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January 15, 2019

Members of the Vermont General Assembly
115 State Street
Montpelier, VT 05633-5301

Re: Annual Report on the Renewable Energy Standard

Dear Senators and Representatives,

I am pleased to submit a report on the historical and ongoing impacts of the Renewable Energy Standard, conducted pursuant to 30 V.S.A. § 8005b. This report includes an assessment of the costs and benefits of RES to date, projected impacts of RES going forward, and an assessment of RES compliance to date.

If you have any questions or concerns upon reading this report please do not hesitate to contact me or the Director of Energy Policy and Planning, Ed McNamara.

Very truly yours,

June E. Tierney
Commissioner

2019 Annual Report on the Renewable Energy Standard

Vermont Department of Public Service

January 15, 2019

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 historical and ongoing impacts of the Renewable Energy Standard (RES).

The annual report, as set forth in subsection (b) of Section 8005b[1], must address three issues:

1. An assessment of costs and benefits of the RES based on the most current available data;
2. Projected impacts of the RES on electric utility rates, total energy consumption, electric energy consumption, fossil fuel consumption, and greenhouse gas emissions; and
3. An assessment of RES compliance to date.

The first section, *Summary of Program Performance to Date,* is retrospective in nature; it evaluates the historical performance of the RES program with respect to its costs and benefits. The second section, *Projections of Future Program Performance,* is prospective in nature; it summarizes the results of modeling exercises undertaken by PSD in projecting the impacts of RES on Vermont, given historical information and current trends. The final section, *RES Compliance,* presents an assessment of whether the RES requirements have been met to date.

The report also includes a methodology section, *Methodology and RES Model Overview*, and two appendices. The methodology section describes the mechanics of the model that was used to support the quantitative projections. 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 the State's electricity supply and the electrification of both transportation and heating. PSD estimates that Vermonters will reduce fossil fuel consumption over the next 10 years by a total of 128,000,000 mmBtu, and carbon dioxide (CO_2) emissions by 6,000,000 to 7,000,000 tons as a direct result of the RES.

- All Vermont Distribution Utilities (DUs) met the 2017 RES requirements. Compliance costs for 2017 were approximately $5.4 million. PSD estimates the cost of continuing to meet RES obligations over the next ten years will have a net present value (NPV) cost of between $10,000,000 and $174,000,000. This estimate includes the expectation that Tier 3 of RES will lower compliance costs to some degree by increasing revenues from higher electric sales. Given the large quantity of RECs required for compliance, a relatively small difference in REC prices can result in a large difference in costs. PSD expects the Tier 1 requirement in 2017 to be over 3,000,000 RECs, so a $7/MWh change in market prices translates to an additional $21,000,000 in compliance costs for that single year.

- The primary drivers of utility compliance expenditures include REC prices, net-metering adoption rates, Tier 3 incentive costs, and whether new load increases peak loads. The high-versus-low REC price forecast results in a 1.8% difference in rate impacts. The high-versus-low net-metering deployment forecast results in a 2.2% difference in rate impacts. If new load from Tier 3 measures including cold climate heat pumps (CCHPs) and electric vehicles (EVs) are deployed without controls that enable customers to avoid adding to peak demand, the rate impact would be about 0.7%.

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

- There will likely be upward electricity rate pressure associated with RES. PSD estimates that retail rates will be between 0.6% and 3.1% higher over the next ten years as a result of RES and could be 5% higher if certain unlikely circumstances were to materialize.

Overview of RES and Reporting Requirement

Section 8 of Public Act No. 56 of 2015 (Act 56) directed the Public Utility Commission (PUC) to implement a renewable energy standard, by means of "an order, to take effect on January 1, 2017". This requires Vermont's DUs to acquire and retire a minimum quantity of renewable energy attributes or Renewable Energy Credits (RECs), and to achieve fossil-fuel savings from energy transformation projects.[2] The structure of the RES is divided into three tiers.

Tier 1 requires DUs to retire qualified RECs or attributes from any renewable resource to cover at least 55% of their annual retail electric sales starting in 2017. This amount increases by 4% every third January 1 thereafter, up to 75% in 2032. A utility can also make an Alternative Compliance Payment (ACP) in lieu of retiring Tier 1 RECs.

Tier 2 requires DUs to retire qualified RECs equivalent to 1% of their annual retail sales starting in 2017. Tier 2 eligible resources include renewable generators with a nameplate capacity of less than 5 MW, commissioned after June 30, 2015, and connected to a Vermont distribution or subtransmission line. The Tier 2 requirement increases by three-fifths of a percent each year, up to 10% in 2032. Like Tier 1, a utility can make an ACP in lieu of retiring Tier 2 RECs. Pursuant to Section 8005(a)(1)(C), Tier 2 resources also count towards a DU's Tier 1 requirement. Additionally, to the extent that a DU is 100% renewable, the DU is not required to meet the annual requirements set forth in Tier 2 but is required to accept net-metering systems and retire the associated RECs.[3] [4]

The implementation of REC retirements for RES Tier 1 and Tier 2 compliance brings Vermont in line with the rest of the New England states. Starting in 2003, other states in the region began implementing renewable portfolio standards (RPS). By 2008, all other states in region had an RPS to be met with REC retirements or an ACP. During that time, Vermont encouraged renewable development through the Sustainably Priced Energy Enterprise Development (SPEED) program but did not require utilities to serve their load with renewable energy or to retire RECs. The use of RECs to track renewability has become the generally accepted standard across the country.

Act 56 also created Tier 3, which requires DUs to achieve fossil-fuel savings from energy transformation projects or retire Tier 2 RECs. For Tier 3, the RES requires savings of 2% of a DU's annual retail sales in 2017 increasing to 12% by 2032, except for municipal electric utilities serving less than 6,000 customers, which have a delayed start and no obligation until 2019. Energy transformation projects implemented on or after January 1, 2015 are eligible to be counted towards a DU's Tier 3 obligation. A utility can also make an ACP in lieu of achieving sufficient fossil fuel savings or retiring Tier 2 RECs. ACP payments are made to the Clean Energy Development Fund (CEDF), which "promotes the development and deployment of cost-effective and environmentally sustainable electric power

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[2] 30 V.S.A. § 8005(b).

[3] Net metering RECs must be retired per Section 5.127(B)(1) of Rule 5.100 and 30 V.S.A. § 8010(c)(1)(H)(ii)

[4] A REC is the renewable attribute associated with a MWh of generation from a qualified renewable resource. With each MWh of electric generation, an environmental attribute is also created. An eligible renewable resource can qualify its generation in different states such that attributes associated with that resource receive a "REC" designation. The energy (MWh) and attributes (RECs) can be separated and traded independent of each other so that a DU can achieve RES compliance by purchasing RECs and does not necessarily need the physical energy from the renewable resources. RECs are the currency used to demonstrate renewable energy compliance in all New England states. NEPOOL Generator Information System (NEPOOL GIS) is the platform used in New England that tracks the characteristics of all generators in the region. It is in this system that all RECs in the region are created, traded and retired.

and thermal energy or geothermal resources for the long-term benefit of Vermont consumers."[5] Energy transformation projects include weatherizing buildings, installing air source or geothermal heat pumps, biomass heating systems and other high-efficiency heating systems, switching industrial processes from fossil fuel to electric, increased use of biofuels, and deployment of electric vehicles or related charging infrastructure. The Tier 3 requirements are additional to the Tier 1 requirements and an ACP option is available for Tier 3 compliance.

Methodology and RES Model Overview

To project the impacts of RES, the Department developed a spreadsheet-based scenario-analysis tool, the Consolidated RES model or RES model. This tool is capable of modeling a range of assumptions regarding energy and REC price, net-metering deployment, technologies used to meet Tier 3 requirements, and the impact of new Tier 3 load on peaks.[6] The RES Model is not a forecasting tool, but instead is designed to facilitate a bounding exercise for reasonable best and worst case scenarios. This section provides a high-level explanation of the key relationships that determine the different assumption-dependent results reported below in the prospective section of this document, *Projections 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.

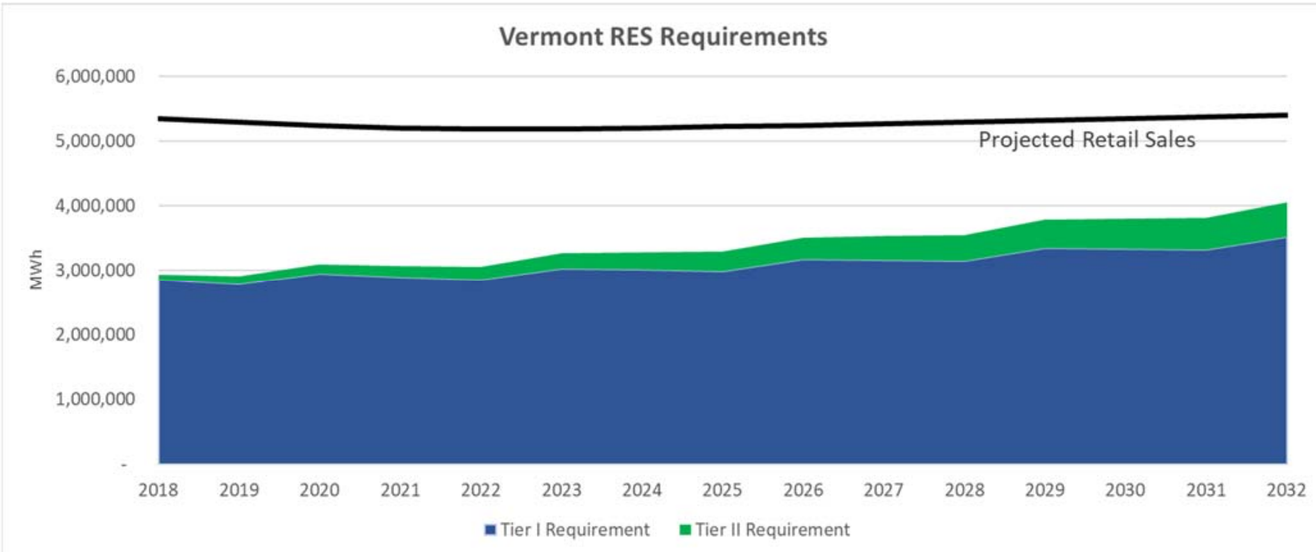
The main output of the RES model, for any given set of assumptions, is a calculation of the total incremental utility expenditure required and resulting rate impact to comply with the RES requirements over the next ten years. This compliance cost can be mapped to each tier of RES. The costs of Tier 1 and Tier 2 compliance are determined primarily by the amount that utilities are assumed to pay in order to acquire RECs from eligible renewable generation resources, including net-metered and Standard Offer projects. The cost of Tier 3 compliance includes incentives paid by utilities to encourage customer adoption of fossil fuel reduction measures, program administration overhead, and the cost to serve any new electric load associated with customer adoption of fossil fuel reduction measures, less the revenue received from additional retail sales.

Loads

RES obligations are based on a utility's retail sales in the compliance year. The load forecast used in the RES model is based on the 2018 VELCO Long-Range Transmission Plan (LRTP) less new net-metered generation plus additional load from Tier 3 measures.[7] The baseline forecast was developed by aggregating monthly regression model forecasts for each customer class. The VELCO net-metering forecast assumes continued high deployment rates in the near-term that slow in the long-term as the market becomes saturated. The PSD's projections use the VELCO forecast as the base-case assumption, but alternative scenarios to reflect higher and lower net-metering deployment have also been developed. Additional load from Tier 3 measures is dependent on the assumptions regarding the technologies deployed to achieve Tier 3 fossil fuel reductions. For example, a future where weatherization is the primary tool used to meet Tier 3 requirements will have a lower load forecast than a future that targets thermal and transportation electrification with cold climate heat pumps (CCHP) and electric vehicles (EV).

[5] 30 V.S.A. § 8015(c).
[6] The RES Model is available on the Department's website at: http://publicservice.vermont.gov/publications-resources/publications
[7] The LRTP can be found at: https://www.velco.com/assets/documents/2018%20LRTP%20Final%20_asfiled.pdf. Further information can be found at: https://www.vermontspc.com/.

Based on the forecasted loads, Tier 1, 2 and 3 requirements forecasts follow. The chart below shows Vermont's projected retail sales and RES requirements through 2032.



Tier 1 and Tier 2 Compliance Costs

Utilities must retire RECs to demonstrate Tier 1 and Tier 2 compliance. Absent sufficient RECs, an ACP must be paid to the Clean Energy Development Fund. The RES Model makes assumptions about the price utilities will pay to procure RECs. Tier 1 and Tier 2 requirements can be met with RECs acquired in a variety of ways, including:

1. Net-metered projects that transfer RECs to the utility;
2. Standard Offer projects, where RECs are transferred to the Standard Offer Facilitator and then to DUs;
3. Utility-owned renewable generation;
4. Long-term "bundled" (e.g. energy, capacity and RECs) Power Purchase Agreements (PPA); and
5. REC-only market purchases.

As previously described, for each MWh of generation from qualified renewable resources, a REC is also created. Utilities may obtain RECs from net-metering projects, standard-offer projects, ownership of utility-scale resources, long-term PPAs, or REC-only purchases. Current net-metering rates provide a significant financial incentive for customers to transfer the RECs to the utility, such that most net-metering projects going forward are expected to transfer their RECs to the utility, which thus will be counted towards Tier 2 compliance. Given the recent pace of net-metering adoption, many utilities expect to meet most, or all, Tier 2 compliance needs for the next five years with RECs from net-metering projects. Standard-offer projects, from which utilities are required to purchase their pro-rata load share (except DUs that are exempt)[8] also include Tier 1 and/or Tier 2 RECs. Additionally, several utilities also own or have existing contracts to purchase the output from Tier I and/ or Tier 2 qualified generators. If a utility does not have sufficient RECs to cover its obligation, in the near-term, PSD expects sufficient excess RECs will be available for purchase at prices lower than the ACP.

[8] Pursuant to 30 V.S.A. § 8005a(k)(2)(B), a DU may be exempt if "the amount of renewable energy supplied to the provider by generation owned by or under contract to the provider, regardless of whether the provider owned the energy's environmental attributes, was not less than the amount of energy sold by the provider to its retail customers."

REC markets provide the opportunity to obtain RECs without having to make a long-term commitment of purchasing or generating physical power. However, REC markets can be volatile and illiquid. The ACP, or the price paid when insufficient RECs are retired acts as a price ceiling for trading prices. The Tier 1 ACP was $10/REC and Tiers 2 and 3 were $60/REC in 2017; each will escalate annually with CPI.

Tier I resources include any renewable generator in ISO-NE and imports from neighboring control areas (e.g., Hydro Quebec, New York Power Authority hydro). This category of RECs has consistently been in excess supply since the inception of renewable standards in the region, as there is no requirement that the eligible resources be new or limited to a certain size. Tier I RECs have traded at a wide range of prices from about $0.75/ REC to $10.00/REC in 2017[9]. The Department expects utilities will be able to meet most of their obligations over the next 10 years with the RECs produced by their owned resources, those they are entitled to by long-term contracts, and the balance from short-term REC only purchases. The RES Model includes three REC price forecasts. The Tier 1 base case assumes an average price of around $2.60/REC, with prices starting at $1/REC in 2018 and increasing to about $5/REC by year 2027. The low case remains flat at $1/REC, and the high case averages $7/REC for 10 years.

Tier 2 of the RES defines eligible resources as renewable generators with a nameplate capacity of less than 5 MW, commissioned after June 30, 2015, and connected to a Vermont distribution or subtransmission line. These narrow criteria will be a limiting factor on tradable Tier 2 REC supply going forward and will likely result in Vermont Tier 2 RECs trading at a premium to other comparable REC markets in the region. The Department expects there to be limited opportunity for utilities to purchase unbundled Tier 2 RECs. Instead, most Tier 2 RECs will come from net-metering, standard-offer, utility-owned resources, and long-term bundled purchases. In the near term, Tier 2 obligations are expected to be met mostly with net metering[10] and standard-offer RECs, and the balance will likely trade at prices very similar to Massachusetts and Connecticut Class I markets. However, looking further out, as RES requirements increase and cannot be met with net-metering and standard-offer projects alone, additional RECs will be needed to meet the requirements and greater price separation between Vermont and other states may emerge because only a subset of the total New England REC supply qualifies as Vermont Tier 2. The Tier 2 base-case price forecast assumes an average price of around $20/REC for Tier 2 RECs with prices starting at $7/REC in 2018 and increasing to $24/REC by year 2027. The low-case averages $12/REC, and the high-case averages $36/REC for 10 years.

RES allows for the banking (of up to 3-years) of excess RECs to then be used for compliance in future years; however, for simplicity, the Department's analysis disregards banking and assumes that excess RECs in a given year will be sold at market prices to offset total compliance costs. By not fully modelling the banking of RECs, the cost of RES is overstated due to the steep upward slope of forecasted REC prices where utilities are expected to sell excess RECs in the near-term at low prices, then acquire RECs in future years at higher prices.

In the RES model, total compliance costs for Tiers 1 and 2 are calculated as the product of the assumed cost per REC and the total utility obligation (MWh). The utility obligation quantity is determined by applying the pertinent statutory percentage to the annual retail sales forecast. Much of Vermont's Tier 1 obligation will be satisfied with RECs from existing long-term purchases from Hydro-Quebec (HQ) and New York Power Authority (NYPA) that come at no additional cost. The forecasted Tier 1 REC price is then applied to the balance of the obligation.[11] A

[9] Not all Tier I traded RECs were used for Vermont compliance; Tier I RECs are generally qualified in other New England states and used for compliance outside of Vermont.

[10] Net metering RECs must be retired per Section 5.127(B)(1) of Rule 5.100 and 30 V.S.A. § 8010(c)(1)(H)(ii)

[11] Tier 1 obligations are expected to be met with RECs from owned and purchased renewables. It is assumed that absent RES, utilities would sell the RECs from owned generation at the associated price so the cost represents the lost opportunity of REC revenue.

similar method was applied to Tier 2 costs, with expected RECs from net metering being assigned the REC adjustor spread, standard offer RECs assigned a $25/REC price[12], and the balance (purchases or sales) assigned Tier 2 price forecast. Assuming all else equal, when the load forecast is higher, it follows that the obligations are higher, and therefore compliance costs will also be higher. The factors that significantly impact obligations and costs are REC prices, net metering deployment and the extent to which utilities comply with Tier 3 obligations with measures that increase electric load.

Effect of Net-Metering on Obligations and Costs

Customer-sited generation (also referred to as "net-metered") reduces the volume of electricity that utilities would otherwise sell to ratepayers. Generally, high net-metering deployment leads to higher costs. Larger volumes of generation from net-metering results in lower load and lower RES obligations, but also lower retail sales revenues and more RECs from high-priced net-metering projects. As outlined in PUC rule 5.100, in 2017, net-metered customers received $0.06 per kWh ($60 per MWh) more for their generation when they transfer their RECs to the host utility, compared to if the customer decides to retain the RECs. [13] 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, which will then be used towards Tier 2 obligations. RECs from net-metering customers reduce the amount of RECs that utilities would have otherwise acquired from other sources, which would generally carry a lower cost. Further, because most DUs expect to have excess Tier 2 RECs and REC forecasts are currently low, revenues from the sale of excess RECs will be minimal. From a DU power supply perspective, net-metering generation can be very difficult to forecast in large part due to changing rules and tax credits; therefore, many DUs, in preparation for RES, invested in Tier 2-eligible projects or entered into long-term bundled PPAs and now have an excess of Tier 2 RECs that need to be sold into MA or CT REC markets. Over the course of the past year, REC prices have plummeted, so while DUs are acquiring net-metered RECs at $60/REC, they are selling equivalent RECs for less than $10/REC. In the scenarios analyzed by PSD for this report, RECs from net-metering generation are more expensive than RECs from other sources and in excess of what will be needed for Tier 2 obligations.

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

Several eligible Tier 3 measures offer sources of new load for utilities.[14] The RES model allows the user to specify which Tier 3 measures utilities will incentivize to meet their obligations. [15] If utilities are assumed to incentivize Tier 3 measures that build electric load, their retail sales will be higher and thus their Tier 1 and Tier 2 obligations will also be higher. For example, a single passenger electric vehicle that displaces a standard internal combustion engine might use around 2 MWh per year. In a scenario where utilities rely exclusively on electric vehicles for Tier 3 compliance, this would amount to over 140,000 new EV's on the road between 2018 and 2027, and a total of 286,000 MWh of new load that is not in the baseline load forecast. Offsetting higher Tier 1 and 2 costs for utilities

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[12] This represents the estimated imputed price between the wholesale energy and capacity value and the PPA price paid to the generator.

[13] The PUC ordered a decline in the REC adjustor for projects built after 7/1/2018, and another decrease to the REC adjustor is scheduled for projects built after 7/1/2019.

[14] 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.

[15] The current version of the RES model includes CCHPs, EVs, weatherization and custom projects as Tier 3 compliance measure options. For all projections, the technology allocation has been kept constant.

are additional retail revenues from increased electric sales. In contrast, if utilities exclusively incentivized non-electric Tier 3 measures, like biofuel burning equipment or weatherization upgrades, Tier 1 and Tier 2 obligations will be unaffected.

PSD has assumed the following constant allocation of technologies will be used to meet Tier 3 requirements in each year of the projections:

Tier 3 Technology Allocation	
Cold Climate Heat Pumps	30%
Electric Vehicles and Charging Stations	35%
Weatherization	15%
Custom	15%
Tier II RECs	5%

This allocation is intended to be a proxy for the State over 10 years, but each utility will have a different allocation of measures based on its territory and customers' needs that will change over time. The Department does not expect this to be the actual allocation in each year, but in an effort to quantify the associated additional load and costs, this illustrative allocation of measures was developed. In the first year of compliance, about 70% of obligations were met with custom measures and about 25% with heat pumps; however, over the next 10 years, custom projects will likely become more difficult to identify and the electrification of transportation, including commercial scale, is expected to ramp up. With the current calculation method for Tier 3 credits where a heat rate is applied to fossil-fuel offset measures, utilities have not focused on weatherization because the credits are discounted, and no additional load is gained.

Tier 3 Compliance Cost Components

Incentive Payments

Fossil-fuel price levels and project incentives influence customer adoption of Tier 3 measures. In general, consumers act rationally, and the benefits of a Tier 3 measure must outweigh the costs to justify the investment. When fossil fuel prices are low, then the cost to own and operate standard fossil fuel equipment (furnaces, boilers, internal combustion engines, etc.) is also low relative to the cost to own and operate a substitute Tier 3 measure. Therefore, in a low fossil-fuel price environment, utilities may need to offer a greater financial incentive to encourage Tier 3 measures. Conversely, when fossil fuel prices are high, so too is the cost to operate traditional fossil fuel equipment relative to alternative Tier 3 measures, and customers may not need as significant of a financial incentivize to invest in a Tier 3 measure.

The RES model allows for different assumptions about the future price 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 by 2027, prices will be 55% higher or 10% lower than they are today. The low fossil-fuel price scenario features utility incentive payments that are 30% higher than the base case, while the high fossil-fuel price case scenarios decreases incentives by 25%.

Program Administration Overhead

Utilities will 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 2018, escalating by 3% thereafter. This represents a small share of the total compliance expenditure in any scenario. In the early stages of RES, program costs may have significant year-over-year changes as experience will lead to gains in efficiency as the programs mature, but programs that capture low-hanging fruit will dry up. Future reports will provide opportunities to refine overhead cost assumptions with historical information.

Costs and Revenues of 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, which may be offset by higher retail sales. The RES model captures the cost of service for new load in energy, capacity, and regional transmission costs. The incremental costs to provide capacity and transmission is determined by the operations of the Tier 3 equipment. If Tier 3 equipment increases peak loads, capacity and transmission costs will be incurred, increasing the cost to serve. Conversely, Tier 3 loads that are controllable or do not add to peak demand will have much lower costs associated with them. From a policy perspective, most new load associated with Tier 3 measures should be controllable and not increase peak loads so that they will help to offset other RES compliance costs. The RES model includes a variable to test the financial implications of how Tier 3 affects peak loads; the scenario resulting in the low incremental cost of RES assumed no additional peak load, and the high incremental cost scenario assumed 90% of new load would add to the peak.

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, Vermont utilities were required to submit the first annual RES filings by August 31, 2018 documenting compliance for 2017. On December 10, 2018, the PUC issued an order in Docket 17-4632 concluding that all Vermont utilities met their 2017 RES requirements. Utilities demonstrated compliance with Tiers 1 and 2 of the RES by retiring RECs in the NEPOOL GIS, which closed its accounting period for 2017 on June 15, 2018, or paid an ACP to the CEDF. Due to an oversight, one utility was one Tier 1 REC short of its compliance requirement, resulting in a $10 payment to CEDF for the 2017 compliance period. Additionally, utilities submitted Tier 3 compliance claims to PSD on March 15; the Department evaluated Tier 3 performance and presented those findings in a Tier 3 Report filed on June 1, 2018.

All utilities met the 2017 RES requirements. Tier 1 was met with RECs from a variety of resources including owned hydro facilities, long-term Hydro-Quebec purchases, and regional hydro REC only purchases, among others. In 2017, Tier 2 was satisfied with continued growth in net metering, commissioning of standard offer projects, and in-state solar, both utility and merchant owned. With respect to Tier 3, obligations were met with a variety of measures including programs to promote the adoption of cold climate heat pumps, electric vehicles, electric vehicle charging stations, weatherization, and wood heat. Additionally, several utilities developed custom projects to meet their first year of obligations which were both cost effective and delivered significant fossil-fuel savings, while other DUs met portions of their Tier 3 obligation with the retirement of Tier 2 RECs. Custom projects included extending electric lines to saw mills and maple sugaring operations previously dependent on diesel or gasoline generators.

Key metrics summarizing 2017 RES performance are included in the table below:

2017 RES Performance		
Tier I REC retirements	3,355,501	RECs
Tier II REC retirements	49,934	RECs
Tier III lifetime MWh savings	99,839	Mwhe[16]
Cost of RES Compliance	$5,450,000	
Rate Impact of RES Compliance[17]	0.6%	
CO2 Reduction from RES	579,000	tons of CO2

Compliance costs for 2017 were estimated to be about $5.5 million, compared to maximum potential costs of $38.5 million.[18] Carbon Dioxide (CO2) emissions were reduced by approximately 579,000 tons from 2016

[16] MWhe is the nomenclature for MWh equivalent for Tier 3 savings claims.
[17] The rate impact is based on the 2017 total cost of service of $874,434,047 (https://publicservice.vermont.gov/sites/dps/files/Annual_Reports/kWh_Density_Reports/2017%20KWH%20%20Revenue%20Rankings%207-18-18%20post%20Correction%20to%20Morrisville.pdf)
[18] Maximum potential costs reflect what the costs would have been if ACP was paid for all compliance in 2017.

emissions.[19] This shift to more renewables brings Vermont's average emissions rate down to 205 pounds of CO2 compared to the regional New England average of 682 pounds per MWh in 2017.[20]

With only one year of experience, it is too early to draw any conclusions about the overall economic impacts, customer savings, fuel price stability, and effects on transmission and distribution upgrade costs. The Department will continue to monitor each of these areas as the program matures.

II. Projections of Future Program Performance

In 2016, Vermonters directly consumed around 103,000,000 mmBtu of fossil-fuel energy for heating buildings and transportation. [21] Additionally, Vermonters indirectly consumed around 22,000,000 mmBtu of fossil fuel through electric usage.[22] Meeting the RES Tier 3 obligations requires 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. At this trajectory, PSD estimates that end-use consumption of fossil fuels resulting from Tier 3 will be about 2,700,000 mmBtu in 2027. This is a modest 2% reduction in overall fossil fuel end-use. There will be much more significant reductions in consumption of source fossil-fuel energy from the greening of Vermont's electric mix, which will be lower by 14,000,000 mmBtu in 2027, a reduction of 60% relative to 2016 levels.[23] Overall, across all energy using sectors, PSD estimates that by 2027 Vermont will consume around 13% less fossil-based energy than it does today as a direct result of RES. Similarly, carbon dioxide emissions could be reduced by 900,000 tons in 2027, a reduction on the order of 12% relative to recent levels (estimated to be in the range of 7,000,000 to 8,000,000 tons).

Using the RES model, PSD finds there to be a wide range of credible outcomes of the total incremental cost of the RES requirements over the next ten years (2018-2027). Costs could be as low as $8 million (NPV), or as high as $172 million. The primary cost drivers in the model are:

1) Tier 1 and Tier 2 REC prices,
2) Net-metering deployment rates and costs,
3) Tier 3 incentives paid by utilities to customers, and
4) the cost to serve new load associated with Tier 3 measures.

The table below summarizes what the PSD considers credible ranges for each compliance tier over the next 10 years.

[19] Emissions reductions for 2017 are based on Vermont's overall power supply portfolio that included 63% renewable and 13% nuclear, both of which are zero emissions; the remaining 24% is assumed to have the ISO-NE marginal emissions rate of 842 lbs/MWh. The 2016 Vermont emissions assumed roughly 52% of Vermont's load was served by system mix energy at the marginal emissions rate. Tier 3 credits are based on lifetime savings, but when calculating emissions, only annual emissions offsets are considered, making the Tier 3 contribution to emissions reductions minimal in 2017.

[20] http://isonewswire.com/updates/2018/12/20/regional-air-emissions-2017-long-term-reduction-trends-conti.html

[21] http://eanvt.org/wp-content/uploads/2018/06/EnergyActionNetwork_AR_2017_AA_final.pdf

[22] Based on 52% of load from ISO-NE residual mix at an average heat rate of 8,000 mmbtu/MWh

[23] Much of Tier 1 and Tier 2 savings are a result of purchasing RECs from existing resources, so while Vermont is reducing its fossil fuel consumption, the region overall has not added any incremental renewable energy.

	HIGH INCREMENTAL COST	LOW INCREMENTAL COST
REC Price Forecast	HIGH	LOW
NM Deployment Rate	HIGH	LOW
Peak contribution of New Load	90%	None
Fossil Fuel Price	LOW	HIGH
Tier 1 Cost	$136,000,000	$20,000,000
Tier 2 Cost	$63,000,000	$48,000,000
Tier 3 Net Cost	-$25,000,000	-$58,000,000
TOTAL Cost of RES	**$174,000,000**	**$10,000,000**
Rate Impact	4.92%	0.63%

The most significant difference between the upper and lower bounds in the table above is related to Tier I REC prices. PSD expects Tier 1 compliance costs to be around $50 million over the course of 10 years, but changes to renewable policies in neighboring states can alter the supply and demand landscape and have significant price implications. Tier 2 costs are most impacted by net metering deployment and to a lesser extent REC prices. The fossil fuel price environment has a significant impact on Tier 3 costs. 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.

All else equal, to the extent that utilities comply with Tier 3 obligations by incentivizing load-building measures like heat pumps, electric vehicles, and other custom electrification projects, upward rate pressures associated with RES compliance will be lower than if utilities incentivize non-load building Tier 3 measures such as weatherization or biofuel-burning equipment. With increased electricity consumption, the costs of meeting the RES requirements can be spread across a greater volume of unit sales and will dampen the rate impacts. For example, if utilities were to rely exclusively on heat pumps to meet Tier 3 obligations, by 2027 they would be selling an additional 375,000 MWh of electricity. This additional load represents almost 7% of current retail sales (about 5,500,000 MWh annually) and has a meaningful moderating effect on upward rate pressures if the new load does not contribute to peak loads. All scenarios PSD analyzed for this report resulted in upward rate pressure. In the scenarios PSD considers most likely, the rate increase attributable to the RES ranged from 0.6% to 3.1% 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 4.8% higher.

The higher compliance cost-scenarios analyzed by PSD for this report assume that 90% of all new electric load resulting from Tier 3 measures will add load during times of peak demand. This could be the case if heat pumps and electric vehicle charging do not have custom operational programming or time-of-use controls. 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 that utility compliance with the RES would exert no upward rate pressure, on net.

Overall, PSD anticipates the RES will exert slight 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 ensure all new Tier 3 loads come online as flexible demand-side resources that do not add 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 $180 per MWh (and would thus contribute to upward rate pressure). This does not account for the fact that increases in peak could also result in increased distribution and subtransmission costs. 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.

III. RES Compliance

On December 10, 2018, the PUC issued an order in Docket 17-4632 concluding that all Vermont utilities met their 2017 RES requirements. At this time, no changes to the requirements are recommended.

Conclusion

One year of RES compliance experience, combined with the Department's modelling, suggests the RES will have moderate rate impacts while producing meaningful reductions in fossil-fuel usage and greenhouse gas emissions. If utilities meet Tier 3 requirements with measures that increase electric load and do not contribute to peak loads, 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.

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 *Projections of Future Program Performance*). 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. 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 scenarios.

	Higher Rate Impact	Base Case Assumptions	Lower Rate Impact
General Assumptions			
Inflation Rate	+1.9%	+1.9%	+1.9%
Customer Discount Rate	6.0%	6.0%	6.0%
Tier 3 Load Profile	90% Peak Contribution	25% Peak Contribution	No Peak Contribution
Net Metering Deployment	385 MW by 2027	350 MW by 2027	275 MW by 2027
Tier I REC Price	Avg $7.20 /MWh	Avg $2.60/MWh	Avg $1.00/MWh
Tier 2 REC Price	Avg $35.90 /MWh	Avg $20.40/ MWh	Avg $12.40/MWh
Energy Price Assumptions			
Fossil Fuel price scenario	Low	Base	High
Fossil Fuel price trend	-1%/yr	1.6%/yr	+5.0%/yr
Wholesale power cost trend	-1.2%/yr	1.4%/yr	+4.9%/yr

Appendix III – Snapshots from the Model

<u>Assumuptions Tab</u>

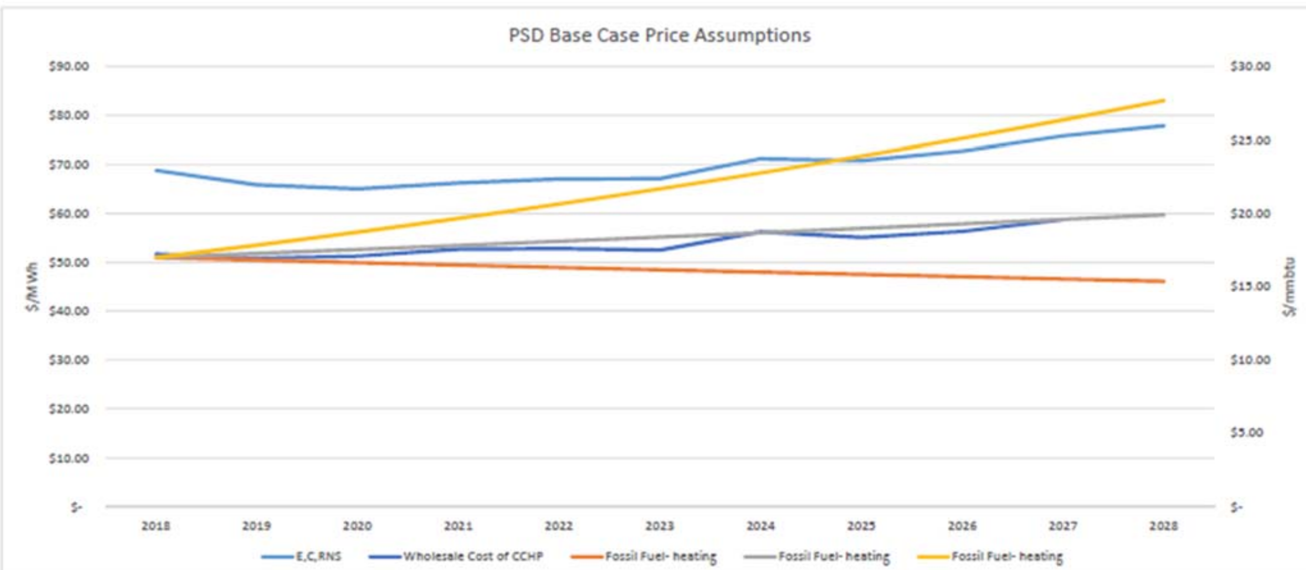
Assumption Level of Certainty	ASSUMPTIONS	PSD BASE CASE	HIGH SCENARIO	LOW SCENARIO
	base year	2018	2018	2018
high	inflation rate	1.90%	1.90%	1.90%
high	customer discount rate	6%	6%	6%
high	depreciation rate	-1%	-1%	-1%
low	NM Escalation Rate	VELCO	HIGH	LOW
mid	REC Scenario	MID	HIGH	LOW
mid	residential electricity rate ($/MWh)	$ 179	$ 179	$ 179
mid	retail electricity price trend	2.2%	2.2%	2.2%
low	Fossil Fuel Scenario	MID	LOW	HIGH
	Low Fossil Fuel escalation	-1%	-1%	-1%
	Mid Fossil Fuel escalation	1.6%	1.6%	1.6%
	High Fossil Fuel escalation	5%	5%	5%
mid	**<u>Tier III Technology Allocation</u>**			
	CCHP	30%	30%	30%
	EV	35%	35%	35%
	Weatherization	15%	15%	15%
	Custom	15%	15%	15%
	Tier II RECs	5%	5%	5%
	TOTAL	100%	100%	100%
	<u>Tier III BASE Incentive Rates ($/claimed MWh)</u>			
	CCHP	$ 25.0	$ 25.0	$ 25.0
	EV	$ 30.0	$ 30.0	$ 30.0
	Weatherization	$ 20.0	$ 20.0	$ 20.0
	Custom	$ 12.0	$ 12.0	$ 12.0
	<u>Tier III Incentive Escalation</u>			
	CCHP	0%	0%	0%
	EV	0%	0%	0%
	Weatherization	0%	0%	0%
	Custom	15%	15%	15%
	Tier II RECs	0%	0%	0%
	CCHP LMP multiplier	1.05	1.05	1.05
	EV LMP multiplier	0.97	0.97	0.97
	Weatherization multiplier	1	1	1
	Custom multiplier	1	1	1
	Tier III contribution to RNS peaks	0.25	0.9	0
	Tier III contribution to FCM peaks	0.25	0.9	0
	Tier III Overhead in Year 1	$ 200,000	$ 200,000	$ 200,000
	Tier III Overhead escalation	3%	3%	3%

Annual Base Case Output Results

PSD BASE CASE	TOTAL	2018	2019	2020	2021	2022
TOTAL Cost of RES	$64,582,481	$ 7,683,767	$ 9,331,597	$ 10,081,415	$ 9,961,674	$ 9,411,383
Rate Impact	2.91%	2.22%	3.12%	3.58%	3.77%	3.67%
Total Energy Consumption Impact (mmbtu)	(10,003,372)	(215,834)	(340,632)	(486,274)	(652,387)	(838,836)
Electric Energy Consumption Impact (MWh)	1,037,702	18,451	31,450	46,889	64,739	84,976
Electric Energy Consumption Impact (%)	2.0%	0.35%	0.60%	0.90%	1.26%	1.67%
Total Fossil Fuel Consumption Impact (mmbtu)	(128,665,186)	(9,006,717)	(9,315,248)	(11,313,464)	(11,634,260)	(11,923,947)
Total lbs of CO2 Saved	14,144,840,508	958,758,942	998,841,373	1,218,192,451	1,262,405,757	1,304,742,845
Total tons of CO2 Saved	6,417,804	435,009	453,194.82	552,719	572,779	591,989

	2023	2024	2025	2026	2027
TOTAL Cost of RES	$ 9,000,980	$ 8,358,630	$ 7,394,355	$ 7,968,484	$ 7,844,895
Rate Impact	3.43%	2.91%	2.41%	1.98%	1.48%
Total Energy Consumption Impact (mmbtu)	(1,046,799)	(1,276,991)	(1,489,878)	(1,711,803)	(1,943,938)
Electric Energy Consumption Impact (MWh)	107,677	132,921	157,254	183,021	210,323
Electric Energy Consumption Impact (%)	2.12%	2.62%	3.11%	3.63%	4.17%
Total Fossil Fuel Consumption Impact (mmbtu)	(13,859,255)	(14,148,660)	(14,420,595)	(16,376,518)	(16,666,523)
Total lbs of CO2 Saved	1,521,723,653	1,566,962,077	1,609,189,847	1,829,283,799	1,874,739,764
Total tons of CO2 Saved	690,437	710,963	730,122	829,984	850,608

Base Case Price Assumptions



REC Price Assumptions