2018 Annual Report on the Renewable Energy Standard

Vermont Department of Public Service

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Submitted to the House Committee on Commerce and Economic Development, the Senate Committees on Economic Development, Housing and General Affairs and on Finance, and the House and Senate Committees on Natural Resources and Energy

Introduction

Pursuant to 30 V.S.A. § 8005b, the Department of Public Service (PSD or Department) provides this annual assessment of the ongoing impacts of the Renewable Energy Standard (RES).

This report is structured around two main sections, each corresponding to the two main reporting requirements laid out in subsection (b) of Section 8005b.[1] The first main section is retrospective in nature; it looks backward to evaluate the historical performance of the RES program and to take stock of the costs and benefits so far attributable to the RES (see *Summary of Program Performance to Date*). The other main section is prospective in nature; it summarizes the results of modeling exercises undertaken by PSD in order to project how the RES is likely to affect Vermont, given past performance and current trends (see *Expectations of Future Program Performance*).

For this first submission to the legislature, PSD's retrospective evaluation is necessarily abbreviated; utility RES compliance filings for 2017 will not be filed until summer of 2018 and the Public Utility Commission (PUC) will not rule on these filings until December 15, 2018. Future versions of this report will have more history to draw from and a fuller basis for any program modification recommendations. The bulk of this year's report is contained in the prospective section, which summarizes the results of a scenario analysis of RES impacts over the next ten years. Going forward, PSD will be able to draw on measurements of actual RES performance to inform its prospective analyses.

In addition to the two main sections cited above, this report includes a methodology (*Methodology and RES Model Overview*) and two appendices. The methodology section gives a cursory description of the mechanics of the scenario analysis model that PSD used to support the quantitative projections presented in the prospective section (*Expectations of Future Performance*). Appendix I contains the statutory language describing the purpose and requirements of this report. Appendix II lists the values assigned to the key modeling variables that drive different results in PSD's scenario analysis model.

Summary of Findings

- Utility compliance with the RES will mean significant ongoing reductions in fossil fuel consumption by Vermonters, primarily through the greening of their electricity supply. By 2027, PSD estimates that fossil fuel consumption will be lower by more than 10,000,000 MMBtu, and carbon dioxide emissions will be lower by 600,000 to 700,000 tons because of the RES; reductions on the order of 10% relative to current levels.
- PSD expects utilities to meet all 2017 RES requirements without difficulty. However the Department will have to await a formal compliance review to know the exact costs utilities incurred in the process. Looking forward, PSD estimates the utilities' cost of continuing to meet RES obligations is likely to fall within a range between $94,000,000 and $134,000,000, cumulatively, over the next ten years (expressed in 2018 dollars). Though less likely from today's perspective, it is conceivable that RES compliance costs could amount to as much as $200,000,000 over the next ten years.
- The main driver of utility compliance expenditures will be the cost to acquire distributed generation (DG) resources that produce Tier 2 eligible renewable energy certificates (RECs). PSD estimates that these costs are likely to range from $80,000,000 to $96,000,000 (in 2018 dollars), over the next ten years, depending on the extent to which DG costs continue to decline. Utilities are also likely to incur several million dollars of costs incentivizing customers to adopt Tier 3 eligible fossil fuel reduction measures, as much as $23,000,000

[1] Appendix I of this document contains the relevant language of Section 8005b.

(in 2018 dollars), over the next ten years if fossil fuel prices fall or remain at today's relatively low levels. In addition, Tier 3 fossil fuel reduction measures that consume electricity, like cold climate heat pumps (CCHPs) and electric vehicles (EVs), could prove costly for utilities to serve if those technologies are not deployed with controls that enable customers to avoid adding to peak demand.

- There will likely be upward electricity rate pressures associated with these levels of compliance expenditure. PSD estimates that retail rates will most likely average between 0.60% and 1.15% higher over the next ten years because of the RES, but possibly as much as 2.0% higher if compliance costs turn out significantly greater than the range PSD currently considers probable. Controlling the time of use for new Tier 3 loads to avoid adding to peaks will help keep the rate impact on the lower side of this range , regardless of how high or low compliance costs turn out to be.

Overview of RES and Reporting Requirement

Act 56 of 2015 established a Renewable Energy Standard (RES) for Vermont electric distribution utilities (utilities or DUs), requiring them to increase the portion of renewable energy they sell to Vermont customers to 55% in 2017, rising over time to 75% in 2032. This is the RES Tier 1 requirement. Tier 2 of the RES requires that, of this total quantity of renewable energy, starting in 2017, the equivalent of 1% of sales will come from small generators (less than 5 MW) connected to Vermont's distribution grid (or otherwise serving to avoid costly transmission upgrades), climbing to 10% of sales in 2032. The Tier 2 requirement is a subset, or "carve-out," of the Tier 1 requirement.

The RES requires utilities to hold renewable energy certificates (RECs) to satisfy their Tier 1 and Tier 2 obligations, consistent with the renewable portfolio standards (RPS) in effect in all five other New England states. RECs, which are each equivalent to 1 MWh generated from a renewable resource, are created when a renewable unit generates electricity. RECs can be sold separately (or "unbundled") from the electricity generated by the unit. For example, a solar facility could sell electricity to one DU and RECs to another DU, or to a separate private party. RECs are registered by generators in the NEPOOL Generator Information System (NEPOOL GIS). The NEPOOL GIS tracks the characteristics of each generator in order to determine which "classes" of RECs produced by a given generator are eligible for which states' renewable portfolio standards.

Act 56 also created a separate Tier 3 "energy transformation" obligation that rises from 2% of sales in 2017 to 12% in 2032 (with the exception that small municipal utilities will not have an obligation until 2019). A utility has the option of meeting this requirement with additional distributed renewable generation (Tier 2 resources), or through projects that result in net reductions of fossil fuel consumption by the utility's customers. Examples of these energy transformation projects could include weatherizing a building; installing air source or geothermal heat pumps, biomass heating systems and other high-efficiency heating systems; industrial process fuel efficiency improvements; increased use of biofuels; deployment of electric vehicles or related charging infrastructure; and construction of infrastructure that supports storage of renewable energy. The Tier 3 requirements are additional to the Tier 1 requirements.

Methodology and RES Model Overview

To assist in its projections of future RES impacts, the Department developed a spreadsheet-based scenario analysis tool (the Consolidated RES model or RES model) capable of accommodating a range of assumptions regarding fossil fuel energy price levels, the cost and technological performance of Tier 3 measures, and the cost to utilities of acquiring new sources of renewable generation and supplying new electrical loads.[2] It is important to stress that the RES Model is explicitly not a forecasting tool. It is designed to help answer questions about worst, best and likely case scenarios, not to predict a precise outcome. This methodology section provides a high level explanation of the key linkages in the RES model that determine the different assumption-dependent results reported below in the prospective section of this document (see *Expectations of Future Program Performance*). Appendix II to this report provides additional documentation of the key variables used by the RES model and the values assigned to them in PSD's scenario analyses.

The main output of the RES model, for any given set of assumptions, is a calculation of the total incremental utility expenditure required to comply with the RES requirements over the next ten years. Conceptually, this compliance expenditure can be mapped to each of the three tiers of the RES. The cost to comply with the

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[2] The RES Model is available on the Department's website at: http://publicservice.vermont.gov/publications-resources/publications

requirements of Tier 1 and Tier 2 are determined primarily by the amount that utilities are assumed to pay in order to acquire RECs from eligible renewable generation resources. The cost to comply with the requirements of Tier 3 consists of three distinct components: 1) the incentives paid by utilities to encourage customer adoption of fossil fuel reduction measures, 2) program administration overhead, and 3) the cost to serve any new electric load associated with customer adoption of fossil fuel reduction measures.

Tier 1 and Tier 2 Compliance Costs

Utilities must acquire and retire RECs to meet their Tier 1 and Tier 2 obligations. The RES Model allows for different assumptions about the prices utilities will pay to acquire the RECs they must retire. In general, there are three possible sources of RECs available to utilities, each with different cost implications: 1) their own generation resources, 2) “bundled” contracts with other generators, and, 3) REC traders.

Utilities that own renewable plants are entitled to the RECs created alongside the physical power their generation resources produce. Utilities can also purchase RECs from third parties, either through bilateral contracts with other owners of generation, or from intermediaries that specialize in trading RECs. RECs purchased though bilateral contracts with generation owners are typically, though not always, “bundled” into a broader Power Purchase Agreement (PPA) that includes the sale of energy and capacity. PPAs structured like this do not typically assign a specific price to the REC component of the contract. The RECs that utilities can purchase from REC traders, on the other hand, are “unbundled” from the physical power underlying their origination and are offered at explicit prices quoted by broker-dealer organizations. REC markets provide utilities and other REC buyers the option of obtaining RECs without having to take on the full cost of purchasing or generating physical power. They also provide a benchmark for valuing RECs that are included in bundled bilateral contracts.

However REC markets do not exist for every type of REC circulating in New England and liquidity in markets that do exist can vary significantly by class of REC. Tier 2 of the RES defines eligible resources as constructed after July 1, 2015 and also located in Vermont. This narrow criteria limits the potential supply of eligible RECs to levels that are probably too low to create the kind of trading opportunities needed for a functioning REC market. It is unlikely, though not impossible, that there will be so much merchant DG built in Vermont over the next 10 years that a surplus of Tier 2 RECs will become available for sale to utilities as unbundled products. As of today, PSD does not expect utilities will have the option to buy unbundled Tier 2 RECs from merchant plants or REC traders. Instead, they will have to obtain Tier 2 RECs through acquisition of physical power, either with bilateral contracts or by commissioning new facilities. This means that in order to meet their Tier 2 obligations, utilities will have to pay the full cost of building, operating and maintaining a renewable DG plant—what is known as the levelized cost of energy (LCOE).

However this assumption is not built into the structure of the RES model and if it so happens that a surplus of Tier 2 RECs does emerge in the years to come, future analyses by PSD may assume that utilities will go on to meet some of their remaining Tier 2 obligation by purchasing unbundled RECs, at prices lower than the full LCOE. For Tier 1, PSD expects utilities will be able to meet the majority of their obligations over the next 10 years with the RECs produced by their owned resources and the RECs they are entitled to by long-term contracts in their portfolios. Because there is likely to be a significant amount of large renewable generation brought on line in New England over the next 10 years, there is likely to be an abundance of unbundled Tier 1 eligible RECs circulating in New England. PSD expects utilities will be able to purchase these surplus RECs from REC traders to make up any difference between their committed supply of Tier 1 RECs and their annual obligation amounts. The RES Model scenarios analyzed by PSD for this report assume utilities will pay an average of around $1.00 per

MWh for Tier 1 RECs (in today's dollars) acquired from all sources (generation, contracts, and wholesale market purchases). If it turns out that the supply of RECs from large generators is tighter than PSD currently expects, future PSD analyses may assume that utilities will have to either pay higher prices to acquire Tier 1 RECs or, if it appears there will be insufficient regional supply for utilities to meet their Tier 1 obligations, build their own generation or enter into PPAs.

In the RES model, total compliance costs for Tiers 1 and 2 are calculated as the product of the assumed cost to acquire RECS ($ per MWh) and the total utility obligation quantity (MWh). The utility obligation quantity is determined by applying the applicable statutory percentage to the annual load forecast volume in a given scenario.[3] If the load forecast in a given scenario is higher, the utility obligation quantity, and therefore Tier 1 and Tier 2 compliance costs, will also be higher. The factors that determine load levels in a scenario (relative to the baseline forecast) are the assumptions made regarding: 1) growth in Net Metering (NM) participation, and 2) the extent to which utilities comply with Tier 3 obligations with measures that build electric load.

Effect of Net Metering on Tier 1 and Tier 2 Obligations

Customer generation reduces the volume of electricity that utilities would otherwise sell to ratepayers. The RES Model allows for different assumptions about the growth of net metered customer production volumes. Assuming larger volumes of future net metered production lowers the forecasted load and thereby reduces the amount of RECs that utilities must retire to meet Tier 1 and Tier 2 obligations. In addition, as outlined in PUC rule 5.100, net metered customers receive $0.06 per kWh ($60 per MWh) more for their generation if they transfer their RECs to the host utility, compared to if the customer decides to retain the RECs. Given the favorable customer economics of selling RECs to utilities, PSD expects the majority of future net metered customers will choose to transfer their RECs. Utilities that acquire RECs from net metering customers must count them towards their Tier 2 obligations. The more net metering customers that sell their RECs to utilities, the less that utilities will have to turn to other sources to acquire RECs. In the scenarios analyzed by PSD for this report, it was assumed that utilities must pay the full LCOE to acquire Tier 2 RECs from non-net metered DG resources. This is greater than the amount that utilities will have to pay net metered customers for RECs. Thus in a high net metering growth scenario, utilities incur less cost to meet Tier 2 obligations than they do in a low net metering growth scenario. Conversely, higher compliance cost scenarios will feature lower net metering growth and a consequently larger Tier 2 obligation that utilities must meet by acquiring new DG resources.

Effect of Tier 3 Electrification on Tier 1 and Tier 2 Obligations

Several eligible Tier 3 measures are potential sources of new load for utilities.[4] The RES model allows the user to specify which Tier 3 measures utilities will incentivize to meet their obligations.[5] If utilities are assumed to

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[3] The baseline electricity sales forecast in the RES model is derived from the load forecast developed by VELCO for the upcoming 2018 Long Range Transmission Plan (LRTP). Information about the LRTP can be found at: https://www.vermontspc.com/.

[4] Tier 3 measures are represented in the RES Model consistent with the characterizations in the Technical Reference Manual (TRM).The TRM is developed and maintained by the Technical Advisory Group (TAG), of which the PSD is a member. Since the establishment of the RES in 2015, the TAG has been developing calculations that prescribe the amount a given Tier 3 measure will be credited toward a DU's Tier 3 obligation, informed by a variety of primary and secondary empirical and engineering studies.

[5] The current version of the RES model only includes cold climate heat pumps and electric vehicles as Tier 3 compliance measure options, both of which are load-building measures. While PSD anticipates that much of the Tier 3 savings over the next couple years will come from custom measures at commercial facilities, these opportunities are extremely site specific and difficult to take advance inventory of for modeling purposes.

incentivize Tier 3 measures that build electric load, their retail sales will be higher and they will have to acquire more Tier 1 and Tier 2 RECs to meet their obligations. For example, a single passenger electric vehicle that displaces a standard internal combustion engine might use around 3.3 MWh per year. In a scenario where utilities rely exclusively on electric vehicles for Tier 3 compliance, this would amount to around 12,600 new EV's on the road by the year 2027, and a total of 42,300 MWh of new load that is not in the baseline load forecast. By statute, 67 percent of these 42,300 new MWh would have to be supplied with renewable resources. In contrast, if utilities exclusively incentivized non-electric Tier 3 measures, like biofuel burning equipment or efficiency upgrades, they would not have to acquire any RECs to cover incremental loads.

Tier 3 Compliance Cost Components

Incentive Payments

Fossil fuel price levels influence how large a customer incentive utilities will need to provide in order to spur adoption of Tier 3 measures.[6] In general, the larger the gap between the cost to own and operate standard fossil fuel equipment (furnaces, boilers, internal combustion engines, etc.) and the cost to own and operate a substitute Tier 3 measure, the larger the financial incentive the utility will have to provide to the customer. For example, if the price of fuel oil used for home heating purposes is assumed to be \$2.00 per gallon, around 20% lower than prices in recent years, a household that expects such low prices to continue would likely need a substantial financial incentive to induce an investment in a heat pump (somewhere in the range of \$800 to \$1,200 by PSD's calculations). If instead, fuel oil prices are assumed to be \$3.00 per gallon, around 20% higher than in recent years, many customers may not need to be financially incentivized to invest in a heat pump at all.[7]

The RES model allows for different assumptions about the future price environment of fossil fuels. In the scenarios analyzed by PSD for this report, three possibilities were explored: a base case assuming current fossil fuel prices will persist in real terms over the next ten years, and high price and low price cases that assume future prices will be 20% higher or 20% lower than they are today and stay at those levels (in real terms) over the next ten years. The low fossil fuel price case scenarios feature significantly higher utility incentive payments than the high fossil fuel price case scenarios.

Program Administration Overhead

Utilities will likely incur new costs to design, administer and document their Tier 3 programs. The scenarios PSD analyzed for this report assumed these costs would total \$200,000 in the first year and rise thereafter with inflation. This sum represents a small share of the total compliance expenditure in any scenario. PSD will not have a reliable sense of the accuracy of this assumption until the Tier 3 performance evaluation process is completed. Future reports will provide opportunities to refine overhead cost assumptions with verified, historical information.

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[6] The RES gives utilities the option of meeting Tier 3 obligations by retiring Tier 2 RECs in excess of their Tier 2 obligation. None of the scenarios analyzed by PSD for this report assume utilities will follow this course; although the Department expects that some amount of excess Tier 2 RECs will be used for this purpose, it is likely to be relatively minor component of Tier 3 compliance.

[7] This is not to say that PSD believes a high fossil fuel price environment will automatically trigger widespread investments in relatively cheaper renewable and electric alternatives, since many businesses and households may lack the income, capital or liquidity to retool simply because business as usual became more expensive.

Cost to Serve New Tier 3 Loads

If the Tier 3 measures incentivized by utilities are sources of new electric load, utilities will incur additional costs to supply and deliver that power to customers. The RES model captures three distinct cost of service categories relating to new Tier 3 loads, each of which can be assumed to grow more or less expensive over the projection period: 1) energy costs, 2) capacity costs, and 2) regional transmission costs. These categories represent only the wholesale side of the cost to serve Tier 3 loads. There will likely also be retail level costs associated with Tier 3 loads that utilities will have to recover from ratepayers, but the current version of the RES model does not capture these.[8] The incremental costs incurred by utilities in each of these categories is determined primarily by the assumed operational performance of the Tier 3 equipment. If the Tier 3 equipment is assumed to operate mostly during peak periods, wholesale electricity costs will be higher than if the Tier 3 measure is assumed to avoid adding to peak demand. Supposing Tier 3 loads do not add significantly to peak demand, the increase in electricity consumption can exert a moderating effect on upward rate pressure associated with the cost to comply with the RES. This is because Tier 3 loads increase the volume of sales over which utilities recover their costs. However, if the incremental cost to serve new Tier 3 loads is high because equipment is disproportionately operated during times of peak demand, Tier 3 loads will intensify upward rate pressure caused by compliance with the RES.

[8] This would be true if, for example, incremental Tier 3 load exceeds local circuit and substation capacities, necessitating an upgrade investment by utilities. However, given the small potential total volume of new Tier 3 load, such upgrade investments are unlikely to be widespread occurrences.

I. Summary of Program Performance to Date

Pursuant to the PUC's *Order Implementing the Renewable Energy Standard*, issued in Docket 8550 on June 28, 2016, the utilities are required to submit filings by August 31 documenting their compliance with the prior year's RES requirements. After reviewing these filings, the PUC will issue an order verifying utility compliance, currently expected by December 15, 2018. Utilities must demonstrate compliance with Tiers 1 and 2 of the RES by retiring sufficient quantities of RECs in the NEPOOL GIS, which closes its accounting period for the prior year on June 15. Additionally, utilities must submit compliance claims for Tier 3 to PSD by March 15. The Department is responsible for evaluating and verifying utility Tier 3 performance and, by June 1, must provide a conclusion to the PUC of as to the accuracy of the utilities' fossil fuel reduction claims.

Based on ongoing discussions with utilities, PSD does not expect utilities will have much difficulty meeting any of the 2017 RES requirements. With a significant amount of already committed renewable resources in their portfolios—in the form of both utility-owned generation and long-term bilateral contracts—utilities have a reliable supply of Tier 1 RECs at their disposal. Likewise for Tier 2, PSD expects that ongoing growth in net metering and continued commissioning of standard offer projects is likely to supply sufficient RECs to satisfy all or most of the utilities' 2017 obligations. With respect to Tier 3, several utilities have developed custom projects to meet their first year of obligations, including extending power to saw mills and maple sugaring operations currently dependent on diesel or gasoline generators. Additionally, most of the utilities have developed programs offering incentives for cold climate heat pumps (CCHP) and electric vehicles (EV).

II. Expectations of Future Program Performance

In 2015, Vermonters directly consumed around 94,000,000 MMbtu of fossil fuel energy for end-use purposes, primarily heating buildings and fueling vehicles. This represents around three quarters of Vermont's total consumption of "on-site," or "end-use" energy.[9] Additionally, through their usage of electricity, Vermonters indirectly consumed around 25,000,000 MMBtu of fossil fuel that was used up in the power generation process.[10] Meeting the RES Tier 3 requirements implies ongoing reductions in direct fossil fuel consumption (or end-use consumption) of several tens of thousands of MMBtu each year. Similarly, meeting the Tier 1 and Tier 2 requirements implies ongoing reductions in utility procurement of non-renewable source energy of a couple hundred thousand MMBtu per year.[11] After 10 years of this trajectory, PSD estimates that end-use consumption of fossil fuels will be lower by between 600,000 and 900,000 MMBtu. To be sure, this is a modest reduction in

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[9] The distinction between site energy and source energy is important when measuring a quantity of energy consumption that includes electricity. The energy content of electricity may be characterized as a site measurement, which includes only the energy delivered to the end-user, or as a source measurement, which in addition, includes the upstream energy used in the generation process. For example, there are 3,412 Btu of energy in a kWh consumed on-site by an end-user. If that kWh was produced by a fossil fuel burning power plant, several thousand more Btu would have been consumed in the combustion process that generated the 3,412 Btu of consumable electricity. A source measurement of the energy content of a kWh generated with fossil fuels could amount to 7,000 to 10,000 Btu.

[10] This total includes all renewable energy for which utilities did not retain RECs. On top of this 25,000,000 MMbtu of fossil generation fuel, Vermont consumes around 770,000 MWh of nuclear power. Because nuclear generators do not operate by burning fuel it is difficult to attribute a discrete amount of source energy to the power they produce. For energy accounting purposes, it is common to assign a fossil fuel equivalent energy content to the electricity produced by nuclear plants. Doing so for Vermont's power supply portfolio equates to an additional 8,000,000 MMbtu of non-renewable energy that can be added to the 25,000,000 MMbtu of fossil generation, amounting to a total current consumption of non-renewable source energy of approximately 32,000,000 MMbtu.

[11] This assumes utilities meet their Tier 3 requirements through "energy transformation" projects rather than retiring excess Tier 2 RECs or making alternative compliance payments (ACP).

overall fossil fuel end-use—less than 1 percent lower than current levels. There will be much more significant reductions in consumption of source fossil energy, which will be lower by more than 10,000,000 MMBtu, a reduction of around 40% relative to current levels. Overall, across all energy using sectors, PSD estimates that Vermont will consume around 10% less fossil-based energy in 2027 than it does today because of DU compliance with the RES. Similarly, carbon dioxide emissions could be lower by between 600,000 and 700,000 tons, a reduction on the order of 10% relative to recent levels (estimated to be in the range of 7,000,000 to 8,000,000 tons).

Using the RES model, PSD estimates that the total incremental cost utilities will incur to meet all RES requirements over the next ten years (2018-2027) will most likely fall within a range between $94,000,000 and $134,000,000 (expressed in 2018 dollars). In the highest cost scenarios analyzed by PSD, the total ten year RES compliance cost ranged as high as $200,000,000, though PSD currently considers this a low likelihood outcome. In the RES model, there are six distinct compliance cost categories:

1) Tier 3 incentives paid by utilities to customers,
2) Tier 3 program administration overhead expenses,
3) the cost for utilities to serve new load associated with customer adoption of Tier 3 measures,
4) the cost for utilities to acquire RECs from net metered (NM) customers,
5) the cost for utilities to acquire RECs from renewable distributed generation resources (DG) to meet Tier 2 obligations, and,
6) the cost for utilities to comply with Tier 1 requirements through REC purchases.

The table below presents what PSD currently considers the most likely value ranges for each of these compliance cost categories (expressed in 2018 dollars), listed alongside a description of the key variable in the RES model that determines the subtotal.

	Low Incremental Cost	High Incremental Cost	Key Determinant
Tier 1	$4,000,000	$5,000,000	REC price levels
Tier 2	$80,000,000	$96,000,000	LCOE for DG
Tier 3			
Incentives	$6,500,000	$23,000,000	Fossil Fuel prices
Overhead	$2,000,000	$2,000,000	N/A
New Load	$1,500,000	$8,000,000	Equipment Peakiness
Total	$94,000,000	$134,000,000	

A significant amount of the disparity between the upper and lower bounds in the above table can be explained by the prevailing fossil fuel price environment assumed in each scenario. If fossil fuel prices fall to and remain at historically low prices over the next ten years, utilities will likely have to pay higher incentives to entice customers to transition toward fossil fuel alternatives like cold climate heat pumps and electric vehicles. This possibility is reflected in the high end of the Tier 3 incentive cost range ($23,000,000). The low end of the cost range for Tier 3 incentives ($6,500,000) reflects the effects of a high fossil fuel price environment, where the customer economics of fuel switching toward electricity and other alternatives is more favorable, necessitating less incentive payments from utilities.

How these volumes of compliance expenditures will translate into a change in retail electricity rates depends largely on two factors: 1) the extent to which utilities meet Tier 3 obligations by incentivizing measures that increase electricity consumption and, more critically, 2) the costs that utilities will have to pay to bring new DG into their power supply portfolios in order to acquire Tier 2 RECs.

All else equal, to the extent that utilities comply with Tier 3 obligations by incentivizing load-building measures like heat pumps and electric vehicles, upward rate pressures associated with RES compliance will be lower than if utilities choose to incentivize Tier 3 measures that don't increase electricity end-use, like biofuel-burning equipment or efficiency upgrades. This is because with increased electricity consumption, the costs of meeting the RES requirements can be spread across a greater volume of unit sales. For example, if utilities were to rely exclusively on a mix of heat pumps and electric vehicles to meet Tier 3 obligations, by 2027 they would be selling between 20,000 and 45,000 more MWh of electricity. Relative to today's approximately 5,500,000 MWh of electricity consumption, this is not a large increment of sales with which to absorb what could turn out to be a substantial increase in utility costs. Nonetheless the extra load provides a meaningful moderating effect on upward rate pressures. All scenarios PSD analyzed for this report exhibited upward rate pressure. In the scenarios PSD considers most likely, the rate increase attributable to the RES ranged from 0.60% to 1.15% percent higher than a baseline rate path on average over the next ten years. In the less probable, highest cost scenarios, the long-term rate impact averaged as much as 2.0% higher. All of these percentage increases would be slightly higher without the incremental load from Tier 3 measures, by as much as a third of a percentage point.

The higher compliance cost scenarios analyzed by PSD for this report assume that all heat pumps and electric vehicles counted toward the utilities' Tier 3 obligations will add load during times of peak demand. This would naturally be the case if a heat pump is operated without custom operational programming or time-of-use controls, or if vehicle charging routinely begins soon after work hours end. On the other hand, if it is assumed that heat pump and electric vehicle loads come online without adding at all to peaks, it is conceivable, however unlikely, that utility compliance with the RES would exert no upward rate pressure on net.

Any such neutral rate impact outcome would depend almost entirely on a rather unlikely continuation of the strong recent downward trend in the cost of power produced by DG resources, a factor largely outside of utilities' control (unlike, for example, the implementation of controls on Tier 3 equipment, which utilities do have some influence over). Tier 2 compliance costs is the largest driver of utility compliance expenditures because the cost of DG significantly exceeds the cost of the wholesale power (largely fossil-fuel generated) that would otherwise fill the utilities' portfolios. Recent experience with the Standard Offer program and current market research suggests that utilities should continue to be able to meet their near-term Tier 2 obligations at a levelized cost of energy (LCOE) in the range of $100 to $120 per MWh (at least for wind and solar resources); and industry consensus still appears to expect declining DG costs, though at a more moderate pace than observed in recent history. PSD does not expect that the costs of DG will continue to decline so significantly that the relatively small potential amount of new Tier 3 load would be sufficient to alleviate all upward pressure on retail rates; this would require sustained year-over-year decreases in the LCOE of DG of 10% or more.

On balance, PSD anticipates the RES will exert some upward long-term pressure on retail electric rates. But whatever actual RES compliance costs turn out to be, it is certain that ratepayer costs will be lower if utilities take the initiative to ensure all new Tier 3 loads come online as flexible demand side resources, capable of avoiding adding to existing levels of peak demand. To illustrate this point, a heat pump or electric vehicle that draws large amounts of power from the grid during peak times might cost the utilities as much as several hundred dollars per MWh consumed by the equipment. This is significantly more than the current retail rate of roughly $155 per MWh (and would thus contribute to upward rate pressure). If those same technologies can avoid loading the grid at peak times though, it might only cost utilities $30 to $50 per MWh consumed by the equipment, low enough to check the majority of upward rate pressure associated with the procurement of DG power that is expected to cost $100 to $120 per MWh.

Conclusion

Although compliance data is not yet available, the Department's modelling suggests the RES will produce meaningful reductions in fossil-fuel usage and greenhouse gas emissions. If utilities choose to meet Tier 3 requirements with measures that increase electric load and they are able to minimize peak usage of these technologies, the increased consumption of electricity will spread utility costs over a greater volume of sales, mitigating the upward pressure on rates associated with RES compliance expense.

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Appendix I – Statutory Reporting Requirement

§ 8005b. Renewable energy programs; reports

(a) The Department shall file reports with the General Assembly in accordance with this section.

(1) The House Committee on Commerce and Economic Development, the Senate Committees on Economic Development, Housing and General Affairs and on Finance, and the House and Senate Committees on Natural Resources and Energy each shall receive a copy of these reports.

(2) The Department shall file the report under subsection (b) of this section annually each January 15 commencing in 2018 through 2033.

(3) The Department shall file the report under subsection (c) of this section biennially each March 1 commencing in 2017 through 2033.

(4) The provisions of 2 V.S.A. § 20(d) (expiration of required reports) shall not apply to the reports to be made under this section.

(b) The annual report under this section shall include at least each of the following:

(1) An assessment of the costs and benefits of the RES based on the most current available data, including rate and economic impacts, customer savings, technology deployment, greenhouse gas emission reductions actually achieved, fuel price stability, and effect on transmission and distribution upgrade costs, and any recommended changes based on this assessment.

(2) Projections, looking at least 10 years ahead, of the impacts of the RES.

(A) The Department shall employ an economic model to make these projections, to be known as the Consolidated RES Model, and shall consider at least three scenarios based on high, mid-range, and low energy price forecasts.

(B) The Department shall make the model and associated documents available on the Department's website.

(C) In preparing these projections, the Department shall:

(i) characterize each of the model's assumptions according to level of certainty, with the levels being high, medium, and low; and

(ii) provide an opportunity for public comment.

(D) The Department shall project, for the State, the impact of the RES in each of the following areas: electric utility rates; total energy consumption; electric energy consumption; fossil fuel consumption; and greenhouse gas emissions. The report shall compare the amount or level in each of these areas with and without the program.

(3) An assessment of whether the requirements of the RES have been met to date, and any recommended changes needed to achieve those requirement

Appendix II – Key Assumptions

The table below documents the key input assumptions in the scenario analyses that produced PSD's compliance cost and rate impact projection ranges for what it considers most likely high and low cost scenarios (see *Expectations of Future Program Performance*). All dollar figures are expressed in nominal terms, averaged over the projection period. Low and high fossil fuel price levels are relative to a base case assumption that escalates current prices at the assumed rate of inflation. The cost to serve Tier 3 load does not capture possible local transmission or distribution capital expenses or other retail-level costs. Vermont peak is defined as the six hours ending 17 through 22. New England peak is defined as the six summer hours ending 14 through 19. Wholesale power costs are inclusive of energy charges, capacity charges and regional network service charges. PSD has constructed the below scenarios to represent what it considers realistic worst and best case possibilities.

	Higher Rate Impact	Lower Rate Impact
General Assumptions		
Inflation Rate	+1.9%	+1.9%
Customer Discount Rate	10.0%	6.0%
Tier 3 Load Profile	Peaky	Controlled
Net Metering Production	+10%/yr	+20%/yr
Energy Price Assumptions		
Fossil Fuel price scenario	low (-20%)	high (+20%)
Fossil Fuel price trend	< inflation	+3.0%/yr
Wholesale power cost trend	-0.5%/yr	+2.0%/yr
Tier 1 REC price trend	+2.0%/yr	flat
Distributed RE cost trend	+2.0%/yr	-2.0%/yr
Tier 3 Assumptions		
Residential Heat Pump		
Average T3 Credit Value	24 MWh	24 MWh
Annual Electricity Usage	+2.2 MWh	+2.2 MWh
Contribution to VT peak	+3 kW	0 kW
Contribution to NE peak	+2 kW	0 kW
Equipment Cost Year 1	$3,000	$3,000
Equipment Cost Trend	inflation	flat
Average Incentive Amount	$1,300	$200
Average Cost to Serve Load	~$450/yr	~$95/yr
Passenger Electric Vehicle		
Average T3 Credit Value	37 MWh	37 MWh
Annual Electricity Usage	+3.3 MWh	+3.3 MWh
Contribution to VT peak	+3 kW	0 kW
Contribution to NE peak	+3 kW	0 kW
Equipment Cost Year 1	$35,000	$35,000
Equipment Cost Trend	inflation	-3.0%/yr
Average Incentive Amount	$2,300	$800
Average Cost to Serve Load	~$680/yr	~$110/yr