass | 1,265 | 2 |

4. The Vermont System Planning Committee ("VSPC") was established pursuant to a Memorandum of Understanding among many parties in Docket 7081. The VSPC is designed to facilitate and support consideration of non-transmission alternatives to reliability problems in the state and to encourage public participation in the selection of solutions to reliability problems.

5. The standard-offer program creates an exemption for any Vermont utility "that establishes that it receives at least 25 percent of its energy from qualifying SPEED resources that were in operation on or before September 30, 2009 . . . ." Section 8005(b)(7). Only Washington Electric Cooperative, Inc. qualifies for exemption from the standard-offer program.

| | | |
|---|---|---|
| Wind | 0 | 0 |
| Farm Methane | 2,829 | 11 |
| Landfill Methane | 560 | 1 |
| Hydroelectric | 4,939 | 6 |
| Total | 49,273 | 49 |

Of those projects: (1) twenty-four have been commissioned (approximately 16.5 MW); (2) eight more have been issued Certificates of Public Good ("CPG") under 30 V.S.A. § 248 authorizing site preparation and construction (approximately 10.5 MW), but have not been commissioned; and (3) six are currently being reviewed by the Board. The remainder are still under development and have not requested a CPG.

On May 18, 2012, Public Act 170 became law. Public Act 170 mandates significant changes to the standard-offer program, that include: (1) annually increasing the cumulative plant capacity of the standard-offer program until the 127.5 MW capacity of the program is reached, pursuant to a predetermined schedule; (2) reserving a portion of each annual increase in capacity for Vermont retail electricity providers; (3) adjusting the annual increase in capacity to account for GHG reduction credits; (4) allocating the cumulative plant capacity among different categories of renewable energy technologies; and (5) excluding from the cumulative plant capacity plants using methane derived from agricultural operations and new standard-offer plants that the Board determines will provide sufficient benefits to the operation and management of the electric grid; (6) setting standard-offer prices for each renewable energy category at avoided cost, with the requirement that the Board employ a market-based mechanism, if certain enumerated conditions are met; and (7) determining the standard-offer price to be paid to existing hydroelectric plants.

The Board opened these Dockets to implement the statutory directive. Implementation of required programmatic changes was assigned to Docket 7873, while standard-offer pricing issues were directed to Docket 7874.

**B. Procedural History**

On June 8, 2012, the Board issued an Order Opening Investigation and Notice of Workshop in Dockets 7873 and 7874.

On June 22, 2012, Board Staff held a workshop to begin discussion of the issues and determine the process for reviewing and deciding the issues in these Dockets. At the workshop, Board staff requested comments regarding whether the Board should hire an independent consultant to assist with the price determinations. Participants agreed that it was appropriate for the Board to hire a consultant who would serve as an independent expert in the same manner as in Dockets 7523, 7533 and 7780 (the prior proceedings in which the Board implemented the standard-offer program and established prices based upon the statutory criteria). The Board subsequently executed a contract with Power Advisory, LLC ("Power Advisory") to assist in the determination of standard-offer prices.[6]

Board staff held additional workshops on August 14, 2012, August 23, 2012, September 25, 2012, November 29, 2012, January 10, 2013, and January 22, 2013.

Participants in these proceedings have made multiple filings of comments in response to issues. Comments were received from the following: Department of Public Service ("Department"), Allco Renewable Energy, LTD ("Allco"), City of Burlington Electric Department ("BED"); Green Mountain Power Corporation ("GMP"), Green Mountain Electric Supply, Inc., International Business Machines Corporation ("IBM"), Lake Champlain Regional Chamber of Commerce ("LCRCC"), Northern Power Systems, Renewable Energy Vermont ("REV"), Triland Partners LP ("Triland"), Vermont Electric Cooperative, Inc. ("VEC"), Vermont Public Power Supply Authority ("VPPSA"), VEPP Inc., Vermonters for a Clean Environment

6. In those cases, and in this one, the Board contracted for an independent expert. All parties were free to contact the independent expert at any time to discuss the issues on which he was providing input. The cash flow model employed to set avoided costs in this proceeding was the product of such collaboration during Docket 7533. The Board did not provide specific direction to the independent expert, except in the context of determinations during workshops or hearings at which other docket participants had an opportunity to propose alternatives and suggest different work tasks. In this case, the design of the market-based mechanism changed over time based upon the very useful suggestions of the participants. In this Order, the independent expert is referred to as "Power Advisory." However, except for the broad tasks defined in the contract for services and the specific directions provided during workshops and hearings or in orders or memoranda, the Board has not attempted to direct Power Advisory's work.

("VCE"), Vermont Independent Power Producers Association ("VIPPA"), Vermont Electric Power Company, Inc. ("VELCO"), and Winstanley Property Management, LLC ("Winstanley").

On August 8, 2012, in Docket 7874, the Board issued an Order instituting several revisions to the standard-offer contract form to implement the requirements of Act 170.

On August 24, 2012, in Docket 7873, the Board issued an Order determining that farm methane projects that now have standard-offer contracts, the capacity of which has previously been applied to the initial 50 MW cap on the standard-offer program, will continue to count toward the standard-offer programmatic cap. In addition, the Order determined that farm methane projects that receive standard-offer contracts after the passage of the Act 170 will not count toward the programmatic cap, consistent with 30 V.S.A. § 8005a(d).

On January 29, 2013, in Docket 7873, pursuant to Section 8006a, the Board issued an Order determining that IBM satisfies the ratepayer eligibility requirements defined in Section 8006a(b)(1), and approved IBM's independent third-party verifier of greenhouse gas reductions.

On February 7, 2013, in Docket 7874, pursuant to Section 8005(p), the Board issued an Order establishing the standard-offer price for existing hydroelectric plants with a nameplate capacity of 5 MW or less.

## III. Standard-Offer Prices and Market-Based Mechanism

On January 15, 2010, in Docket 7533, the Board issued an Order establishing standard-offer prices pursuant to Section 8005.[7] These prices replaced the statutorily set default prices which applied to standard-offer contracts entered into previously.

On January 23, 2012, in Docket 7780, the Board issued an Order revising the standard-offer prices for solar photovoltaic ("PV") projects and wind projects with a nameplate capacity of 100 kW or less. In addition, the Order retained the standard-offer prices for the remaining technology categories that were established in the January 15, 2010, Order.

Section 8005a(f)(3) requires that, no later than March 1, 2013, for effect on April 1, 2013, the Board develop standard-offer prices based on an avoided-cost methodology. This provision,

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7. Act 170 moved the requirements of the standard-offer program to Section 8005a. In addition, the statutory criteria for establishing the standard-offer prices have been altered over time.

added to the statute last year, also directs the Board to implement a market-based mechanism to distribute the programmatic cap if the Board finds the market-based mechanism to be consistent with federal law and the legislative goal of rapid deployment of new renewable resources at the lowest feasible cost. In addition, Section 8005a(f)(3) requires that the Board, annually thereafter, review the pricing mechanism and price determinations previously made "to decide whether they should be modified in any respect in order to achieve the goal and requirements of this subsection."

The establishment of a market-based mechanism to distribute the programmatic cap and the establishment of avoided costs to serve as caps on the standard-offer prices solicited through the market-based mechanism is addressed below.

## A. Avoided Costs

Section 8005a(f)(2)(A) requires that the standard-offer price be the avoided cost of the Vermont composite electric utility system if the Board finds that a market-based mechanism is inconsistent with either applicable federal law or the goal of timely development of standard-offer projects at the lowest feasible costs.

Section 8005a(f)(2)(B) defines avoided cost as:

> the incremental cost to retail electricity providers of electric energy or capacity or both, which, but for the purchase through the standard offer, such providers would obtain from distributed renewable generation that uses the same generation technology as the category of renewable energy for which the board is setting the price.

In addition, pursuant to Section 8005a(f)(B), the definition of avoided cost includes the consideration of each of the following:

> (i) The relevant cost data of the Vermont composite electric utility system.
> (ii) The terms of the contract, including the duration of the obligation.
> (iii) The availability, during the system's daily and seasonal peak periods, of capacity or energy purchased through the standard offer, and the estimated savings from mitigating peak load.
> (iv) The relationship of the availability of energy or capacity purchased through the standard offer to the ability of the Vermont composite electric utility system or a portion thereof to avoid costs.

(v) The costs or savings resulting from variations in line losses and other impacts to the transmission or distribution system from those that would have existed in the absence of purchases through the standard offer.
(vi) The supply and cost characteristics of plants eligible to receive the standard offer.

The determination of avoided cost prices pursuant to Section 8005a(f)(2) is addressed below. Pursuant to Section 8005a(f)(2)(A)(ii), the avoided costs, except for farm methane, serve as caps on the prices solicited through the market-based mechanism.

Recommendations of Power Advisory

Power Advisory, with the active assistance of GMP, the Department, and REV, had previously developed a cash-flow model for evaluating the rates that a new standard-offer project would need to make a reasonable return. This model was used by the Board and parties to assist in the standard-offer price determinations the Board previously made in Docket 7533 and 7780. As the Board explained in the Docket 7533 Order establishing the avoided costs, the price inputs were intended to reflect the costs of a favorably sited and efficient facility. This was to ensure that rates did not provide excess returns to such facilities and protect ratepayers from incurring higher costs due to less optimal standard-offer projects.[8] Participants in these proceedings agreed to the use of this financial model with structural updates made by Power Advisory to determine avoided costs.[9]

The financial model projects the after-tax cash flows that would be available to the project developer and is commonly referred to as a cash flow model. The basic structure of the model is to determine a revenue stream over a given contract period (typically 20 years) that allows the developer to recover the costs of developing, building and operating a renewable energy generation project and earn the target return on equity. The model calculates the price in dollars per megawatt hour that will yield the annual after-tax cash flow necessary to achieve the

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8. Docket 7533, Order of 1/15/10 at 8-13.

9. The Board specifically solicited comments from parties on proposed changes to the cash-flow model. No party submitted such recommendations.

target return on equity.[10] To compute the net annual after-tax cash flow, annual cash expenditures based on technology-specific cost and performance assumptions are subtracted from the cash inflows. These annual cash expenditures include insurance, operations and maintenance expenses, interest and principal payments, and income and property taxes. Cash inflows are typically limited to revenues from the sale of electricity under the standard-offer contract.[11]

Power Advisory recommends that the standard-offer prices for solar photovoltaic ("PV") be revised. Power Advisory contends that solar PV costs have continued to decline and the prices should be revised to ensure that the standard-offer pricing reflects the underlying costs to build and operate a project. Power Advisory recommends that the solar PV price be updated from the previous price determination in Docket 7780, to reflect changes in capital costs and the treatment of property taxes. Power Advisory provided evidence that prices for PV modules have declined by 25 to 34 percent in 2012. Solar PV modules are forecasted to be $0.67 per watt in the first quarter of 2013, with a further reduction to $0.55 per watt forecasted for the fourth quarter of 2013.[12] A solar module cost of $0.55 per watt represents a total capital cost of $3.06 per watt for solar projects. Power Advisory also recommends that the property tax payments in the cash flow model be escalated by inflation, rather than the payments declining as assumed in the previous price determination.[13]

Using the updated capital-cost and the property-tax-payment assumptions, the financial model calculates an avoided cost for solar PV standard-offer projects of $0.257 per kWh.[14]

Power Advisory also observes that large wind projects (greater than 100 kW capacity) have suffered from high attrition rates which suggests that current pricing may understate project costs. Power Advisory was unable to find reliable cost information to develop a revised

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10. Dalton pf. at 6.

11. Dalton pf. at 7.

12. Dalton pf. at 10.

13. Dalton pf. at 11.

14. Dalton pf. at 10-11; exhibit JCD-2.

standard-offer avoided-cost estimate for large wind projects, and states that the implementation of a market-based mechanism will reduce the need to rely on such an estimate.[15]

Power Advisory did not recommend changes to any of the other classes of renewable projects for which the Board has previously set prices (or permitted the statutory default price established in 2009 to remain in effect).

Participants' Comments

For purposes of establishing avoided costs, REV supports utilizing the solar module costs that have occurred during the past year, as opposed to forecasted pricing. REV suggests that there is not a considerable amount of evidence to support a further reduction in solar module pricing. REV contends that there is little evidence to support either the assumption of an increase in pricing or a decrease in pricing at this time since pricing is primarily driven by an imbalance in global supply and demand, not technological improvements. As a result, REV recommends that the Board adopt a higher avoided cost than does Power Advisory.[16]

The Department supports adopting an avoided cost of $0.257 per kWh for solar PV projects, as proposed by Power Advisory. The Department agrees that solar PV module costs are declining and are expected to decline further. The Department contends that, given that the avoided cost will apply to projects that may not be built for several years — projects which are proposed on April 1, 2013, will not be under contract until July 1, 2013, and will have a two-year window before the commission deadline expires — using a forecast module price for late 2013 provides a reasonable basis for estimating an appropriate avoided cost for the time of commissioning while still promoting timely development of projects. The Department recommends that avoided costs for other technologies remain consistent with prices developed recently in Docket 7780, given that neither Power Advisory, nor any party provided information updating assumptions to the Board's existing model.[17]

15. Dalton pf. at 11.

16. REV Comments of 1/31/13 at 3.

17. Department Comments of 1/31/13 at 2.

GMP contends that the assumption and results for the financial model appear to be within "reasonable ranges," but argues that Power Advisory did not provide final recommendations for avoided costs. GMP recommends that Power Advisory be required to make a compliance filing that includes all updated models and avoided-cost benchmarks.[18]

Discussion and Conclusion

Section 8005a(f)(2)(B) defines avoided cost as the "incremental cost to retail electricity providers of electric energy or capacity or both." In addition, pursuant to Section 8005a(f)(2)(B)(i)-(vi), in establishing a standard-offer price, the Board is required to consider the relevant cost data of the Vermont composite electric utility system, the duration of the potential contract, the availability of capacity or energy from the plant, the relationship of the availability of energy or capacity from the plant to the ability of the Vermont composite electric utility system to avoid costs, the costs or savings resulting from variations in line losses, and the supply and cost characteristics.

Sections 205 and 206 of the Federal Power Act[19] vest the Federal Energy Regulatory Commission ("FERC") with the exclusive authority to determine wholesale rates for electricity sold in interstate commerce. In 2010, FERC determined that as a general matter the rates set via a standard-offer program created under state law are therefore preempted by the Federal Power Act.[20] However, FERC further concluded that, because states have certain delegated authority to set wholesale rates under the Public Utility Regulatory Policies Act ("PURPA")[21] for at least some producers of wholesale power (referred to as "qualifying facilities"), there are circumstances in which a standard-offer program can withstand preemption scrutiny.[22] FERC's rules implementing PURPA require that states set the rates based on avoided cost, defined as "the

18. GMP Comments of 1/31/13 at 4.

19. 16 U.S.C. §§ 824d and 824e.

20. *California Pub. Util. Comm'n*, 132 FERC ¶ 61,047 (July 15, 2010) at ¶ 64.

21. 16 U.S.C. § 824a-3.

22. *California Pub. Util. Comm'n*, 132 FERC ¶ 61,047 (July 15, 2010) at ¶ 65.

incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility . . . , such utility would generate itself or purchase from another source."[23] In essence, FERC determined that standard-offer rates established under state law must not exceed the PURPA avoided cost.[24] Clarifying this initial determination in a subsequent order, FERC ruled that states may employ a "multi-tiered" avoided-cost structure in a standard offer program that takes into account such things as state-law requirements to purchase electricity from particular sources of energy.[25] This ruling essentially permits a state to establish rates for specific categories of renewable projects, provided those rates are set at avoided cost rather than some other methodology.

Board Rule 4.103(A) defines avoided cost as "the incremental cost to electric utilities of electric energy or capacity or both, which, but for the purchase from the qualifying facility such utilities would generate themselves or purchase from another source." With the advent of wholesale electric markets and recent FERC rulings, this standard has typically been thought of as the regional cost of wholesale power since the regional market determines the cost of the next increment of power.

The Rule 4.103(A) definition, however, does not take into account the legislative mandates that apply to the standard-offer program. Application of the term avoided cost under Section 8005a(f)(2)(B) includes the additional considerations that are included in the avoided-cost definition, in particular the "supply and cost characteristics of plants eligible to receive the standard offer." More significantly, the avoided cost under Section 8005a(f)(2)(B) is specified as the cost that a retail provider would, but for the standard offer program, obtain "from distributed renewable generation that uses the same generation technology as the category of renewable energy for which the board is setting the price." This language makes it clear that the legislature

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23. 18 C.F.R. §§ 292.101(b)(6) and 292.304(b).

24. *California Pub. Util. Comm'n*, 132 FERC ¶ 61,047 (July 15, 2010) at 67.

25. *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (October 21, 2010) at ¶ 26. FERC later rejected a further rehearing request. *See California Pub. Util. Comm'n*, 134 FERC ¶ 61,044 (January 20, 2011) at ¶ 30 (noting that "states have the authority to dictate the generation resources from which utilities may procure electric energy . . . so an avoided cost rate may also reflect a state requirement that utilities purchase their energy needs, from, for example, renewable resources").

does not seek to set prices based upon the electrical system as a whole (as set out in Rule 4.103(A) (*i.e.*, wholesale market prices). Rather the statute requires that we determine the avoided cost for each category of renewable resource. This is the same approach that we employed in Docket 7780 and that Power Advisory proposes here.[26] The use of the same financial model, updated to reflect new cost estimates for an efficiently sized and located renewable generation facility, is a reasonable method of implementing the statutory directives. In addition, the resulting avoided costs are consistent with recent FERC rulings, and accordingly consistent with applicable federal law.

With respect to the appropriate capital costs for solar projects, we are persuaded that current trends suggest continued declines in the cost of solar modules and systems, and a value of $3.06 per watt presented by Power Advisory is appropriate. While REV is, of course, correct that forecasting future prices for solar modules adds uncertainty, there has been a consistent trend in the solar industry of declining prices for solar panels. Power Advisory in Docket 7780 projected similar declines in 2012 forecast prices that we reflected in the standard-offer prices that we established last year. The actual 2012 model prices were consistent with the general projections. Power Advisory examined multiple sources of expert data to support the conclusion of a decline in module price forecast for 2013. Based upon these continuing trends, establishing prices now based upon the forecast of additional declines in module prices in the year 2013 is reasonable, especially given the projection is over a one-year time frame. Moreover, failure to do so is likely to result in prices that are above the actual avoided costs at the time.

We do not agree with GMP's contention that Power Advisory did not provide final recommendations for avoided costs and should be required to make a compliance filing that includes all updated models and avoided-costs benchmarks. Power Advisory provided evidence, including an exhibit with financial model results, to support his recommendations for solar avoided costs. Under the process that we adopted in December, Power Advisory was directed to adjust the cash flow model where there was evidence that the cost assumptions or other inputs to

26. As noted above, the standard-offer prices set in Docket 7533 were based upon cost, not avoided cost. However, the methodology as applied to individual categories of renewable projects is essentially the same. The avoided cost of the next solar project is, for all intents and purposes, the same as the cost of such facility.

the model may have changed. Parties were provided an opportunity to submit comments on those issues or recommended changes to prices. Except for the solar category, no party recommended any changes. Thus, there was no need to update any of the models except the solar one, which was provided to all parties.

Using the assumptions from the previous price determination in Docket 7780, with updates to reflect changes in capital costs and the treatment of property taxes, the financial model calculates an avoided cost of $0.257 per kWh. Accordingly, we establish an avoided cost for solar projects of $0.257 per kWh.

No party provided evidence to evaluate the existing standard-offer price for wind projects, biomass projects, farm methane projects, and hydroelectric projects. In addition, the opportunities for landfill gas are limited to already developed projects. The Department recommends that avoided costs for other technologies remain consistent with prices developed recently in Docket 7780. Therefore, we are establishing avoided costs, except for solar, that were identified as the standard-offer prices in the January 23, 2012, Order in Docket 7780.

Pursuant to Section 8005a(g), farm methane projects remain outside of the programmatic cap. Farm methane projects will receive a levelized standard-offer price of $0.141 per kWh and are not required to participate in a market-based mechanism.

Section 8005a(e) requires that the term of a standard offer "shall be 10 to 20 years, except that the term of a standard offer for a plant using solar power shall be 10 to 25 years." We conclude that the term of a standard-offer contract should be based on the term used to calculate the standard-offer avoided cost, and that the term should be based on the assumed life of the project capped by the statutory requirement of 20 or 25 years.[27] A plant life of 20 to 25 years assumes the efficient and reasonable operation of a new renewable energy project, and is consistent with the Board's determination, in Dockets 7533 and 7780, that standard-offer prices be established based on representative costs of a well-designed system that is installed in a location with supportive resource availability.

27. The Board set a term of 15 years for standard offers for landfill gas projects; however, this assumption is based on the fact that the fuel source for landfill gas will decline over time. Docket 7533, Order of 1/15/10 at 65.

In summary, the Board establishes the following avoided costs[28] pursuant to Section 8005a. The avoided costs, except for farm methane, serve as caps on the prices solicited through the market-based mechanism.

| **Avoided-Cost Schedule for Standard-Offer Projects ($/kWh)** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Biomass | Farm Methane | Hydroelectric | Landfill Gas | Wind >100 kW | Wind ≤ 100 kW | Solar PV |
| Levelized | 0.125 | 0.141 | 0.123 | 0.090 | 0.118 | 0.253 | 0.257 for 25 years |
| Year 1 | 0.121 | 0.136 | 0.119 | 0.087 | 0.113 | 0.245 | |
| Year 2 | 0.121 | 0.137 | 0.119 | 0.087 | 0.113 | 0.246 | |
| Year 3 | 0.122 | 0.137 | 0.120 | 0.088 | 0.114 | 0.247 | |
| Year 4 | 0.123 | 0.138 | 0.121 | 0.089 | 0.114 | 0.249 | |
| Year 5 | 0.124 | 0.139 | 0.121 | 0.089 | 0.115 | 0.250 | |
| Year 6 | 0.125 | 0.139 | 0.122 | 0.090 | 0.115 | 0.251 | |
| Year 7 | 0.126 | 0.140 | 0.122 | 0.091 | 0.116 | 0.252 | |
| Year 8 | 0.127 | 0.141 | 0.123 | 0.091 | 0.117 | 0.254 | |
| Year 9 | 0.128 | 0.142 | 0.124 | 0.092 | 0.117 | 0.255 | |
| Year 10 | 0.129 | 0.142 | 0.124 | 0.093 | 0.118 | 0.256 | |
| Year 11 | 0.130 | 0.143 | 0.125 | 0.093 | 0.118 | 0.258 | |
| Year 12 | 0.131 | 0.144 | 0.126 | 0.094 | 0.119 | 0.259 | |
| Year 13 | 0.132 | 0.145 | 0.126 | 0.095 | 0.120 | 0.260 | |
| Year 14 | 0.133 | 0.145 | 0.127 | 0.096 | 0.120 | 0.262 | |
| Year 15 | 0.135 | 0.146 | 0.128 | 0.097 | 0.121 | 0.263 | |
| Year 16 | 0.136 | 0.147 | 0.128 | NA | 0.122 | 0.265 | |
| Year 17 | 0.137 | 0.148 | 0.129 | NA | 0.122 | 0.266 | |
| Year 18 | 0.138 | 0.149 | 0.130 | NA | 0.123 | 0.268 | |
| Year 19 | 0.140 | 0.149 | 0.131 | NA | 0.124 | 0.269 | |
| Year 20 | 0.141 | 0.150 | 0.131 | NA | 0.124 | 0.271 | |

## B. Market-Based Mechanism

Section 8005a(f)(1) requires that the Board, for new standard-offer projects:

> use a market-based mechanism, such as a reverse auction or other procurement tool, to obtain up to the authorized amount of a category of renewable energy, if it first finds that use of the mechanism is consistent with:
> (A) applicable federal law; and
> (B) the goal of timely development at the lowest feasible cost.

28. For all categories except solar PV, 30 percent of the cost increases by 1.6% each year to reflect the impact of inflation on operating and maintenance expenses. Docket 7533, Order of 1/15/10 at 21-22; Docket 7780, Order of 1/23/12.

The development of a market-based mechanism pursuant to Sections 8005a(f)(1) is addressed below.

**(1) Use of Market-Based Mechanism**

Participants' Comments

REV and Triland support the continuance of the existing standard-offer structure and contend that a market-based mechanism is not consistent with the Section 8005(f)(1) "goal of timely development at the lowest feasible cost."[29] REV claims that a market-based mechanism, including a Request For Proposal ("RFP") mechanism, will increase complexity and costs for a very limited program size, decreasing competitiveness and resulting in very few projects being developed in a timely manner, and therefore failing to comply with the statute.[30] REV contends that while RFPs may work in other scenarios and examples, there is considerable concern regarding the approach for the initial 5 MW of annual program capacity. REV claims the success of the RFP mechanism in California does not apply to Vermont because California established a program with a very different size and scope, adopting requirements for a minimum project size (1.5 MW) and large program cap (850.75 MW in 2009 and 281.73 MW in 2010).[31] In addition, REV claims that there are numerous examples of other states in which RFP models were not successful in ensuring projects were built.[32]

The Department, BED, GMP, IBM, VEC, VEPP Inc., and VPPSA support the use of a market-based mechanism, specifically an RFP mechanism, and contend that a market-based mechanism is consistent with the requirements of Section 8005a(f)(1).[33]

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29. REV Comments of 12/18/12 at 1-2; Triland Comments of 1/18/13 at 1.

30. REV Comments of 12/18/12 at 2; REV Comments of 1/21/13 at 1; REV Comments of 1/31/13 at 1.

31. REV Comments of 12/18/12 at 1-2.

32. REV Comments of 1/31/13 at 1.

33. Department Comments of 1/31/13 at 1; BED/VEC Comments of 1/18/13 at 1; GMP Comments of 1/18/13 at 1-2; IBM Comments of 1/31/13 at 1; VPPSA Comments of 1/18/13 at 1; VEPP Inc. Comments of 1/18/13 at 1.

The Department asserts that a market-based mechanism will facilitate competition and help ensure that the State is encouraging standard-offer projects at the lowest feasible cost. The Department contends that no evidence has been provided which demonstrates that the "goal of timely development" will be impeded by an RFP mechanism. The Department asserts that the changes to the standard-offer program, such as increased deposits and reduced commissioning time (for solar PV), will likely aid and encourage timely development of projects. The Department further contends that an RFP, with mandatory requirements for entry, will facilitate proposals for projects with a greater likelihood of success than might be experienced with projects selected by lottery, a selection mechanism that may be used under the continuance of the existing standard-offer structure.[34]

BED and VEC argue that using net project cost as a determinant for acceptance into the standard-offer program is in the best interest of the end-use customer and more consistent with least-cost planning principles than a random lottery selection or other arbitrary process such as first-in first-selected. BED and VEC contend that if, over time, there is sufficient evidence that the RFP process is not effective then the mechanism can be revisited in future years.[35]

Discussion and Conclusions

Section 8005a(f)(1) requires that the Board use a market-based mechanism for new standard-offer projects, if it first finds that use of the mechanism is consistent with applicable federal law and the goal of timely development at the lowest feasible cost.

As we discussed above, the standard-offer program, which establishes prices for each renewable category of generation based upon the avoided cost of such projects is consistent with federal law. Similarly, the use of a market-based mechanism, if it is reasonably implemented is consistent with federal law. The primary difference between the two approaches is that the standard-offer approach establishes a single avoided cost, whereas the market-based approach allows each generation facility to bid to develop a project based upon its own cost structure,

34. Department Comments of 1/31/13 at 1.

35. BED/VEC Joint Comments of 1/18/13 at 1-2.

which may be lower than the generic avoided cost (and perhaps even a better reflection of the true avoided cost than the generic pricing). When backstopped with a cap on standard-offer prices set at the generic avoided cost, this approach is fully consistent with federal law.

We also find that adoption of a market-based mechanism, with conditions designed to encourage projects that are committed to construct the generation facilities, is consistent with the goal of timely development of standard-offer projects at the lowest feasible cost. The existing program has resulted in the deployment of new renewable generation projects. That system, as the Board has discussed in prior orders, required few financial commitments from developers, so entry into the program was easy. The result has been a number of projects exiting the program for failure to meet project development deadlines, which has slowed the overall deployment. A market-based mechanism, particularly with the conditions we adopt today, will encourage more well-planned projects. A developer will need to more rigorously assess its cost structure in preparing a bid. As a result, such developer is more likely to be positioned to successfully achieve commissioning of the project. Market-based mechanisms, such as the RFP approach we adopt in this Order, have been demonstrated in other states and jurisdictions to successfully implement renewable energy programs. And we see no evidence that the Board is likely to see bidders attempt to submit a below-cost bid (which could lead to increased drop-out and slower deployment).

Because the market-based mechanism is consistent with federal law and the goal of rapid deployment at lowest feasible cost, the Board is required to use a market-based mechanism to set standard-offer prices. In today's Order, we establish such a mechanism, specifically an RFP approach, with conditions set forth below. In addition, the standard-offer prices based on an avoided cost methodology that we adopted above will serve as caps on the prices solicited through the market-based mechanism.

**(2) Request For Proposal Mechanism**

Participants' Comments

Power Advisory, with initial input from interested participants, developed a draft RFP.[36] The draft RFP was composed of four chapters: (1) introduction; (2) an overview of the RFP process, including schedule; (3) the evaluation process, including the mandatory requirements for proposal submittal and evaluation and proposal selection process; and (4) major terms and conditions of the RFP process. Participants were provided an opportunity to file comments on the draft RFP.

VPPSA, BED, and VEC support an RFP approach using price as the only selection criteria.[37] VPPSA contends that the RFP approach will encourage competition among developers and will help ensure that standard-offer resources are built at the lowest cost to ratepayers. VPPSA also contends that a streamlined RFP process may help keep the administrative costs of the program low.[38]

The Department, GMP, and IBM recommend that the evaluation of RFP proposals for the development of new standard-offer plants should be based on an effort to understand the value that the plant can provide for the benefit of Vermont utility consumers.[39] Under this approach, projects are ranked in descending order of benefit-cost ratios and then selected in order until the annual cap is filled.[40]

The Department and GMP assert that a value-based approach is consistent with least-cost planning principles identified in Sections 202a and 218c and produces the most value possible

36. Draft Request for Proposals for Standard Offer Eligible Projects, January 25, 2013. The participants to this docket also considered adoption of an auction mechanism to implement the market-based approach. After discussion, participants concluded that the RFP was preferable. Two primary factors weighed in this decision: the small size of the block of power available in 2013 under the statute and the complexity of designing and implementing an auction, particularly considering the size of the block of power.

37. BED/VEC Comments of 1/18/13 at 4.

38. VPPSA Comments of 1/18/13 at 1.

39. Department Comments of 1/31/13 at 1; GMP Comments of 1/31/13 at 1-2; IBM Comments of 1/31/13 at 1-2.

40. GMP Comments of 1/31/13 at 2.

for ratepayers.[41] The Department further contends that the value-based mechanism supports the goals identified in Section 8001(a), including the goals of reducing rate impacts, reducing environmental impacts associated with greenhouse gas emissions, and encouraging support and incentives to locate renewable energy plants in a manner to provide benefit to the operation and management of the grid, reduce line losses, and address transmission and distribution ("T&D") constraints.

GMP recommends that stakeholders be afforded an opportunity to review and comment on the evaluation of results under an RFP process, with the ultimate selection of projects to be awarded standard-offer contracts made by the Board after which the Board would direct the SPEED Facilitator to award contracts to the selected plants. GMP further recommends that the RFP: (1) allow developers with existing standard-offer contracts to bid new projects into the RFP; (2) require that the project description include the AC plant rating (net power delivered to the grid at a specific delivery point); and (3) clarify that disputes are subject to resolution by the Board and that the discretion of the SPEED Facilitator is limited.[42]

While not supporting an RFP mechanism, REV provided comments on the draft RFP.[43] REV did not support the use of a benefit test in the RFP process to determine which projects will be selected for the programmatic cap. REV contends that a requirement for proposal security is unnecessary and will create additional work and increase the cost of administrating the RFP. REV further argues that security payment should be required only upon execution of the standard-offer contract. REV recommends that the RFP section on proposal organization should include only the location of the project and rated AC capacity. REV supports the requirement for proponent team experience, but suggests that the RFP be re-worded to ensure and allow for flexibility in the event that individuals of the team may change. REV also recommends that the RFP be re-worded to reflect that the SPEED Facilitator will accept proposals that substantially comply with the RFP.

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41. Department Comments of 1/31/13 at 2-4.

42. GMP Comments of 1/18/13 at 2-3.

43. REV Comments of 1/21/13 at 1-2; REV Comments of 1/31/13 at 1-2.

If a market-based mechanism is employed, Triland recommends that the RFP incorporate the following: (1) projects are selected on the basis of lowest price only with ties decided by a non-subjective process such as a computerized lottery mechanism; (2) no deposit is required at the time of submission of a bid; (3) if a waiting list is formed, then projects are required to submit a $10 per kW deposit; (4) to address the risk and expense of the permitting process, projects are allowed to be refunded 100 percent of the deposit up to 12 months from execution of the standard-offer contract; (5) an individual is allowed to submit multiple bids and be awarded multiple contracts based on a lowest-price bid process; and (6) an attempt should be made to include projects from each technology each year.[44]

VEPP Inc. made recommendations for additional and clarifying language to the following sections of the RFP: schedule, confidentiality, proposal organization, project team experience, and reserved rights. VEPP Inc. also recommends that a letter of credit not be included as an option for satisfying proposal security given the administrative burden for validating a letter of credit. VEPP Inc. suggests that the conditions in the standard-offer contract under which the deposit is refundable in the first year be reconsidered in order to encourage realistic bidding. In addition, VEPP Inc. suggests that a minimum bid be identified (e.g., 20 percent less than the avoided costs established by the Board) to ensure realistic bidding. VEPP Inc. also recommends that a small capacity set aside be established for projects less than 150 kW.[45]

Discussion and Conclusions

Section 8005a(f)(1) requires that the Board use a market-based mechanism to establish prices for new standard-offer projects. Section 8005a(c)(1) requires that the Board annually, commencing April 1, 2013, increase the cumulative plant capacity of the standard-offer program until the 127.5 MW programmatic cap is reached. For the first three years of the program, the

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44. Triland Comments of 1/18/13 at 1-2.

45. VEPP Inc. Comments of 1/31/13 at 1-3.

incremental capacity is 5 MW per year, plus any additional capacity remaining from previous years (due to projects dropping out of the program).[46]

In today's Order, we are establishing an RFP mechanism to determine the standard-offer projects that will fill the programmatic cap. The RFP, to be used by the SPEED Facilitator to solicit projects, starting on April 1, 2013, is contained in Attachment I to this Order.

Participants, not withstanding REV's opposition to a market-based mechanism, generally agreed that an RFP represented an appropriate mechanism to serve the 2013 programmatic cap of approximately 5 MW. Power Advisory worked with participants to develop a draft RFP, but was unable to obtain full resolution on all issues. We address the RFP issues requiring resolution below. Editorial and minor changes recommended by participants were directly incorporated into the RFP contained in Attachment I to this Order.

Participants disagree on how projects should be selected under the RFP approach, with the Department, GMP, and IBM advocating for a value-based approach and BED, VEC, and VPSSA advocating for a price-ranking approach. We conclude that, at this time, standard-offer projects should be selected on the price offered, with the projects ranked from lowest to highest price, until the award group fills the available cap. Selection based on price will encourage competition among developers and will help ensure that standard-offer resources are built at the lowest cost to ratepayers.[47] More importantly, the approach results in a transparent process that is straightforward to implement.

In reaching this conclusion, we recognize the potential benefits of the value-based approach favored by some parties. However, these parties have not yet been able to develop a system for valuing projects that is transparent. At this stage, we conclude that it is more important that the RFP process be transparent. It is possible that, in the future, the proponents of the value-based approach can develop a mechanism for incorporating value directly into the price

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46. For the first three years, approximately 500 kW of each year's incremental capacity is reserved for the provider block.

47. The value-based approach may also meet this goal, if one views "lowest cost" to include all costs to ratepayers, including otherwise unpriced costs and benefits. For example, a project with a higher bid price that results in lower line losses in a particular area may actually have a lower effective cost to Vermont consumers. We understand that the value-based approach attempts to incorporate these harder-to-quantify aspects.

comparisons. Or, after experience, we may conclude that the likely judgment calls are acceptable because the result is of greater benefit to Vermont ratepayers. We decline to adopt such an approach at the outset of the RFP process, but will continue to convene discussions to attempt further refinement.

Under the RFP process, projects will be selected until the award group fills the available capacity in the cap (approximately 4.5 MW for the 2013 capacity cap). Although there is an annual cap on the award group, once the cap is approached, the SPEED Facilitator is not required to reject the next project in the bid list because the project would exceed the cap. Instead that project will be accepted into the program, and the following year's capacity solicitation will be reduced by the amount of extra capacity that was contracted. This process will facilitate the goal of timely development. Since 2.2 MW is the maximum project size eligible for the standard-offer program, there is a limit to the extent any single project can exceed the annual cap.

Some participants supported the requirement for proposal security,[48] although REV and Triland opposed it, asserting that proposal security was unnecessary or should be refundable. We conclude that proposal security will encourage legitimate and realistic bidding during the RFP process and is more likely to result in the timely development of projects. One of the issues that we identified in the Docket 7780 pricing determination was that the completely refundable deposit allowed easy entry, but also allowed projects that had not been well-developed to obtain standard-offer contracts. The Board has partially addressed this issue through changes to the deposit provisions, limiting refunding under certain conditions. However, as the Board implements an RFP process, it is important to ensure that low bidders have done an appropriate examination of their cost structures and the feasibility of project development. An added proposal security should encourage bids by projects that have done such an examination. Needless to say, having performed greater investigation, the projects are more likely to be constructed rapidly. Accordingly, we are requiring that bidders pay a proposal security of $10 per kW of installed AC capacity. The proposal security will be refundable upon commissioning

48. Proposal security is a deposit paid to the SPEED Facilitator at the time the bid is submitted in an amount specified in $ per kW of installed AC capacity.

of a standard-offer project, further encouraging the developers to rapidly move towards deployment.

The existing standard-offer contract requires a refundable deposit (under certain circumstances) of $25 per kW. By April 1, 2013, before the issuance of the RFP, we will amend the standard-offer contract to require a $15 per kW refundable (under certain conditions) deposit, to reflect that standard-offer projects will be required to pay a proposal security under the RFP process.

REV and Triland claim that a demonstration of project site control is not necessary to ensure legitimate RFP bidding. We conclude that project site control will encourage realistic bidding during the RFP process and will likely result in the timely development of projects. In addition, project site control is already required to execute a standard-offer contract. Accordingly, we are requiring each RFP bidder to demonstrate project site control by providing evidence of one of the following: (1) fee simple title to such real property; (2) valid written leasehold interest for such real property; (3) a valid written option, exercisable unconditionally by the Proponent or its assignee, to purchase or lease such real property; or (4) a duly executed contract for the purchase or lease of such real property.

Some participants supported the mandatory requirement that an RFP bidder demonstrate experience in developing, financing, and constructing renewable energy projects. We are not convinced that project team experience is essential and we will not make it a requirement of the RFP. Proposal security and site control should encourage legitimate and realistic bidding and timely development of projects. In addition, the determination of experience is a subjective criteria that may result in a less than transparent process and may result in the need for dispute resolution by the Board during the RFP process.

In this Order, we establish an RFP mechanism to determine the standard-offer projects that will fill the programmatic cap, but we do not specify the details of how the SPEED Facilitator will issue the RFP. It is likely that the RFP will require advertising and outreach to prospective bidders. The details of this process will be worked out between the Board and the SPEED Facilitator prior to the issuance of the RFP and will be available at www.vermontspeed.com.

In order to meet the requirements of Section 8005a(c)(1), we direct the SPEED Facilitator to issue the RFP at 9 a.m., on April 1, 2013, unless the Board establishes a different issue date due to unforeseen implementation or other issues that require additional time for resolution. Upon completion of the proposal selection process, and five days prior to the announcement of the award group, the SPEED Facilitator will provide to the Board the results of the award group under the RFP, with the recommendation that the Board authorize the Facilitator to enter into contracts with such facilities.

**(3) Reserve and Waiting List**

Participants' Comments

The Department recommends that a reserve capacity be created from the projects that bid into the RFP but were not selected as part of the award group ("Reserve"). The Department contends that a Reserve will facilitate the goal of timely development of standard-offer projects by ensuring that if a project is withdrawn following its selection, another project may be selected immediately. The Department recommends that the Reserve be utilized only until January 1st (for 9 months following solicitation), with any unused capacity created by project withdrawal between January 1st and April 1st rolled into the next annual solicitation on April 1st. The Department further recommends that projects that are withdrawn between January 1st and April 1st of a calendar year should not be eligible for participation in the next immediate solicitation.[49]

GMP recommends that any reserve queue or waiting list developed after the initial RFP awards does not carry forward into subsequent solicitation periods.[50] VEC supports a waiting list of 6 months for projects selected in the RFP process.[51] REV recommends the creation of a Reserve of an additional 50 percent of the annual MW allocation. REV also recommends that

49. Department Comments of 1/31/13 at 5-6.

50. GMP Comments of 1/18/13 at 2-3.

51. VEC Comments of 1/31/13 at 3.

developers be required to decide whether they would prefer to remain in the Reserve or participate in the next April 1 solicitation.[52]

The Department recommends that the current waiting list for the standard-offer program should not be used once the new process for selecting projects has been approved by the Board, and that projects that were on the waiting list should have no special rights regarding participation in the new selection mechanism. The Department argues that treating all potential projects equally, once the new requirements are in effect, helps to ensure that ratepayers pay the lowest ultimate cost as updated costs are developed. The Department recommends that the current waiting list cease to be used after March 1 (when the Board is required to issue new program parameters). If capacity becomes available between March 1 and April 1, when the solicitation occurs, then that capacity should be rolled into the April 1 RFP solicitation.[53]

Triland recommends that the existing waiting list be kept activated until the initial 50 MW cap is completed. Triland argues that there are viable projects on the waiting list that have incurred on-going option and engineering expenses in good faith and in anticipation of fulfilling the need for timely development; de-activating the waiting list before the initial 50 MW cap is commissioned is an unfair and unnecessary burden to place on those projects (and developers).[54]

IBM supports replacing the existing waiting list at the start of the RFP process.[55]

Discussion and Conclusions

Pursuant to Section 8005a(c), the Board is required to issue standard offers to new renewable plants until a cumulative capacity amount of 127.5 MW is reached. Under the Statute, the 127.5 MW cap includes 50 MW of capacity previously authorized under the standard-offer program. The new 77.5 MW portion of the programmatic cap is distributed in annual amounts of

52. REV Comments of 1/21/13 at 1-2.

53. Department Comments of 1/31/13 at 6-7.

54. Triland Comments of 1/18/13 at 2.

55. IBM Comments of 1/31/13 at 2-3.

5 MW for the three years (2013-2015), 7.5 MW for the three years (2016-2018), and 10 MW for the remaining years of the program (2019-2020). The annual amount is decreased each year by the provider block and GHG reduction credits. Section 8005a(c)(1)(B)(iii) does not specifically address the status of unused capacity within the initial 50 MW; however, it does make clear that, going forward, any unsubscribed capacity within the independent developer block is added to the annual increase for each following year until that capacity is subscribed.

Participants supported creating a reserve of capacity from the projects that bid into the RFP but were not selected as part of the award group. We are persuaded that a Reserve will facilitate the goal of timely development of standard-offer projects by ensuring that if a project is withdrawn following its selection, another project may be contracted immediately. Accordingly, a Reserve of 4.5 MW will be created from the proposals with the lowest price that were not part of the initial RFP award group. The Reserve will be available only until January 1st of each year, with any unused capacity created by project withdrawal between January 1st and April 1st rolled into the next annual solicitation on April 1st. Projects that are withdrawn between January 1st and April 1st of a calendar year will not be eligible for participation in the next immediate solicitation. The proposal security will be refundable to projects that drop out of the reserve list before January 1st.

The standard-offer program currently maintains a waiting list for any unused portion of the initial 50 MW program cap. Triland recommends that the waiting list be maintained, while other participants recommend that the waiting list be ended, with any unused capacity rolled into the RFP solicitation process. We are convinced that ending the current waiting list will encourage timely development of standard-offer projects at the lowest feasible cost. Projects on the current list will be eligible to participate in the April 1, 2013, RFP. Accordingly, the current waiting list for the standard-offer program will cease on March 1, 2013. If capacity becomes available between March 1 and April 1, 2013, then the SPEED Facilitator will include that capacity in the April 1, 2013, RFP solicitation.

## IV. Programmatic Issues

### A. Technology Allocation

Upon establishing the standard-offer program, the Board determined that no one technology should fill more than 25 percent of the initial project queue and required that such "technology caps" be reviewed after an initial six-month trial period.[56] After the six-month trial period, the Board extended the technology caps through October 31, 2010,[57] and then again extended the technology caps through May 31, 2011.[58] However, in June 2011, the Board elected not to extend the technology caps and directed the SPEED Facilitator to admit projects on an alternating basis from the solar PV and wind waiting lists, beginning with the solar PV waiting list until the program was fully subscribed. This determination was made, at least in part, because there was unsubscribed capacity due to the technology caps, which was impeding the rapid deployment required by the statute.

Section 8005a(c)(2) includes the following new directive with regard to technology allocations:

> The board shall allocate the 127.5-MW cumulative plant capacity of this subsection among different categories of renewable energy technologies. These categories shall include at least each of the following: methane derived from a landfill; solar power; wind power with a plant capacity of 100 kW or less; wind power with a plant capacity greater than 100 kW; hydroelectric power; and biomass power using a fuel other than methane derived from an agricultural operation or landfill.

Participants' Comments

The Department, GMP, and IBM recommend that the technology allocations be applied to the total 127.5 MW of capacity, rather than to the annual available capacity.[59] The Department states that imposing allocations across numerous technologies in each annual

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56. Docket 7533, Order of 9/30/09 at 15.

57. Docket 7533, Order of 6/24/10 at 4.

58. Docket 7533, Order of 10/29/10 at 4.

59. Department Comments of 1/31/13 at 4; Department Comments of 9/20/12 at 8-9; GMP Comments of 9/20/12 at 3-4; IBM Comments of 9/20/12 at 5.

capacity increase is likely to lead to program inefficiencies, create stranded capacity mismatched with the range of technologies proposed in a given year, and potentially discourage participation in an RFP process.[60]

The Department recommends that the Board wait to determine the technology allocations until after at least two to three years of operation of the redesigned standard-offer program[61] and GMP supports allowing for some flexibility to modify the allocations over time.[62] IBM recommends that each technology initially be allocated a minimum amount of the total capacity, with the remaining balance of the total 127.5 MW of capacity allocated to the technologies that are most cost effective and most consistent with utility least-cost planning principles.[63]

The Department and GMP also advocate considering several factors in determining the technology allocations, including: (1) the relative size of the resources which can reasonably be expected to be developed in Vermont; (2) market interest in developing each type of technology in the state; (3) expected net costs for each technology relative to benefits from avoided energy, capacity, renewable energy credits ("RECs"), and other resources; (4) the relative operating characteristics of the individual generating technologies; and (5) the integration with committed and planned supply portfolios within the utility least-cost planning rubric.[64]

Alternatively, VEPP Inc. recommends that the technology allocations be applied annually by grouping technologies with similar avoided costs into two groups and then splitting each year's annual available capacity between those two groups.[65] VEPP Inc. asserts that this

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60. Department Comments of 1/31/13 at 4; Department Comments of 9/20/12 at 8-9.

61. Department Comments of 1/31/13 at 4.

62. GMP Comments of 9/20/12 at 3-4.

63. IBM Comments of 9/20/12 at 5.

64. Department Comments of 1/31/13 at 4; GMP Comments of 9/20/12 at 3-4.

65. VEPP Inc. Comments of 9/20/12 at 6-7.

For example, in the first year, the 5 MW capacity increase to the Standard Offer Program would be divided into two categories of 2.5 MW. The first category would include solar and small wind based on comparable pricing in the $0.24-$0.27/kWh range. The second category would include large wind, biomass, hydro, and landfill gas based on comparable pricing in the $0.09-$0.12/kWh range. A market-based mechanism, if authorized by the Board, could be used to select projects from within each group of technologies. If there is any unused capacity remaining in either approach will address the resource-constrained nature of technologies such as landfill gas methane, help to level the playing field for projects with disparate avoided costs in a market-based system, and allow projects with long development lead times, such as hydroelectric facilities, to have assurance that there will be available capacity for their projects in the future.[66]

Discussion and Conclusion

IBM, GMP, and the Department support establishing technology allocations based on the cumulative 127.5 MW capacity of the standard-offer program. VEPP Inc. supports establishing technology allocations for each annual increment of the total program capacity.

We agree with the participants that the statutory mandate for technology allocations can be applied over the entire 127.5 MW capacity of the program. Establishing technology allocations on this basis will promote diversity of renewable projects, consistent with the legislative intent. By contrast, imposing technology allocations across numerous technologies for each year's available capacity would likely lead to program inefficiencies and create stranded capacity mismatched with the range of technologies proposed in a given year. We do not establish the technology allocations now, however. Recent experience has shown that renewable development under the standard-offer program is heavily weighted to one technology, solar PV. Establishing the caps now could either cause the program to be weighted to certain technologies, or end up risking idle capacity that may be reserved for technologies for which viable projects are not proposed.

We also agree with IBM's recommendation that a minimum amount of the cumulative capacity of the program should be set aside for each of the statutorily identified technologies, pursuant to Section 8005a(c)(2).[67] We do not set that minimum at the present time. Instead, we

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grouping, a second offering can be held 6 months later, which is not subject to the technology allocation.

66. VEPP Inc. Comments of 9/20/12 at 6-7.

67. Methane derived from a landfill; solar power; wind power with a plant capacity of 100 kW or less; wind power with a plant capacity greater than 100 kW; hydroelectric power; and biomass power using a fuel other than methane derived from an agricultural operation or landfill.

are persuaded by the Department's recommendation to wait for the redesigned standard-offer program to be implemented before establishing such minimums.

We intend to review the outcome of the 2013 RFP processes and open a proceeding to further investigate this issue immediately following the 2013 RFP process. During this investigation, the Board may consider several factors, including: (1) the total capacity of each technology already granted standard-offer contracts; (2) the relative size of the technology resources which can reasonably be expected to be developed in Vermont; (3) market interest in developing each type of technology in the state; (4) the relative operating characteristics of the individual generating technologies; and (5) the integration with committed and planned supply portfolios within the utility least-cost planning rubric.

**B. Provider Block**

Section 8005a(c)(1)(B) requires that a portion of each annual increase shall be made available to projects proposed by Vermont retail electric utilities. This portion is referred to as the "Provider Block." Section 8005a(c)(1)(B) provides the following directives regarding the Provider Block:

> (B) *Blocks*. Each year, a portion of the annual increase shall be reserved for new standard offer plants proposed by Vermont retail electricity providers (the provider block), and the remainder shall be reserved for new standard offer plants proposed by persons who are not providers (the independent developer block).
>
> (i) The portion of the annual increase reserved for the provider block shall be 10 percent for the three years commencing April 1, 2013, 15 percent for the three years commencing April 1, 2016, and 20 percent commencing April 1, 2019.
>
> (ii) If the provider block for a given year is not fully subscribed, any unsubscribed capacity within that block shall be added to the annual increase for each following year until that capacity is subscribed and shall be made available to new standard offer plants proposed by persons who are not providers.
>
> (iii) If the independent developer block for a given year is not fully subscribed, any unsubscribed capacity within that block shall be added to the annual increase for each following year until that capacity is subscribed and:

(I) shall be made available to new standard offer plants proposed by persons who are not providers; and

(II) may be made available to a provider following a written request and specific proposal submitted to and approved by the board.

In order to implement this new feature of the standard-offer program, this Order addresses the following issues: (1) the selection of projects within the Provider Block and the allocation of projects between the various distribution utilities; (2) the size of the Provider Block; (3) the price paid to such projects; and (4) the application of technology allocations to the Provider Block.

Participants' Comments

The Department states that providers' projects should be selected through a competitive solicitation process as part of the market-based pricing mechanism developed in this Docket. However, the Department recommends modifying the avoided-cost figures to reflect the capital structure specific to utilities. Finally, the Department states that some utilities may have an advantage in developing low-cost proposals due to differing capital structures and recommends that the Board should attempt to "level the playing field" so that all utilities can participate in the Provider Block on equal footing.[68]

VEC states that the Provider Block should be implemented in a way that results in the greatest net benefit to ratepayers. With this in mind, VEC believes that it is not necessary to allocate the small amount of available annual capacity within the Provider Block among the distribution utilities. Instead, VEC recommends that proposed projects should be ranked and selected based on the net benefits provided to end-use customers. VEC further contends that distribution utilities should be compensated on a "Cost-Plus" basis.[69] Finally, VEC recommends that distribution utilities should be able to receive a standard-offer contract for a portion of a

68. Department Comments of 12/21/12 at 2.

69. VEC Comments of 1/31/13 at 2.

proposed project.[70] For example, a utility could receive a standard-offer contract for a 500 kW portion of a 1.0 MW project.

GMP recommends that the Board initially adopt an RFP process for selecting projects in the Provider Block. GMP states that in future years, the Board may calibrate this process if the Board determines that the selection process is not providing sufficient geographic or service-territory diversity. GMP contends that there has not been enough consideration of whether the avoided-cost determinations made in Docket 7874 are appropriate for provider projects. GMP recommends that the Board should further investigate this issue through compliance filings from a working group of interested participants led by the Department so that the Board may determine avoided-cost figures that adequately reflect utility capital structures and available tax incentives.[71]

VPPSA would like to see the capacity within the Provider Block allocated among the distribution utilities according to their *pro rata* share of the state's retail electricity sales. Because these shares of capacity would likely be very small, VPPSA recommends that the Board permit utilities to aggregate their annual shares and "pre-build" projects ahead of the scheduled pace of deployment. Further, VPPSA contends that utilities should be permitted to collaborate on projects. With respect to pricing, VPPSA promotes a flexible, project-specific approach, limited by the technology-specific avoided-cost prices set by the Board.[72]

REV urges the Board to consider the full cost to the ratepayer when considering the prices for projects in the Provider Block. REV asserts that "because utilities are able to rate base projects, a portion of the cost remains 'hidden' to all ratepayers."[73] For this reason, REV believes that prices offered to utilities must represent the full cost to the ratepayer.

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70. VEC Comments of 1/31/13 at 2-3.

71. GMP Comments of 1/31/13 at 2-3.

72. VPPSA Comments of 1/31/13 at 1.

73. REV Comments of 12/21/12 at 1.

Discussion and Conclusions

*Selection of Projects Within the Provider Block*

Pursuant to Section 8005a(f), we have determined in this Order that a market-based pricing mechanism is both consistent with federal law and likely to ensure the goal of timely development at the lowest feasible cost. No party has presented any convincing rationale for treating utility projects differently from other developer-owned standard-offer projects. Accordingly, projects within the Provider Block will be selected according to the RFP process described above and in the attachment to this Order. Projects will be selected based on the price per kWh until the capacity of the Provider Block is filled.[74] As suggested by some participants, utilities are free to collaborate on a project in order to produce a more competitive proposal.

In reaching the conclusion that the provider block should be allocated in the same manner as the developer block, we decline to accept VPPSA's recommendation for allocating the capacity within the Provider Block according to each utility's *pro rata* share of the state's retail electric sales. Section 8005a(c)(1)(B)(iii) sets forth a deliberate pace for deploying capacity in the Provider Block. In contrast, VPPSA's recommendation relies on allocating the total Provider Block capacity authorized for the next ten years and then allowing each utility to "pre-build" their allotted capacity — in essence accelerating the pace of deployment. While "pre-building" might advance the goal of rapid deployment, such a process is contrary to the intent of Section 8005a(c)(1)(B)(iii), which limits the amount of capacity for each year to as little as 500 kW. Accordingly, we find no basis to adopt VPPSA's recommendation.

*Annual Size of the Provider Block*

The following table sets forth the estimated capacity available within the Provider Block for each of the next nine years.[75]

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74. If the last project selected to fill the capacity in the Provider Block exceeds the total annual increase in capacity for that year's RFP, the excess capacity will be taken from the following year's annual increase.

75. The statute sets the size of the Provider Block as a percent of the total annual increase for that year. Accordingly, the actual size of the Provider Block may vary.

| Years | Approximate Provider Block Capacity |
|---|---|
| 2013 - 2015 | 0.5 MW |
| 2016 - 2018 | 1.125 MW |
| 2019 - end of program | 2.0 MW |
| **Total** | 12.875 MW |

Further, Section 8005a(c)(1)(B)(ii) states:

> If the provider block for a given year is not fully subscribed, any unsubscribed capacity within that block shall be added to the annual increase for each following year until that capacity is subscribed and shall be made available to new standard offer plants proposed by persons who are not providers.

This language makes clear that any unsubscribed capacity in the Provider Block from a given year will be added to the increase in capacity for the next year and is available to persons who are not providers. What is less clear is whether the excess capacity is exclusively available to persons who are not providers. We have developed the following procedure with the goal of simplicity and consistency with the statute. In the event that there is unsubscribed capacity from the Provider Block in any given year, that capacity will be included in the following year's annual increase, which means that the majority of that capacity will accrue to the Developer Block, though a percentage will be included in the Provider Block, as set forth in Section 8005a(c)(1)(B)(i).

*Price Paid to Providers*

The price paid to projects within the Provider Block will be set by the RFP process described in this Order. In all cases, the price will be no higher than the avoided cost for the proposed technology set in this proceeding. We received several comments regarding prices for provider projects. These comments raised additional issues, which we address below.

VEC recommends that providers be paid on a "cost-plus" basis. VEC does not indicate how this is authorized under the statute. Section 8005a(f) clearly states that the price paid under a standard-offer contract shall be either set by a market-based mechanism or the avoided cost.

Unlike the previous version of the standard-offer program (whereby utility projects served to reduce the cap but were not paid the standard-offer price), the new criteria in Section 8005a make no distinction between utility and developer projects in terms of the pricing. Accordingly, we find no basis in the statute to adopt VEC's recommendation.

GMP and the Department recommend that we adjust the avoided costs to reflect the capital structure and tax consequences specific to utilities. GMP proposes that a working group, led by the Department, develop a proposal for avoided costs and submit such a proposal as a compliance filing in this docket.

Section 8005a(f)(3) states that:

> The board shall take all actions necessary to determine the pricing mechanism and implement the pricing requirements of this subsection (f) no later than March 1, 2013 for effect on April 1, 2013.

Given the short amount of time between the date of this Order and April 1, 2013, we conclude that it is not practicable to develop separate technology-specific avoided-cost figures that could be implemented in the first round of the RFP. Furthermore, no participant has alleged that the avoided-cost figures already developed in this proceeding are either insufficient to induce providers to participate in the program or so high as to represent a windfall to the providers. Therefore, we find no compelling reason to hastily adopt utility-specific avoided-cost figures at this time. Section 8005a(f)(3) also provides, however, that annually the Board:

> shall review the [avoided cost] determinations previously made under this subsection to decide whether they should be modified in any respect in order to achieve the goal and requirements of this subsection.

Accordingly, the Board will open an investigation to determine avoided-cost figures applicable to utilities. These figures will be implemented in the 2014 RFP. For the time being, the price paid to projects within the Provider Block shall be the price bid into the RFP, and no higher than the avoided cost for the proposed technology set in this proceeding.

REV submitted comments expressing concern about the ability of providers to "hide" project costs in rates. We understand REV's concerns but believe they are easily addressed. All capital costs and operating expenses associated with a project that accepts a standard-offer must be booked below-the-line and are not added to rate base or eligible for recovery as an expense. Under the standard-offer contract, the SPEED Facilitator will pay the provider for all kWhs produced at the contract price. The contract price is the price bid by the provider in the RFP, and, at a maximum, the avoided cost developed in this proceeding. This price includes a rate of return that is intended to induce distribution utilities to propose and develop projects at the lowest feasible cost. The avoided cost also includes all expenses associated with the project, including the development costs and on-going operation and maintenance expense. Therefore, allowing a provider to earn an additional rate of return on the capital investment or to recoup operational costs would result in a windfall to the provider and result in ratepayers paying the same costs twice. This is not appropriate. Accordingly, capital investment or operational costs associated with a project may not be included in a utility's rates.

The provider of a standard-offer project still must purchase its *pro rata* share of the power produced in the standard-offer program from the SPEED Facilitator, which would include a portion of the power produced by the provider's own project. These costs would appropriately be included in the provider's rates as a cost of power in the same manner as other standard-offer projects allocated by the SPEED Facilitator to utilities. A provider must recoup these power costs to receive full recovery of its costs of doing business. However, as these costs are an expense, the provider will not recover a return on them. Thus, the concerns raised by REV that utilities can hide costs in their rates is without foundation. In summary, providers will realize a return on their projects through payment of the contract price from the SPEED Facilitator while the costs of power purchased by the provider from the standard-offer program may be recouped in rates.

*Technology Allocations and the Provider Block*

Similar to our discussion regarding the RFP generally, the initial year of the Provider Block will not be subject to any technology allocation. The Board will revisit the issue of technology allocation following the 2013 RFP process.

**C. Plants Outside Cumulative Capacity**

Section 8005a(d) requires that certain categories of plants "shall not count toward the cumulative capacity amount of subsection (c) of this section, and the board shall make standard offers available to them provided that they are otherwise eligible for such offers under this section" including those identified in Section 8005a(d)(2):

> New standard offer plants that the board determines will have sufficient benefits to the operation and management of the electric grid or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit.

In order to identify eligible plants, pursuant to Section 8005a(d)(2)(A), the Board must develop by March 1, 2013, "a screening framework or guidelines that will provide developers with adequate information regarding constrained areas in which generation having particular characteristics is reasonably likely to provide sufficient benefit to allow the generation to qualify for eligibility under this subdivision." Pursuant to Section 8005a(d)(2)(B), the Board must "require Vermont transmission and retail electricity providers to make the necessary information publically available in a timely manner, with updates at least annually." Section 8005a(d)(2)(C) requires that nothing in Section 8005a(d)(2) shall require the disclosure of information in contravention of federal law.

Two stakeholder working groups were formed to address the implementation issues arising from Section 8005a(d)(2). Stakeholder "Working Group A" was given the following tasks: (1) identifying areas of transmission, sub-transmission, and distribution systems that have reliability constraints that could be affected by additional load, and the forecasted need dates; (2) identifying the "wires" solution and providing an estimated cost of that solution; (3) describing the performance characteristics that any solution must meet in order to satisfy the appropriate reliability criteria (the "equivalence"); (4) identifying the geographic areas where generation or load reduction could defer or avoid the wires solution and estimating the quantity of generation or load reduction necessary to effectively address the reliability constraint; and (5) quantifying the amount of energy efficiency potential in the targeted area that is not already incorporated in the controlling forecast. Stakeholder "Working Group B" was given the following tasks: (1) identifying the performance characteristics of different renewable generation technologies; (2) identifying how the diverse performance characteristics relate to the equivalencies described by Working Group A; and (3) recommending a test that the Board may employ in determining whether the benefits to the operation and management of the grid, or a provider's portion thereof, that a distributed generation project would provide are sufficient to warrant issuance of a standard-offer contract under Section 8005a(d)(2).

### (1) Category of Plants that May Provide Sufficient Benefit

Pursuant to Section 8005a(d)(2), the Board must make standard offers available to new standard-offer plants that the Board determines will have sufficient benefits to the operation and management of the electric grid or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit. Stakeholder positions regarding implementation of this subsection fall into two broad categories: (1) those that limit the category to projects that mitigate identified transmission and distribution constraints; and (2) those that expand the first category to also include projects that provide positive net benefits under a cost-benefit analysis, whether or not they are intended to mitigate identified transmission and distribution constraints. As a threshold matter the Board must determine which category of plants may provide sufficient benefits to the operation and management of the grid, and thus qualify for exemption from the 127.5-MW program capacity limit.

Participants' Comments on Interpretation of "Sufficient Benefit"

GMP contends that only those standard-offer projects that help to mitigate transmission and distribution constraints and provide benefits in the form of deferral or avoidance of transmission and distribution project costs may provide sufficient benefit as established under Section 8005a(d)(2). GMP asserts that this interpretation is consistent with the legislative intent and will yield greater value for ratepayers. GMP argues that a broader interpretation of sufficient benefits that would exempt from the cap all projects that provide positive net benefits beyond a threshold level is not consistent with the legislative intent and has the potential to yield higher near-term retail rates. GMP states that this could also lead to some encroachment on utility portfolio management efforts.[76]

The Department contends that Section 8005a(d)(2) requires the Board to weigh the benefits and costs of any proposed standard-offer project when making a determination of

76. GMP Comments of 1/31/13 at 1.

whether a project should be exempted from the 127.5-MW program cap. The Department argues that if the benefits a project provides sufficiently outweigh the costs and include net benefits to the operation and management of the grid, even without value associated with a specific transmission or distribution infrastructure constraint, then the project developer should be offered a standard-offer contract and the associated project should be exempt from the cap. The Department asserts that all generation projects have an impact on the operation and management of the grid, and that even those that do not specifically address transmission and distribution constraints may offer other benefits, such as the provision of energy and capacity. The Department stresses that the first sentence of Section 8005a(d)(2), describing plants that shall be offered standard-offer contracts, includes a more general statement pertaining to the operation and management of the grid, and that the second sentence simply provides instruction to the Board and utilities to provide sufficient information regarding constraints.[77] Nonetheless, the Department supports limitation of the first year's implementation of Section 8005a(d)(2) to address known transmission and distribution constraints, and asserts that the standard-offer program should broaden its consideration of those plants that may provide sufficient benefits in subsequent years.[78]

BED contends that interpretation of Section 8005a(d)(2) should be limited. BED argues that the Department's broader interpretation of sufficient benefit would interfere with utility power supply planning, and could lead to increased retail rates and risk exposure.[79] BED and VEC contend that the Department's interpretation of sufficient benefit is too broad. BED and VEC state that Section 8005a(d)(2) refers to standard-offer projects that provide sufficient benefits to the operation and management of the electric grid. BED and VEC state that ISO New England defines the grid as the network of the transmission lines, substations, and associated equipment of an electric power system. BED and VEC argue that under this definition, a project must provide sufficient benefit to the operation and management of the network of transmission

77. Department Comments of 1/31/13 at 7-8.

78. Department Comments of 1/31/13 at 8.

79. BED Comments of 1/31/13 at 2-3.

lines, substations, and associated equipment of an electric power system in order to be exempted from the standard-offer program cap.[80]

IBM asserts that only projects that mitigate transmission and distribution constraints to an appreciable extent, based on an effectiveness factor, should be eligible for exclusion pursuant to Section 8005a(d).[81]

REV agrees with the Department's argument that the interpretation of sufficient benefit cannot be reduced solely to transmission and distribution constraints as per a plain reading of the statute, citing to language in Section 8005a(d)(2) allowing for consideration of "any other discernible benefit" provided by new standard-offer plants.[82] REV concurs with the Department's proposal that the initial development of sufficient benefit evaluation criteria should be modified as the Board and stakeholders gain experience with the implementation of Section 8005a(d)(2).

VELCO recommends that sufficient benefit must be grounded in the ability of a standard-offer plant to avoid the need for transmission system reinforcement to resolve a deficiency.[83]

VPPSA interprets sufficient benefits to relate to transmission and distribution deferrals, and contends that had the legislature intended to have all prospective standard-offer projects undergo a cost-benefit analysis, this would have been stated explicitly in the legislation. VPPSA contends that the Department's broad interpretation of sufficient benefits could obviate the programmatic cap that was put in place to set a reasonable boundary on the estimated impacts of standard-offer projects. VPPSA argues that such a broad interpretation would make it difficult for VPPSA to plan its power supply portfolio, and that it would likely have to either forego favorable contract opportunities in order to reserve space for additional standard-offer projects or

80. BED/VEC Joint Comments of 1/18/13 at 4.

81. IBM Comments of 1/31/13 at 2.

82. REV Comments of 1/31/13 at 3.

83. VELCO Comments of 9/20/12 at 4.

risk purchasing more energy than was needed to cover VPPSA member systems' loads, thus exposing ratepayers to avoidable market risk.[84]

Allco asserts that the term sufficient benefit implies that there should be a reasonable cost-benefit ratio.[85]

Discussion and Conclusion

Our interpretation of "sufficient benefit" is informed by considering Section 8005a(d)(2) in its entirety.[86] The first sentence of this subsection does not in itself explicitly limit consideration to those new standard-offer plants that would mitigate transmission and distribution constraints, but rather requires that standard-offer contracts shall be made available to "plants that the board determines will have sufficient benefits to the operation and management of the electric grid or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit." If Section 8005a(d)(2) ended here then it would be reasonable to interpret its meaning as applying to a broad array of potential projects. However, Section 8005a(d)(2) continues:

> . . . To enhance the ability of new standard offer plants to mitigate transmission and distribution constraints, the board shall require Vermont retail electricity providers and companies that own or operate electric transmission facilities within the state to make sufficient information concerning these constraints available to developers who propose new standard offer plants.
>
> (A) By March 1, 2013, the board shall develop a screening framework or guidelines that will provide developers with adequate information regarding constrained areas in which generation having particular characteristics is reasonably likely to provide sufficient benefit to allow the generation to qualify for eligibility under this subdivision (2).

84. VPPSA Comments of 1/18/13 at 2-3.

85. Allco Comments of 9/12/12 at 3.

86. The legislative "intent is most truly derived from a consideration of not only the particular statutory language, but from the entire enactment, its reason, purpose and consequences." *Lubinsky*, 148 Vt. at 50, 527 A.2d at 228; *see* also *In re Carroll*, 2007 VT 19, ¶ 9, 181 Vt. 383, 925 A.2d 990 (noting that legislative intent is determined by considering "the whole statute, the subject matter, its effects and consequences, and the reason and spirit of the law").

> (B) Once the board develops the screening framework or guidelines under subdivision (2)(A) of this subsection (d), the board shall require Vermont transmission and retail electricity providers to make the necessary information publically available in a timely manner, with updates at least annually.
>
> (C) Nothing in this subdivision shall require the disclosure of information in contravention of federal law.

Accordingly, we conclude that Section 8005a(d)(2) is properly interpreted as limiting consideration of plants that may provide sufficient benefits to the operation and management of the electric grid or a provider's portion thereof to those intended to mitigate transmission and distribution constraints, as opposed to those that provide more generalized benefits. This interpretation is consistent with the Vermont renewable energy goal of

> Providing support and incentives to locate renewable energy plants of small and moderate size in a manner that is distributed across the state's electric grid, including locating such plants in areas that will provide benefit to the operation and management of that grid through such means as reducing line losses and addressing transmission and distribution constraints.[87]

We observe that the interpretation of Section 8005a(d)(2) supported by the Department and REV could effectively eliminate the 127.5-MW cumulative capacity established in Section 8005a(c).

Having so defined the category of potential plants that may be considered to provide sufficient benefits, it is then appropriate to develop a screening framework and guidelines that will provide potential standard-offer plant developers with adequate information regarding constrained areas.

**(2) Screening Framework and Guidelines**

On January 11, 2013, GMP provided a "straw proposal" for discussion purposes outlining a potential screening framework and guideline to implement Section 8005a(d)(2) (the "Straw Proposal").[88] The Straw Proposal focuses on addressing bulk and predominantly bulk transmission constraints, and contemplates the use of existing VSPC processes, reporting

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87. 30 V.S.A. § 8001(a)(7).

88. This screening framework incorporates Board staff recommendations issued in an October 18, 2012, memorandum to stakeholders in response to stakeholder requests for guidance on particular issues.

mechanisms, public engagement activities, and subcommittees for the potential resolution of those constraints via non-transmission alternatives ("NTAs"), including standard-offer projects. Specifically, the Straw Proposal envisions that the VSPC processes will analyze any electric grid reliability gaps and make recommendations to the Board regarding the potential for NTAs to mitigate those reliability gaps. Subsequently, stakeholders would be afforded an opportunity to comment on the VSPC recommendations. The Board would then decide whether there are reliability gaps that should be addressed by new standard-offer plants, and if so, a new RFP would be issued.

Participants' Comments on Proposed Screening Framework and Guidelines

The Department largely agrees with the conceptual framework of the Straw Proposal, and offers several modifications in its comments.[89] The Department contends that the VSPC NTA Screening Tool should be modified, explicitly within the standard-offer context only, to eliminate question 4, which asks: "Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2.5 million?" The Department argues that screening a project out due to the small size of the infrastructure investment appears to conflict with the purpose and intent of Section 8005a(d)(2), and that smaller transmission and distribution projects may be where standard-offer projects can be most successful.[90]

GMP[91], BED, VEC[92], and VPPSA[93] support the process outlined in the Straw Proposal. GMP contends that the Straw Proposal: (1) builds upon the polices and procedures developed for the resolution of bulk and predominately bulk constraints; (2) identifies the procedures for determining the portion of any identified reliability gap to be cost-effectively addressed through standard-offer projects; and (3) provides a mechanism to compare NTA solutions and to develop

89. Department Comments of 1/31/13 at 12.

90. Department Comments of 1/31/13 at 14.

91. GMP Comments of 1/31/13 at 3.

92. BED/VEC Joint Comments of 1/18/13 at 2.

93. VPPSA Comments of 1/18/13 at 3-4.

a least-cost plan to address constraints. GMP asserts this is consistent with existing mechanisms and policies designed for such purposes. GMP contends that the Straw Proposal, when used in connection with an RFP, should help to select the best new standard-offer projects to mitigate constraints.[94] GMP maintains that the NTA Screening Tool should not be altered by eliminating the $2.5 million screening threshold. GMP contends that the Docket Nos. 7081 and 6290 screening tools were developed as a means to "allocate efficiently utility planning and engineering resources." Accordingly, GMP recommends that if the Board desires further consideration of this question then it should be evaluated within the context of those dockets in order to address the full range of issues and avoid unintended consequences.[95]

VPPSA asserts that the Straw Proposal places the procurement of standard-offer projects within the larger context of statewide planning efforts.[96]

REV does not support the Straw Proposal for multiple reasons. REV states that the Straw Proposal limits consideration to only those projects that provide transmission benefits while leaving consideration of distribution benefits to a future process. REV asserts that this limitation is inconsistent with a broad interpretation of the underlying statutory language regarding "sufficient benefits." REV asserts that the Straw Proposal exemplifies the lack of a level playing field between utility and non-utility developers – under the Straw Proposal utilities would define where there are transmission constraints, review proposed projects, and have the ability to submit their own projects. REV also contends that the Straw Proposal creates a significant conflict of interest by allowing utilities to bid their own projects into an RFP. Finally, REV asserts that the Straw Proposal will likely take multiple years to implement, which would not be "in keeping with addressing timely development."[97]

REV included in its comments an alternate proposal (the "REV Proposal"). Under the REV Proposal: (1) the SPEED Facilitator would administer the program; (2) the Board would

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94. GMP Comments of 1/31/13 at 3.

95. GMP Comments of 1/25/13 at 2-3.

96. VPPSA Comments of 1/18/13 at 3-4.

97. REV Comments of 1/21/13 at 2.

develop a screening framework to provide developers with information regarding constrained areas by March 1, 2013; and (3) the "uncapped" portion of the program would open on June 1, 2013, and would remain open on a rolling basis as information is made available. REV suggests that transmission constraints be identified by the VSPC and that projects be selected via a lottery process. REV suggests that distribution constraints be identified in utility Integrated Resource Plans. REV proposes that information regarding transmission and distribution constraints should be made available to developers via an online mechanism.[98]

The Department agrees with REV's suggestion that an initial solicitation on June 1, 2013, for projects under Section 8005a(d)(2), may be appropriate as it provides time for the Board to determine the size of any reliability gaps associated with identified constraints, and also time to determine how the Board will measure the value of costs and benefits in a solicitation. However, the Department disagrees with REV's proposal to select projects on a lottery basis. The Department asserts that such an approach would not be practical in evaluating sufficient benefits, and may only be useful in the event of a tie (e.g., multiple projects could provide equal benefits). The Department also disagrees with REV's suggestion that projects may be submitted to the SPEED Facilitator at any time. The Department contends that time-certain solicitations would provide the time necessary for thorough consideration of the value of each project, would ensure that the best available information is used in project evaluations, and would likely reduce the administrative costs and provide greater process certainty to developers.[99]

BED largely agrees with the concepts in the Straw Proposal.[100] BED supports initially limiting implementation of Section 8005a(d)(2) to address bulk transmission and predominantly bulk transmission constraints identified in VELCO's Long Range Transmission Plan ("LRTP"). BED proposes that the best test to determine whether a bulk or predominantly bulk constraint could be defined as a transmission constraint would be to apply the "common component of the [1991 Vermont Transmission Agreement] or under ISO-NE transmission tariffs." BED contends

98. REV Comments of 1/21/13 at 2-3.

99. Department Comments of 1/31/13 at 13.

100. BED/VEC Joint Comments of 1/18/13 at 2.

that constraints that would not fall within this definition would create equity considerations that would need to be addressed – specifically the allocation of standard-offer project costs versus benefits.[101]

IBM does not object to the deletion of Paragraph 3(e)[102] of the Straw Proposal, as suggested by the Department's proposed modifications, provided that certain modifications to paragraph 4 are made. Specifically, IBM's proposed language calls for constraint solutions (or combinations of resources) to be identified on a ratepayer cost-effectiveness basis.[103] IBM does not support modification of the VSPC NTA Screening Tool as proposed by the Department. IBM argues that this will allow implementation of the process with a well-defined scope, and that the Board may utilize its discretion to subsequently refine the process.[104]

Allco supports utilization of a VSPC process, generally, and did not comment on the Straw Proposal.[105]

Vermonters for a Clean Environment ("VCE") recommends that any process actively engage local organizations, including regional planning commissions, residents, and other stakeholders. VCE further encourages incorporation of information gleaned from an ongoing Clean Energy Development Fund ("CEDF") review of the performance of projects that it funded versus its expectations.[106]

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101. BED Comments of 12/28/12 at 1.

102. Paragraph 3(e) of the Straw Proposal requires utilities to perform an analysis that considers a role for non-transmission resources including new SPEED plants, other distributed resources, and demand side management (including energy efficiency and demand response) in the resolution of identified constraints. The analysis must include a societal cost-effectiveness test and a ratepayer impact test, and may include consideration of the relative rate and bill impacts of each alternative, the relative feasibility of each alternative, the ability of each alternative to be implemented in a timely manner, the relative economic benefits to the state, and other relevant costs and benefits particular to the set of alternatives under consideration.

103. IBM Comments of 1/26/13 at 2.

104. IBM Comments of 1/26/13 at 1.

105. Allco Comments of 9/12/12 at 2.

106. VCE Comments of 9/14/12 at 1.

Discussion and Conclusions

We find the Straw Proposal to be a reasonable approach to the implementation of Sections 8005a(d)(2)(A)-(C). Therefore, we adopt the Straw Proposal with a number of non-substantive modifications that we find help to clarify the process, the roles of the various participants, and the timing of certain steps within the process. The screening framework and guidelines that we adopt today, pursuant to Sections 8005a(d)(2)(A) and (B), are included as Attachment II to this Order. In addition, two substantive changes were made to the proposed screening framework. Paragraph 5.a. as proposed by GMP states:

> At the stage before a Request for Proposal ("RFP") is issued, the affected utility(ies) should develop methods for deriving values for the variable in the formula understanding that certain rebuttable presumptions may be prescribed by the Board or adopted as a part of the SPEED program (i.e., Steps 1-4 determine the formula's constraint value).

We have deleted this paragraph, and instead included the necessary steps to develop such values in Paragraphs 3.f.i. and 4. Paragraph 6.e. as proposed by GMP states:

> The affected utility(ies) should be afforded the opportunity to evaluate RFP responses and recommend preferred resources. Where there is more than one affected utility, evaluation should be performed using mechanisms established by the Docket 7081 MOU.

We have revised the first sentence to state:

> The affected utility(ies) should be afforded the opportunity to evaluate RFP responses and provide comment, including identifying proposed plants that would not satisfy the requirements listed in 6.a., above.

This revision is necessary to clarify the scope of comments that the affected utility(ies) may offer at this point in the process – it is critical that the affected utility(ies) review RFP responses to ensure that proposed plants satisfy the equivalency requirements, quantity of power, operating requirements, feeder locations, date of need, and any other special conditions. However, it may be inappropriate for the affected utility(ies) to provide comments beyond this narrow scope, as the evaluation of proposed projects that satisfy the technical requirements should be based on the formulaic analysis of sufficient benefits described below.

Given the complexity inherent in resolving transmission and distribution constraints with cost-effective NTAs generally, and specifically the novel approach mandated under Section

8005a(d)(2), we find it prudent to limit our implementation of the statute in the first year to those bulk transmission and predominantly bulk transmission constraints identified in VELCO's LRTP. Indeed, only one distribution constraint has been identified by stakeholders in this proceeding that may be suitable for resolution by new standard-offer plants, and analysis of that constraint is not complete.[107] We find that delaying consideration of distribution constraints for one year strikes the proper balance between the standard-offer program's goal of timely development and the desire to evaluate distribution constraints pursuant to a screening framework designed for those purposes. The Straw Proposal was developed specifically to address bulk transmission and predominantly bulk transmission constraints, and does not address a specific procedure for identified distribution constraints.

We do not find that the VSPC NTA Screening Tool should be modified specifically and solely for the implementation of Section 8005a(d)(2). We agree with the Department that the $2.5 million screening threshold eliminates certain smaller constraints from consideration, and this does not appear to be consistent with Section 8005a(d)(2), which does not differentiate between large and small constraints. However, we are not persuaded that elimination of this portion of the NTA Screening Tool is appropriate at this time. As a practical matter, only one of the constraints identified in the VELCO LRTP may be screened out by this question.[108] We find that a thorough review of the multiple implications of such a modification would be warranted prior to adopting such a change.

The screening framework and guidelines that we adopt today are consistent with the REV Proposal in that the SPEED Facilitator will administer the program. However, we do not accept REV's proposal that implementation of this Section be open to developers on a rolling basis as we find that the imposition of additional administrative costs on all stakeholders that would result from that process would be unreasonable. We also do not accept REV's proposal that

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107. Working Group A *Utility Gap Analysis and Process Recommendations* at 4.

108. GMP states that for the Hartford/Ascutney constraint, "preliminary results to date suggest that any one of several identified transmission solutions would likely be less costly than the lowest cost NTA and it does not appear likely that the least-cost plan for the area will call for the acquisition of new SPEED plants." GMP Comments of 1/25/13. The Working Group A Analysis indicates that GMP has identified two solutions with estimated costs below $2.5 million. Working Group A *Utility Gap Analysis and Process Recommendations* at 3.

projects be selected on a lottery basis. We find that such a selection process would be inconsistent with the statutory directive to implement the standard-offer program at the lowest feasible cost while ensuring timely development. Selection by lottery would leave to chance whether lowest feasible costs are achieved. Instead, RFP responses pursuant to this section will be evaluated, ranked, and selected in part based on their cost of development, thus adhering to this statutory objective of lowest feasible cost while not hazarding timely development. Finally, with respect to REV's recommendation that information regarding constrained areas be made online via map, we find that this may have long-term merit, however, development of such a tool in the short term is not practical.

Regarding BED's concerns regarding equity of costs and benefits for those projects that would fall outside of its definition of transmission constraint, we find that no relief for BED's concern is available under Section 8005a(k). We do note that as contemplated above, our first-year implementation shall be limited to the consideration of bulk and predominantly bulk transmission constraints, and that the mechanism(s) for addressing constraints beyond this narrow scope, including distribution constraints, will be developed throughout the coming year. Therefore, BED's equity concerns may be directly addressed in subsequent proceedings or by other means.

Regarding IBM's proposal that calls for constraint solutions (or combinations of resources) to be identified on a ratepayer cost-effectiveness basis, we do not adopt this proposed change at this time. Instead, solutions shall be evaluated on the basis of both societal and ratepayer cost-effectiveness.

**(3) Sufficient Benefit Test**

The Department contends that to the extent possible, subjective judgement in the evaluation of proposed standard-offer projects under Section 8005a(d)(2) should be eliminated. Accordingly, on January 11, 2013, the Department filed, for discussion purposes, a formulaic approach to the evaluation of whether proposed projects provide sufficient benefits. The Department recommends that in order to simplify initial implementation of Section 8005a(d)(2), a proposed project must provide sufficient benefits under both a societal and ratepayer benefit-cost test to garner approval. Under the proposed societal test, the sum of a proposed project's offer price and "other actor costs" (e.g., federal tax credits) is compared to societal avoided costs (e.g., energy, capacity, avoided in-state transmission investments, externalities, etc.) multiplied by a "program risk buffer" (an adjustment to avoided costs to account for uncertainty related to the standard-offer program's integration into utility least-cost planning). Under the proposed ratepayer test, the proposed project's offer price is compared to ratepayer avoided costs (e.g., energy, capacity, Regional Network Service Charge ("RNS") costs, in-state transmission investments, RECs, etc.), multiplied by the program risk buffer.

There are several notable differences between the proposed ratepayer and societal benefit-cost tests: (1) Other Actor Costs are not included in the ratepayer test as these costs do not affect the utility; (2) the ratepayer test does not include externalities; (3) values from the avoided RNS charges and greenhouse-gas risks are included in the ratepayer test; and (4) the treatment of specific bulk and predominately bulk transmission infrastructure investment is different between tests (for example, in the societal test, the full value of a transmission investment that is eligible for Pool Transmission Facility treatment to have costs allocated through the RNS is counted, while under the ratepayer test, only the portion of the project that is subject to Vermont ratepayer cost allocation is counted).

Participants' Comments on Sufficient Benefits Test

GMP supports the evaluation of proposed projects using both societal and ratepayer tests.[109] GMP recommends that the Department's proposed benefit-cost analysis structure be adopted, and states that the results of the analysis will only be valid and useful if the crucial inputs to the analysis are carefully considered and properly estimated. GMP notes that the Department has convened a working group to collaboratively determine appropriate values for the variables used in the analysis.[110]

The Department contends that for long-term implementation of the standard-offer

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109. GMP Comments of 1/18/13 at 3.

110. GMP Comments of 1/31/13 at 2.

program, the societal test should be the primary test to evaluate proposals in order to determine whether they provide sufficient benefits. The Department recommends that a ratepayer test should also be reviewed and considered. The Department states that Paragraph 40 of the Docket No. 7081 MOU requires an "evaluation of each alternative under the societal test," and obligates utilities to address specific variables that impact a utility's cost of service. The Department observes that the societal benefit-cost test has long been a part of energy efficiency portfolio evaluation.[111]

IBM recommends that projects seeking a standard-offer contract under Section 8005a(d)(2) should be evaluated under a ratepayer test, and not a societal test. IBM asserts that the Legislature created the standard-offer program as a means to promote the development of small-scale renewable energy projects that have societal benefits, yet it imposed a cap to limit ratepayer impacts. IBM argues that the addition of Section 8005a(d)(2) recognizes that the cap should not apply when small-scale renewable energy projects do not have ratepayer impacts. IBM asserts that evaluating potential projects pursuant to a ratepayer test would be consistent with utility least-cost planning principles.[112] IBM also contends that Section 8005a(d)(2) does not indicate a deadline for issuing an RFP for projects under this subsection, therefore, if additional time is required to determine the method for evaluating sufficient benefit then additional time should be taken.[113] IBM supports further evaluation by the working group established for this purpose.

REV supports use of a societal test. REV contends that a ratepayer impact test has little relevance to the determination of sufficient benefit, and instead states that consideration of a Vermont "ratepayer societal test" may be appropriate as a secondary screen to focus specifically on the benefits that accrue solely to the operation of Vermont's grid.[114]

111. Department Comments of 1/31/13 at 9-10.

112. IBM Comments of 1/26/13 at 2.

113. IBM Comments of 1/31/13 at 2.

114. REV Comments of 1/31/13 at 2.

Discussion and Conclusions

We agree with the Department that in our evaluation of whether proposed standard-offer projects would provide sufficient benefits to the operation and management of the grid, such that their capacity would be exempted pursuant to Section 8005a(d), subjectivity should be removed to the extent practicable. Accordingly, applying a formulaic approach to the question that would incorporate predetermined, transparent, and collaboratively developed terms and values appears to be a reasonable approach. As noted above, a working group has formed to evaluate the appropriate terms and values that may be included in a sufficient benefit test formula. This working group is expected to provide a recommendation (or recommendations, if consensus is not achieved among its members) in late February 2013, with comments on the recommendation(s) due in early March 2013. Therefore, we adopt IBM's recommendation that we not establish a sufficient benefit test in today's Order. Instead, we will review the recommendation(s) of the working group and any comments thereon, and direct Board staff to conduct further proceedings as necessary to resolve this matter while being mindful of the goal of achieving "timely development at the lowest feasible cost."[115]

With respect to the question of whether to incorporate a societal benefit-cost test, a ratepayer benefit-cost test, or both, while we do not make a determination today (though both terms remain a part of the screening framework), it bears noting that the guidelines adopted in both Docket Nos. 7081 and 6290 call for the evaluation of alternatives pursuant to a societal test. However, the standards of review adopted in those dockets allow for the additional consideration of other appropriate factors, including but not limited to resource availability, financial constraints, and financial effects on the utility and its customers.[116]

### (4) Evaluation of Identified Constraints

As noted above, Working Group A was given the following tasks: (1) identifying areas of transmission, sub-transmission, and distribution systems that have reliability constraints that

115. *See* Section 8005a(f).

116. Docket No. 7081, Order of 6/20/07 at 21; Docket No. 6290, Order of 1/15/03 at 7-8 and 9.

could be affected by additional load, and the forecasted need dates; (2) identifying the "wires" solution and providing an estimated cost of that solution; (3) describing the performance characteristics that any solution must meet in order to satisfy the appropriate reliability criteria (e.g., the equivalence); (4) identifying the geographic areas where generation or load reduction could defer or avoid the wires solution and estimating the quantity of generation or load reduction necessary to effectively address the reliability constraint; and (5) quantifying the amount of energy efficiency potential in the targeted area that is not already incorporated in the controlling forecast. On January 11, 2013, Working Group A submitted, on behalf of BED, GMP, VELCO, VEC, VPPSA, and Washington Electric Cooperative, Inc. ("WEC", collectively, the "submitting parties"), its analysis titled *Utility Gap Analysis and Process Recommendations* (the "Analysis"). Working Group A subsequently provided a correction and updated analysis on January 18, and January 24, 2013, respectively.

The Analysis recommends that the relevant constraints for which standard-offer projects may qualify under Section 8005a(d)(2) are those that have been "screened in" using the NTA Screening Tool, in other words, those constraints that have some reasonable likelihood of being cost-effectively addressed by NTAs as defined by the screening tool's criteria. Pursuant to ¶ 21 of the Docket No. 7081 MOU, the VSPC must adopt a screening tool "to screen from further analysis only those projects that have no reasonable likelihood of being cost-effectively addressed by NTAs." An identified constraint that screens in is then subjected to a full NTA analysis to determine whether a specific configuration of NTA solutions, or a hybrid of transmission and NTAs, can resolve the constraint cost-effectively.[117]

The submitting parties recommend, for identified constraints where NTA analysis is not yet complete, that consideration of standard-offer plants that may provide sufficient benefit be deferred in the current year's cycle. The submitting parties assert that the provisions of Docket No. 7081 ensure that identified constraints receive continuing attention and that affected utilities are required to update the VSPC quarterly, and the Board and Department annually, on implementation of project-specific action plans.

117. Analysis at 2.

The Analysis indicates that three system constraints or reliability deficiencies were identified in VELCO's 2012 LRTP: (1) Central Vermont; (2) Rutland Area; and (3) Hartford/Ascutney. The Central Vermont deficiency is a bulk system issue for which all Vermont distribution utilities are affected utilities. A study group (the "NTA Study Group") comprised of the distribution utilities and VELCO, and led by GMP, has been conducting a full NTA analysis, which in conjunction with the ISO-New England Vermont/New Hampshire Needs Assessment, served to inform the Analysis. The Rutland Area deficiency is a predominantly bulk system deficiency for which GMP is the affected utility. While GMP has developed and presented certain information regarding the deficiency, it has not yet completed its analysis. Accordingly, the submitting parties recommend that the Rutland Area be considered for its potential to be mitigated by standard-offer projects in the 2014 cycle. The Hartford/Ascutney constraint is a predominantly bulk system deficiency for which GMP is the affected utility. The VELCO 2012 LRTP identifies this deficiency as screened in for full NTA analysis; however, GMP has since identified two viable sub-transmission solutions with estimated costs below $2.5 million. Because the NTA Screening Tool screens out of full NTA analysis projects for which the likely reduction in costs from the potential elimination or deferral of the upgrade is less than $2.5 million, the submitting parties recommend that the Hartford/Ascutney deficiency be eliminated as a candidate to be addressed by standard-offer projects in the 2013 cycle.[118] In addition to these constraints, Working Group A also informally reviewed one identified distribution constraint – the St. Albans area within GMP's service territory.

The Central Vermont constraint consists of two transmission elements: the 18.2-mile K-32 line from Coolidge to Cold River and the 5.6-mile K-35 line from Cold River to North Rutland. The Analysis indicates that the most recent VELCO forecast, updated in October 2012, indicates that the critical load level for the K-32 line has already been reached, and the critical load level for the K-35 line will be reached in 2017. The submitting parties state that resources already being implemented under existing state programs may meet all of the reliability needs of the K-35 line, thus the reliability need may be postponed beyond ten years from now. The submitting parties further state that the existence of a reliability gap for the K-32 line is an open

118. Analysis at 3.

question that may be informed by a forthcoming updated VT/NH Needs Assessment study. The NTA Study Group has concluded that given this uncertainty and the pending VT/NH Needs Assessment study, expected in 2013, it is premature to quantify the size of any reliability gap. The submitting parties therefore contend that the most appropriate response is to manage the Central Vermont reliability deficiency through operational means, and that implementation of long-term transmission or NTA solutions is not necessary nor in the best interest of ratepayers.[119]

The St. Albans area of GMP's service territory faces a future summer reliability constraint from the loss of one of the area's 34.5/12.47 kV substations in the event of either a planned or unplanned transformer outage. New load demand and any ancillary growth will likely require the construction of a new 34.5/12.47 kV substation at the cost of approximately $1.5 million. Because of this reliability constraint, the St. Albans area was approved by the Board for the delivery of targeted incremental energy efficiency investments through 2014.[120] Total estimated energy efficiency savings are expected to be 1.8 MW, representing all available cost-effective energy efficiency potential. GMP is investigating other resources to address forecasted load growth and to reduce uncertainty in forecasted load. GMP has not yet completed its efforts to study alternatives or to develop a final plan that identifies the least-cost strategy to address this area. Accordingly, GMP does not know whether distributed generation would be required to address the constraint in a cost-effective manner.[121]

<u>Participants' Comments on *Utility Gap Analysis and Process Recommendations*</u>

GMP supports the recommendations made by Working Group A that the Hartford/Ascutney and Rutland Area constraints be eliminated as candidates to be addressed in the current cycle. GMP asserts that NTA analysis for these constraints is expected to be presented to the VSPC by November 2013. Accordingly, GMP recommends that it submit

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119. Analysis at 4-5.

120. EEU-2010-06, Order of 2/16/12.

121. Analysis at 12.

information concerning these constraints in time for the 2014 standard-offer cycle.[122]

The Department supports the Analysis with regard to the Central Vermont constraint, and recommends that at this time it is not appropriate to solicit standard-offer projects to address this constraint. The Department recommends that initial implementation of Section 8005a(d)(2) requires flexibility, and thus a mid-year solicitation resulting from recently completed reliability gap analyses under certain circumstances would be appropriate. Concerning the ongoing analysis of the Hartford/Ascutney and Rutland Area constraints, the Department asserts that it is unlikely that the analysis will be fully vetted before April 1, 2014. Therefore, the Department concurs that addressing these particular constraints in 2014 is appropriate.[123]

BED agrees that soliciting offers to address the Central Vermont constraint is not appropriate at this time.[124]

IBM contends that, for identified constraints where analysis is not complete, deferring those areas from the current year's cycle and performing an annual solicitation make the process more streamlined and predictable.[125]

REV asserts that the Rutland Area and St. Albans constraints should be addressed by standard-offer projects, and does not believe that "deferral of consideration of these constraints meets the intent of the legislation."[126]

Discussion and Conclusion

The Working Group A Analysis of identified constraints, which incorporates ongoing work by the NTA Study Group, recommends that none of the constraints identified in the VELCO LRTP be considered candidates for potential mitigation by standard-offer projects pursuant to Section 8005a(d)(2) during the first-year of implementation. For the Central

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122. GMP Comments of 1/25/13 at 3.

123. Department Comments of 1/31/13 at 17.

124. BED Comments of 1/31/13 at 4.

125. IBM Comments of 1/26/13 at 1.

126. REV Comments of 1/31/13 at 3.

Vermont constraint, the Analysis concludes that short-term operating solutions are more appropriate than long-term transmission or non-transmission solutions. For the Rutland Area and Hartford/Ascutney constraints, the Analysis suggests that ongoing NTA analysis will be completed in the coming year, that such analysis will be presented to the VSPC in November, and that the areas would be more appropriately considered in future cycles. Similarly, the St. Albans constraint is the subject of ongoing analysis.

In this Order we do not specifically approve or reject the Working Group A Analysis. It would be premature for the Board to determine in this Order whether any of the areas discussed in the Analysis should be addressed by new standard-offer projects prior to the formal implementation of the screening framework and guidelines that we adopt today that have been designed for this purpose. Instead, we direct the affected utility(ies) to follow the requirements of the screening framework and guidelines. At the time that the screening framework and guidelines identify an opportunity to address transmission or distribution constraints via standard-offer projects, we will develop and issue an RFP that will provide potential developers with sufficient information, pursuant to Section 8005a(d)(2).

We do not adopt REV's recommendation that the identified areas of constraint be immediately addressed by standard-offer projects pursuant to Section 8005a(d)(2). In order for the Board to answer the question of whether proposed standard-offer projects would provide sufficient benefit to the operation and management of the grid, or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit, it is imperative that analysis regarding the existence, nature and magnitude of any constraint be complete, as well as analysis of all potential cost-effective solutions.

## V. Greenhouse Gas Reduction Credit Program

Section 8006a requires the Board to develop a GHG Reduction Credit mechanism for certain customer(s). In particular, pursuant to Section 8006a(a), greenhouse gas reduction credits generated by an eligible ratepayer shall result in an adjustment of the standard-offer programmatic cap established under Section 8005a(c)(1).

Pursuant to Section 8006a(c)(1)(C), the Board is required to adjust the annual increase to the programmatic cap "to account for GHG reduction credits by multiplying the annual increase by one minus the ratio of the prior year's GHG reduction credits to that year's statewide retail electric sales." The amount of the prior year's GHG reduction credits is determined in accordance with the requirements of Section 8006a(a). In addition, during years in which the annual increase in the programmatic cap is 10 MW, the adjustment in the annual increase is applied proportionally to the independent developer block and the provider block.

In a January 29, 2013, Order, the Board determined that IBM satisfies the ratepayer eligibility requirements defined in Section 8006a(b)(1), and approved IBM's independent third-party verifier of GHG reductions.

Section 8006a(c) requires that greenhouse gas reduction credits be calculated as follows:

> (1) Eligible reductions shall be quantified in metric tons of $CO_2$ equivalent, in accordance with the methodologies specified under 40 C.F.R. part 98, and may be counted annually for the life of the specific project that resulted in the reduction.
>
> (2) Metric tons of $CO_2$ equivalent quantified under subdivision (1) of this subsection shall be converted into units of energy through calculation of the equivalent number of kWh of generation by renewable energy plants, other than biomass, that would be required to achieve the same level of greenhouse gas emission reduction through the displacement of market power purchases. For the purpose of this subdivision, the value of the avoided greenhouse gas emissions shall be based on the aggregate greenhouse gas emission characteristics of system power in the regional transmission area overseen by the Independent System Operator of New England (ISO-NE).

Section 8006a(d) requires that an eligible ratepayer report to the Board annually on each specific project undertaken to create eligible reductions. Section 8006a(e) requires that a distribution utility provider pass on savings that it realizes through greenhouse gas reduction credits proportionally to the eligible ratepayers generating the credits.

The development of a GHG Reduction Credit mechanism pursuant to Sections 8005a(c)(1)(C) and 8006a is addressed below.

<u>Participants' Recommendations</u>

IBM, in consultation with the Department, GMP, and VEPP Inc., made the following recommendations for the development of a GHG Reduction Credit mechanism.[127]

In order to determine the annual adjustment to the programmatic cap, the GHG reductions achieved each year by the eligible ratepayer (metric tons per year) must be expressed in terms of energy (kWh per year). IBM recommends, pursuant to Section 8006a(c)(2), that the most current system emission rate of $CO_2$, reported annually by ISO-NE, be used to convert metric tons of $CO_2$ equivalent per year to a corresponding amount of kWh per year. ISO-NE annually publishes the Electric Generator Air Emissions Report, which includes the annual average system emission rate referenced in Section 8006a(c)(2).[128] In the interest of process efficiency, IBM recommends that the Board require an eligible ratepayer to perform this conversion to kWh as part of its annual report to the Board.

Section 8006a(a) caps the amount of a year's GHG reduction credits (in kWh) at the kWh of retail electric sales to eligible ratepayers creating credits. Thus, an eligible ratepayer's annual report to the Board needs to include its electric usage in kWh for the year, and an explicit determination of the effective amount of its GHG reduction credits in kWh. IBM recommends that the annual report filed by the eligible ratepayer to the Board include the following: (1) a summary of eligible GHG reductions by project, in metric tons $CO_2$ equivalent; (2) independent third-party verification of eligible GHG reductions, in metric tons $CO_2$ equivalent; (3) conversion of metric tons $CO_2$ equivalent to corresponding kWh; (4) the eligible ratepayer's serving utility; (5) the eligible ratepayer's billed electric usage for the year, in kWh; and (6) the eligible ratepayer's GHG reduction credits, in kWh (lesser of (3) or (5)).

Pursuant to Section 8005a(c)(1)(C), the Board is required to adjust the annual increase in standard-offer capacity to account for GHG reduction credits by April 1. The following information is needed to make that adjustment: (1) the eligible ratepayer's prior year GHG reduction credits in kWh, from the annual report; and (2) the prior year's statewide retail electric sales, in kWh. The Department compiles data on statewide electric sales, and historically, the

127. IBM Comments of 9/20/12 at 3-4.

128. The 2011 system emission rate for $CO_2$ is 780 lb/MWH as reported in *2011 ISO New England Electric Generator Air Emissions Report*, February 2013. The report is available at: http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf.

target date for obtaining these data from utilities has been April 15. IBM represents that the Department will strive to collect preliminary annual sales figures from each utility by the end of February each year to enable completion of this adjustment by April 1.

IBM agrees that there may be a *de minimis* level of total GHG reduction credits below which an adjustment to the annual increase is not meaningful. IBM is not opposed to setting a threshold for reductions to the annual cap increase of 10 kW (or 0.01 MW).

In allocating the purchased standard-offer power to Vermont utilities, the SPEED Facilitator is required to adjust the *pro rata* share calculations to account for any GHG reduction credits. In addition, the utility (GMP) of the eligible ratepayer (IBM) is required to make a billing adjustment to reflect the annual GHG reduction credits. A working group, comprised of IBM, the SPEED Facilitator, the Department, and GMP, was established to address these issues. The working group requests additional time to file a recommendation with the Board.

<u>2013 Annual Report</u>

On February 20, 2013, IBM filed a 2013 annual report on its GHG reduction program. IBM stated that its 2012 GHG reduction credits are equal to 39,089,034 kWh.

<u>Discussion and Conclusions</u>

Pursuant to Sections 8005a(c)(1)(C) and 8006a, the Board is required to develop a GHG Reduction Credit mechanism that includes: (1) a methodology to adjust the annual increase in standard-offer capacity to account for GHG reduction credits; (2) annual milestones and filing requirements for the reporting of GHG reduction credits; and (3) a methodology to allocate the *pro rata* share of standard-offer power to Vermont utilities to account for any GHG reduction credits.

We accept the participants' recommendations for the methodology to adjust the annual increase in standard-offer capacity to account for GHG reduction credits. In order to determine the annual adjustment to the programmatic cap, the GHG reductions achieved each year by the eligible ratepayer (metric tons of $CO_2$ equivalent per year) will be expressed in terms of energy (kWh per year) using the most current system emission rate of $CO_2$, reported annually by ISO-

NE. The Board requires that an eligible ratepayer perform this conversion to kWh as part of its annual report to the Board.

Pursuant to Section 8005a(c)(1)(C), the Board is required to adjust the annual increase in standard-offer capacity to account for GHG reduction credits by April 1. The adjustment is made by multiplying the annual increase by one minus the ratio of the prior year's GHG reduction credits to that year's statewide retail electric sales. The Department compiles data on statewide electric sales, and historically, the target date for obtaining these data from utilities has been April 15. Given the April 1 deadline, the most recently available data on statewide retail electric sales will be used. Thus, for the 2013 cap adjustment, 2011 statewide retail electric sales will be used, since they represent the most recently available data. The use of 2011 electric sales data is consistent with the most current system emission rate of $CO_2$, reported annually by ISO-NE, which has a similar lag in reporting.

We accept the participants' recommendation that the annual report contain the following: (1) a summary of eligible GHG reductions by project, in metric tons $CO_2$ equivalent; (2) independent third party verification of eligible GHG reductions, in metric tons $CO_2$ equivalent; (3) conversion of metric tons $CO_2$ equivalent to corresponding kWh; (4) the eligible ratepayer's serving utility; (5) the eligible ratepayer's billed electric usage for the year, in kWh; and (6) the eligible ratepayer's GHG reduction credits, in kWh (lesser of (3) or (5)). In order to complete the annual cap adjustment by April 1 of each year, the annual report is required to be filed by February 20. Interested parties will have 10 days to file comments on the annual reports.

Participants recognize that there is a de minimis level of total GHG reduction credits below which an adjustment to the annual programmatic cap is not meaningful. We establish a threshold for reductions to the annual programmatic cap of 10 kW (or 0.01 MW).

A working group, comprised of IBM, the SPEED Facilitator, the Department, and GMP, was established to address: (1) the development of a methodology to allocate the *pro rata* share of standard-offer power to Vermont utilities to account for any GHG reduction credits; and (2) the billing adjustment made by the utility of the eligible ratepayer to reflect the annual GHG reduction credits. The working group requests additional time to file a recommendation with the Board. We require that the participants file a proposal by June 1, 2013.

IBM filed a 2013 Annual Report on its GHG reductions. Using 2011 statewide retail electric sales, the reported GHG reductions would reduce the annual program capacity by 35 kW. Any comments on the 2013 Annual Report must be filed with the Board no later than March 8, 2013.

## VI. Conclusion

As we noted in our September 30, 2009, Order establishing the standard-offer program, the standard-offer program involves a complex undertaking among developers, utilities, the SPEED Facilitator, and the regional grid operator. The changes mandated by Act 170 also involve a complex undertaking. We expect that the determinations reached today may need to be modified, on a going-forward basis, as we gain more experience with the standard-offer program and as we gather additional information on these issues.

We intend to proceed expeditiously with the subsequent procedures described in this Order, and to take all other steps necessary and appropriate to ensure that the standard-offer program operates effectively, efficiently, and in accordance with the directives of Act 170.

## VII. Order

It Is Hereby Ordered, Adjudged and Decreed by the Public Service Board ("Board") of the State of Vermont that:

1. Effective for any standard-offer contract, executed after March 1, 2013, the standard-offer prices for renewable power under 30 V.S.A. § 8005a(b)(2) shall be determined through a request for proposal issued by the SPEED Facilitator and shall be no higher than the avoided costs as specified within this Order. For farm methane projects the standard-offer price shall be the avoided costs as specified within this Order.

2. By April 1 of each year, the SPEED Facilitator shall issue a request for proposals, consistent with the requirements as set forth in Attachment I to this Order, to solicit standard-offer projects to meet the requirements of 30 V.S.A. § 8005a(c).

3. Upon completion of the request for proposal selection process, and five days prior to the announcement of the award group, the SPEED Facilitator shall provide to the Board the

results of the award group under the request for proposal, with the recommendation that the Board authorize the SPEED Facilitator to enter into contracts with such facilities.

4. The current waiting list for the standard-offer program will cease on March 1, 2013. If capacity becomes available between March 1 and April 1, 2013, then the SPEED Facilitator shall include that capacity in the April 1, 2013, request for proposal solicitation.

5. For Vermont distribution utilities, all capital costs and operating expenses associated with a standard-offer project shall be booked "below the line" and shall not be added to rate base or recovered in retail rates as an expense.

6. We adopt a Screening Framework and Guidelines, specified in Attachment II to this Order, that will provide potential standard-offer plant developers with adequate information regarding constrained areas of the electric grid in which generation having particular characteristics is reasonably likely to provide sufficient benefit to the operation and management of the grid.

7. Pursuant to 30 V.S.A. § 8005a(d)(2), only those standard-offer plants that mitigate a transmission or distribution constraint identified by the Screening Framework and Guidelines shall be deemed to provide sufficient benefit to the operation and management of the electric grid or a provider's portion thereof.

8. We remand Docket No. 7873 to Board staff in order to conduct such additional proceedings as are necessary to: (1) develop a sufficient benefit test to be used in the Board's evaluation of projects that seek to participate in the standard-offer program pursuant to 30 V.S.A. § 8005a(d)(2); (2) develop a model Request for Proposals for such projects; (3) expand for future years the scope of eligible grid constraints to include distribution; (4) develop revised avoided cost-figures applicable to the Provider Block; and (5) investigate establishing technology allocations, based on the cumulative 127.5 MW capacity of the standard-offer program, immediately following the 2013 RFP process.

9. By February 20 of each year, any ratepayer eligible for the Greenhouse Gas Reduction Credit Program, pursuant to 30 V.S.A. § 8006a, shall file with the Board an annual report containing: (1) a summary of eligible greenhouse gas reductions by project, in metric tons $CO_2$ equivalent; (2) an independent third party verification of eligible greenhouse gas reductions, in

metric tons $CO_2$ equivalent; (3) the conversion of metric tons $CO_2$ equivalent to corresponding kWh; (4) the eligible ratepayer's serving utility; (5) the eligible ratepayer's billed electric usage for the year, in kWh; and (6) the eligible ratepayer's greenhouse gas reduction credits, in kWh (lesser of (3) or (5)). Any comments on the annual report each year must be filed with the Board no later than 10 days after the date that the annual report is filed. Any comments on the 2013 annual report must be filed with the Board no later than March 8, 2013.

10. By June 1, 2013, IBM, working with interested parties, shall file a recommendation with the Board regarding: (1) the development of a methodology to allocate the *pro rata* share of standard-offer power to Vermont utilities to account for any greenhouse gas reduction credits; and (2) the billing adjustment made by the utility of the eligible ratepayer to reflect the annual greenhouse gas reduction credits.

Dated at Montpelier, Vermont, this 1st day of March, 2013.

| | | |
|---|---|---|
| s/ James Volz | ) | PUBLIC SERVICE |
| s/ David C. Coen | ) | BOARD |
| s/ John D. Burke | ) | OF VERMONT |

OFFICE OF THE CLERK

FILED: March 1, 2013

ATTEST: s/ Susan M. Hudson
Clerk of the Board

*NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: psb.clerk@state.vt.us)*

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