2021 Annual Energy Report

A summary of progress made toward the goals of Vermont's Comprehensive Energy Plan

Prepared by the Vermont Department of Public Service

January 15, 2021

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I. Overview

Vermont's energy policy, as articulated in statute, is:

> To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.[1]

The three goals – reliability, affordability, and sustainability – can at times be in competition. Any policy actions should acknowledge this and should also be informed by objective data as to Vermont's existing energy usage and policies. This Annual Energy Report is designed to provide that objective data and also provide transparency regarding how this data informs the policies pursued by the Public Service Department (PSD or the Department).

The 2016 Comprehensive Energy Plan

Vermont's CEP, which is published every six years by the Department of Public Service, is designed to "implement the State energy policy set forth in section 202a" and be consistent with the relevant land use planning goals contained in 24 V.S.A. § 4302. The 2016 CEP contains an overarching goal of meeting 90% of the state's energy needs with renewable energy across the electric, thermal, and transportation sectors by 2050. In addition to the 90% by 2050 goal, the CEP contains many sector-specific goals, as summarized below.

Figure 1: 2016 Comprehensive Energy Plan Goals

Sector	Goal
Total Energy	90% renewable by 2050
	40% renewable by 2035
	25% renewable by 2025
	Reduce consumption per capita by 15% by 2025 and by more than 33% by 2050
Electricity	67% Renewable by 2025
Thermal	30% Renewable by 2025
Transportation	10% Renewable by 2025
Greenhouse Gases	40% below 1990 levels by 2030
	80-95% below 1990 levels by 2050

A significant component of reaching the goals set forth in the CEP is the reduction in energy use across all sectors. The scale of reduction would not be consistent across all sectors – Vermont's electric sector

[1] 30 V.S.A. § 202a.

has had great success reducing consumption through energy efficiency, but will not be able to reduce per-capita electric usage by a third, particularly with the necessary shift to electric vehicles and heat pumps. Instead most of the total energy reduction will come from the transportation and heating sectors through efforts to move away from inherently inefficient combustion technologies and toward electric vehicles and cold climate heat pumps.

The 2016 CEP also contains illustrative pathways that could be taken in order to reach the goals outlined above. For example, one such pathway is the installation of 35,000 cold-climate heat pumps by 2025. These pathways, while helpful to understand the rate and scope of change needed to reach our goals, should not be interpreted as the intended or only possible pathways to reach those goals. Planning documents must recognize that technological changes, markets, and other forces will impact how we proceed into the future and which path we take to reach our goals. Dictating specific technologies now can limit more cost-effective options in the future. Conversely, waiting for the best possible technological shift or market change can result in the goals never being met. Good planning requires an eye towards what the future may bring while simultaneously striving to meet goals within the present context. Planning goals should inform and drive policy choices and not simply be a soundbite that is used to promote a particular narrative.

Moving Forward to Meet the 2016 CEP Goals

As described in detail in this report, Vermont is surpassing the 2016 CEP renewable goals for the electric sector; however, achieving significant transformation of the transportation and heating sectors continues to pose challenges.

The success in the electric sector is in large part due to the structure of the electric industry. To the extent that mandates are imposed upon the electric utilities, the utilities, as monopolies, are able to recover from electric customers the reasonable costs of meeting these mandates. In the past, the costs of several important state policies have been embedded in electric rates. Now more than ever, this approach should be used sparingly and targeted toward policies that increase the affordability, sustainability, and reliability of Vermont's electricity infrastructure. The prospects for achieving important state policy goals – such as growing the economy and substantially reducing greenhouse gas reductions through electrification – depend on guarding against upward rate pressures.

Electric rates are based on the cost to provide service and the electric costs paid by a customer are based on consumption. Many Vermonters are struggling economically due to the pandemic and imposing costs through rates rather than through taxes (which can be based on income), and funding efforts that utilize electric rates can disproportionately impact low- and moderate-income Vermonters. Additionally, increased cost pressure on electric rates has the effect of making it more difficult to decarbonize the transportation and heating sectors, which account for the vast majority of the greenhouse gas emissions in Vermont. Information on household spending on energy – electric, heating, and transportation, is included as Appendix C of this report.

The 2016 CEP renewable goals for the transportation and heating sectors are heavily dependent on electrification technologies – such as moving from inefficient internal combustion engines to electric vehicles. However, this move to electrification technologies is not a government mandate and is dependent on customers choosing electric vehicles over traditional cars and/or choosing to install cold climate heat pumps or advanced wood heating to reduce the use of heating oil and propane. For most customers, these choices are informed not only by environmental considerations but also by economics. Customers are more likely to adopt electric vehicles and heat pumps when the fuel costs – in this case electricity – are reasonable compared to the alternative fossil fuel costs. Progressive rate designs can and should be developed to provide lower rates for certain end-use technologies; however, electric costs must still be recovered and electric rates must be set to ensure that all Vermonters are able to benefit from the move toward a cleaner economy.

This report does not attempt to address every energy-related program, but instead provides a broad examination of Vermont's progress toward the 2016 CEP goals and the impediments to achieving 90% renewable goals in an equitable and affordable manner. There are a number of appendices to this report that provide more detailed information, including Appendix A – a Summary of Energy Programs and Services Offered in Vermont, and Appendix D – a Report on Renewable Energy Standard.

II. Greenhouse Gas Emissions

In addition to statutory goals, the CEP sets forth specific goals for reducing GHG emissions in all sectors. As with the CEP generally, GHG reductions can be achieved through reduced energy usage and switching to renewable sources for the remainder of the necessary energy.

This section of the report provides an overview of: (1) the GHG reduction requirements in statute and the 2016 CEP GHG reduction goals; (2) the progress on meeting these targets; and (3) an analysis of the relative cost-effectiveness of different policy measures in achieving carbon reductions.

Greenhouse Gas Reduction Requirements

In 2020, the Vermont legislature passed the Global Warming Solutions Act (GWSA),[2] which established requirements to reduce greenhouse gas emissions "from within the geographical boundaries of the State and those emissions outside the boundaries of the State that are caused by the use of energy in Vermont"[6] by:

(1) not less than 26% from 2005 GHG emissions by January 1, 2025;

(2) not less than 40% from 1990 GHG emissions by January 1, 2030; and

(3) not less than 80% from 1990 GHG emission by January 1, 2050

In addition, the GWSA established a Climate Council to review measures and develop a Climate Action Plan to achieve the GHG emission reduction requirements.[3]

Progress on Meeting GHG Requirements

Vermont's Agency of Natural Resources, through its Air Quality and Climate Division, provides annual estimates on the amount of greenhouse gas emissions (GHG) by sector.[4] The Vermont Greenhouse Gas Emissions Inventory and Forecast (GHG Inventory) provides very useful data that should be incorporated into any discussion regarding energy policy. The most recent update to the GHG Inventory was included in the 2020 Annual Energy Report; however, it is expected that there will not be significant changes from the last available information – the electric sector represents a relatively small portion of Vermont's GHG emissions, and the thermal and transportation sectors contribute approximately 75% of Vermont's GHG emissions.

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[2] Act 153 of 2020, available at: https://legislature.vermont.gov/Documents/2020/Docs/ACTS/ACT153/ACT153%20As%20Enacted.pdf.

[3] For further information, please see: https://aoa.vermont.gov/content/vermont-climate-council.

[4] See, Department of Environmental Conservation, Vermont's Greenhouse Gas Emissions, available at: https://dec.vermont.gov/air-quality/climate-change.

Relative Costs of Carbon Reduction

There are many state programs that support Vermont's efforts to reduce GHG emissions across the different sectors, including renewable power supply requirements, energy efficiency, weatherization, advanced wood heating, and incentives for electric vehicles and cold climate heat pumps. These programs use a mix of public and private investment to lower emissions and incur both public and private costs and savings. The Department created a tool to better understand how particular actions ("measures") reduce carbon emissions relative to the costs and benefits of each action.
This simplified spreadsheet model compares efficiency, transportation, and renewable energy measures by estimating the amount of carbon savings relative to the economic cost to Vermont as a whole over the measure's life. Measures with negative "net costs" are effectively "net benefits." Other important emissions reduction policies, such as improving bicycle and pedestrian infrastructure and increasing public transit use, are not included given the difficulty of estimating emissions reductions on a per-measure basis.

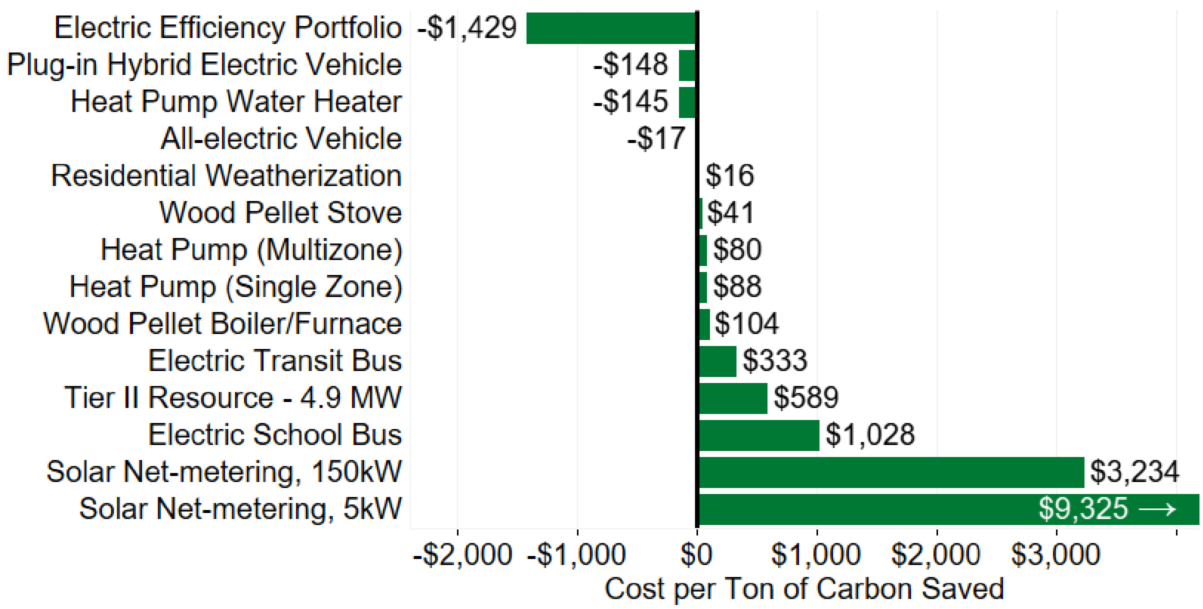
The measures analyzed often provide additional benefits besides carbon reduction, including economic development, health benefits, and improved comfort in weatherized homes. The model does not attempt to capture these additional benefits because they are not already quantified for each and every measure. The model is not an argument to expand or eliminate certain programs, but instead intended to compare the carbon impacts of existing clean energy measures. The Department supports continuing a diverse approach to mitigating carbon emissions; such a portfolio approach provides customers with choices and ensures lower cost strategies are accessible as technologies improve and prices fall.

The tool uses readily available data and estimates, meaning that only select measures are included. Data and assumptions were developed in 2019 and updated in fall 2020. The model accounts for electricity-related emissions based on the Vermont utilities' power supply mix after attribute trading and adjusted to reflect the changes to the power supply mix over a measure's lifetime.

The chart below depicts the measures analyzed, ranked occurring to the cost per ton of carbon avoided. A negative cost means that benefits outweigh costs; in other words, the measures save money over their lifetime. A positive cost means that the financial costs of the carbon-reducing measure outweigh the financial benefits. The summary does not differentiate who bears the cost and includes incremental expenditures and savings whether these are borne by individuals (e.g., buying equipment) or Vermonters at large (e.g., lower electricity costs).

Additional information about the methodology is available in Appendix B.

Figure 1 - Relative Cost of Carbon Reduction Policies



Generally, efficiency measures such as electric efficiency and weatherization programs are more cost-effective than measures that require significant upfront expenditures. Some of the measures analyzed have high initial costs and are not widely deployed. For such measures, it is important to remember that it is useful to trial new technologies, particularly in the areas of transportation and heating where electrifications efforts are relatively nascent, new approaches to decarbonization are needed, and technology costs will likely continue to decline.

III. Strategies for Reaching 90 by 2050

Reducing demand

Over the past decade, electric efficiency and conservation have more than offset the increase in energy demand associated with increases in population, the growth in building-space square footage, and the growth in industrial output. Efficiency, defined as doing the same amount of work with less energy input, remains Vermont's first option to meet energy requirements – in both the building (electric and thermal) and transportation sectors. Traditional efficiency programs have served Vermont well over the last several decades. Over the last several years, fuel switching technologies such as electric heat pumps and plug-in or all-electric vehicles allow the same level of energy services with much less site energy requirements, while also allowing for sourcing of the energy renewably. Together, both traditional efficiency and cost-effective fuel-switching are critically important to meet both Vermont's energy and GHG reduction goals and requirements.

Traditional electric efficiency programs remain cost-effective, but achievable efficiency potential is declining. Vermont needs to continue to acquire all reasonably available electric potential, while maintaining stability in programs and rates charged to support investment. In addition, innovation remains paramount – as we invest in efficiency, we can identify opportunities to further pursue

Vermont's goals. For example, the Public Utility Commission recently approved an Efficiency Vermont proposal to, while in a building recommending efficiency investments, identify opportunities to reduce greenhouse gas emissions from leaks of high Global Warming Potential refrigerants. It is these types of efficiencies in service delivery that must continue to be pursued.

The electric sector has seen sustained investments in efficiency, in part as a result of a dedicated funding source for programs – the Energy Efficiency Charge (EEC) that is set by the PUC. To date, there has not been a similar dedicated and controllable funding source directed to efficiency measures in the transportation and thermal sectors.

In the thermal sector, weatherization programs encourage participants to invest in efficiency, and support for low-income Vermonters comes from Weatherization Assistance Programs (see Chapter X for a summary of the state's weatherization programs). In addition to the energy savings for the participant and the emissions savings for the State, the PSD along with the Agency of Commerce and Community Development ("ACCD") recently estimated that every dollar invested leads to approximately two dollars in GDP growth. These investments make economic sense.

In addition, the health benefits of efficiency are becoming more and more clear. For example, in 2018 the Vermont Department of Health published a report showing that the "health and safety benefits of basic weatherization are most often either byproducts of energy efficiency improvements . . . or are otherwise necessary as a prerequisite to providing other weatherization services."[5] The desired energy outcomes of weatherization programs are inextricably intertwined with the desired health outcomes of Vermont's health care providers. Through further proving these connections Vermont can break down these silos to create opportunities to reduce costs for Vermonters in both sectors.

The funding for these programs is not sufficient to encourage necessary weatherization utilizing the current suite of available programs. Regulation must foster a competitive marketplace and rely less on direct incentives (or rely on lower incentives) while facilitating innovative solutions from a wide array of actors. Particularly given the economic uncertainty associated with the ongoing pandemic, it is a challenge to fund up front investments that will pay off over many years. In addition, and as described above, electric costs must be carefully managed, to avoid a potential counterproductive effect of increases in short-term costs slowing electrification efforts - customers will be more hesitant to invest in electrification technologies if the cost of electricity is higher than the fossil fuel cost. Instead, new sources of private capital and customer financing options must continue to be leveraged and explored.

In the transportation sector, reducing vehicle miles traveled is a critical first step, consistent with Vermont settlement patterns and smart land use policy, as well other demand management activities such as mass transit, walking, biking, and telework. This requires sufficient infrastructure including broadband to enable telecommuting, increased mass transit, bike lanes, etc.

Electrification

Strategic electrification – such as moving from internal combustion engines to electric vehicles or replacing in whole or in part fossil powered thermal or process loads with electricity – is a core component of the State's energy plan. Done strategically, these electro-technologies can reduce and/or stabilize consumer costs while providing the energy service with less – or even no – emissions impact. Strategic electrification also provides an opportunity to make more efficient use of the electric

[5] *Weatherization + Health. Health and Climate Change Co-Benefits of Home Weatherization in Vermont.* Vermont Department of Health, December 2018. https://www.healthvermont.gov/sites/default/files/documents/pdf/ENV_CH_WxHealthReport.pdf.

infrastructure currently in place. To enable electrification and ensure that it is in the consumer's interest, policy and regulatory changes have been and continue to be necessary.

The core policy and regulatory mechanism currently supporting strategic electrification is "Tier 3" of the Renewable Energy Standard. As described in this report, Tier 3 requires electric utilities to reduce fossil fuels from their customers, providing flexibility to the utilities to achieve their targets in the most cost-effective manner consistent with long standing least cost principles. The primary measures implemented pursuant to this mechanism has been to provide incentives for electro-technologies. In the thermal sector, for example, incentives for heat pumps, combined with incentives from Efficiency Vermont to ensure the heat pump is the most efficient for the customer, have led to approximately 10,000 heat pumps installed in 2020, a significant increase from prior years. This critical partnership has been encouraged to promote efficiency first – as noted above, efficiency remains Vermont's most cost-effective resource – and to gain administrative efficiencies by leveraging current infrastructure. The structure of the coordination is such that it avoids monopolies providing competing and overlapping service, maintaining a single entity as the decision-maker to direct the course of service activity and ensure maximum statewide impact. In the transportation sector, distribution utilities have provided incentives for electric vehicles through their Tier 3 programs. Line extensions removing diesel generation from sugarhouses and sawmills, and other technologies such as electric fork-lifts have also been supported, creating a comprehensive list of supported technologies. See Appendix A for more details.

Additional action in the transportation sector has also taken place outside of Tier 3. The distribution utility Tier 3 incentives have been supplemented with significant incentives from the State, to further lower the up-front cost of vehicles. Other supporting regulations and market interventions have been put in place as well, such as Electric Vehicle Supply Equipment build out, signage, and rate designs to lower operational costs (while still maintaining just and reasonable distribution of cost across ratepayers). Act 151 of 2020, created following a Public Utility Commission (PUC) report, supports limited use of efficiency funds to support transportation efficiency.[6] The Act pilots a mechanism that will allow efficiency utilities to supporting dealers and manufacturers to further increase electric vehicle adoption – an area that was identified as a gap in the PUC study. The details of these programs are expected to be considered by the Public Utility Commission early in 2021.

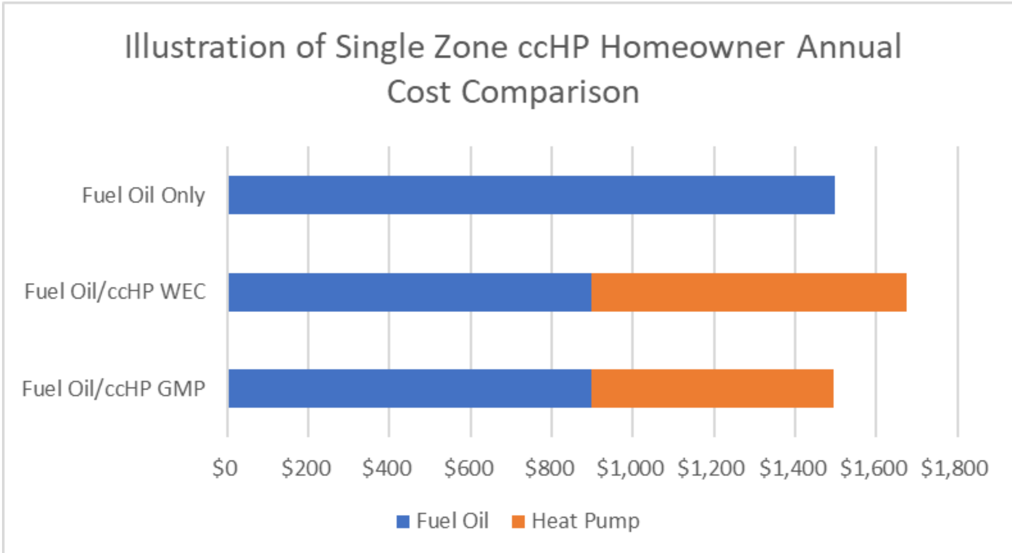
Many of the electrification incentives described above help address the market barrier associated with the upfront cost of a customer installing an electrification measure. This is because the move to electro-technologies, for many customers, are informed not only by environmental considerations, but also by economics (in addition to other factors such as comfort). Customers are more likely to adopt electric vehicles and heat pumps when the fuel costs – electricity – are reasonable compared to the alternative fossil fuel costs. Progressive rate designs can be developed to provide lower rates for certain end-use technologies; however, these rates must still be set to ensure just and reasonable rates. *To the extent that policies center on the electric sector and power supply costs, there will be further rate pressures that risk undermining progress in those sectors that contribute the lion's share of GHG emissions. Electric costs must remain low in order to ensure an effective transition to electrification.*

The importance of customer cost is illustrated in Figure 2, a comparison of the annual operating costs of a heat pump of a home heated by fuel oil (assumed for these purposes to be $2.50 per gallon – higher than the price at time of writing), with one that installs a heat pump (with an assumed coefficient of performance of 2.5) that replaces 40% of the heat load in the home, for customers served by Green

[6] Act 151 of 2020, available at: https://legislature.vermont.gov/Documents/2020/Docs/ACTS/ACT151/ACT151%20As%20Enacted.pdf.

Mountain Power (GMP) and Washington Electric Coop (WEC). Performance and energy costs will be different at any given time and for any given customer.

Figure 2 - Heat Pump Cost Example



As can be seen in Figure 2, at $2.50/gallon for fuel oil and the current rate, this particular heat pump would save little cost for a GMP customer and cost more on an annual basis for a WEC customer. This analysis only looks at operating costs and does not include the upfront costs of installing a heat pump. However, customers may choose the heat pump for different reasons, including the ability to add air conditioning during the summer, and emissions reductions. Notwithstanding these additional factors, the cost for the customer will impact the rate of adoption of these electro-technologies.

Electric rate design can help by reducing the cost of electricity for that particular end-use technology. Vermont residential consumers pay a retail electric rate that typically ranges from 16 to 23 cents per kWh (lower for some municipalities); this rate, in addition to the monthly customer charge, reflects the full costs of providing electric service to the customer including power supply, tree trimming, maintenance, borrowing costs, billing, etc. The power supply costs are less than the full retail price, and new, flexible loads that provide grid services could be served at a lower cost than full retail rate while ensuring that participating customers are not subsidized by non-participating customers.

Load Management

Rate design is just as critical to minimize infrastructure costs. As discussed further in section X on load management, the addition of uncontrolled electrification could cause the need for infrastructure upgrades. But properly managed, additional flexible loads can better utilize the existing system without increasing peaks and necessitating costly infrastructure upgrades. This is not a new concept, as many Vermont utilities have historically offered special prices to customers in exchange for load control. Innovative rate designs that continue to reduce cost pressures for all customers are critical to facilitating strategic electrification.

The increased communications capability enables more precisely controlled distributed resources. However, this capability is not ubiquitous in Vermont – many areas of the state do not have reliable broadband necessary to ensure communication between customers with devices (such as electric vehicles or heat pumps) that are controllable and the utility that is coordinating the charging and usage of these devices. A key component of the move toward greater load management, and therefore decreased infrastructure costs, is continued efforts on broadband deployment.

In 2020, the Department coordinated a U.S. Department of Energy-supported Rate Design Initiative (RDI) that gathered insights from utilities and stakeholders on advanced forms of retail price signals to encourage a more dynamic environment aimed at reducing system costs (including GHG emissions), while also spurring beneficial electrification and potentially new business models and players.[7] The study that emerged from the RDI analyzed two types of innovative load shape management tools: rate design and direct load control via the utility or a third party. Recommendations include (1) recognizing the role that rates can play to manage future costs through price signals that can change consumer behavior; (2) implementation of improved rate designs may help overcome program enrollment challenges; (3) electric rates should target certain types of loads that are more responsive to price signals; (4) marketing plays an important role and should be supported; and (5) utilities and state regulators should look to new business/service models as technologies evolve that should allow and encourage participation of third parties in the market as partners to utilities and their customers. The Department will continue to build on the progress made through this initiative through its role as the state regulator and energy office.

Developing Renewable Supply

In 2017, Vermont began implementation of the Renewable Energy Standard (RES), the first such requirement in Vermont that electric utilities provide renewable energy to their customers. Prior to 2017, there were requirements for utilities to procure energy from renewable resources, but no requirement to retire the renewable attributes. The majority of these resources that predate the RES are still in the Vermont power supply mix and impact future resource procurements.

Renewable requirements have been used in Vermont to not only reduce the environmental impacts associated with electricity supply, but also as an economic development tool. For example, Tier 2 of the Renewable Energy Standard requires distributed renewable resources to be constructed within Vermont. This requirement has been a boon to solar developers in Vermont as these resources are the easiest to site, and the requirement coincides with net metering program. Given the interconnected nature of the New England grid, a new resource constructed elsewhere in the region and under contract to a Vermont utility would provide the same environmental benefits as a resource in Vermont, and likely at a lower cost.

As noted throughout this report, it is important to minimize pressure on electric rates, both from an equity standpoint (given the cost-based nature of electric rates) and considering the need to make heat pumps and electric vehicles as cost-effective as practical.

Impacts of COVID 19 Pandemic

The onset of the COVID-19 pandemic brought about widespread and immediate impacts on the energy sector in Vermont. Beginning in March, many of the state's utilities experienced reductions in total electric sales of around 5 to 10 percent, with some as high as 20 percent at times.[8] These reductions in total electric usage were primarily driven by steep reductions in electric energy use from customers in the commercial and industrial sectors that shut down, with some utilities experiencing reductions in sales as high as 30 to 60 percent. This reduction was moderated by an increase in residential energy use as people stayed at home complying with the Governor's Stay at Home order. Mobility within the state

[7] Information on the Rate Design Initiative is available at: https://publicservice.vermont.gov/content/rate-design-initiative#:~:text=The%20Vermont%20Department%20of%20Public,of%20Energy%20State%20Energy%20Program

[8] Data provided to the Department of Public Service by the electric distribution utilities.

dropped sharply in March and April 2020,[9] with an estimated 60 percent reduction in driving generally (to places such as work and retail shops) further resulting in reductions in energy used for transportation-related needs. Reduced demand for energy worldwide triggered a significant reduction in many fuel commodities prices, such as gasoline and heating fuel oil which each dipped below $2.00/gallon during the spring months.[10]

The impact on clean energy jobs within Vermont was clear, with a loss of 2,748 such jobs between March and May 2020 (the majority of which, 2029, were lost in April), representing more than 15 percent of the State's clean energy workforce (compared to a 20% reduction in jobs overall in Vermont).[11] Each of these impacts occurred in the context of much broader economic shifts, including large increases in the state's unemployment rate (which hit 16 percent in April[12]) and increases in customer utility arrearages. While such impacts have been experienced across income brackets, they have been felt most severely by Vermont's most vulnerable populations.

Transportation energy use was also affected, albeit unevenly across transportation modes. The shift to remote work for some Vermonters reduced daily commuting and associated energy consumption. Public transit ridership fell by as much as 70% in the weeks following the emergency of COVID-19 in Vermont; it has since only recovered slightly. Energy consumption from rail and road freight transport was much less affected. Walking and bicycling levels increased as Vermonters sought socially distanced outdoor activities.

While the immediate impacts were stark, the extent to which the pandemic will significantly affect Vermont's ability to meet goals outlined in the CEP ultimately depends on which of these immediate impacts persists into the long term. Initial evidence suggests some of these impacts have already started to subside. For example, as illustrated by the example in Figure 3, while many Vermont utilities initially experienced reductions in total electricity sales, which could contribute towards achieving the demand reduction targets identified in the CEP, recent data suggests electricity use has returned closer to 2019 levels with the reopening of most sectors of the state economy. Further, while distributed renewable energy deployments fell over the spring, new installations rebounded towards (and even exceeded in some months) levels seen in the past couple of years.

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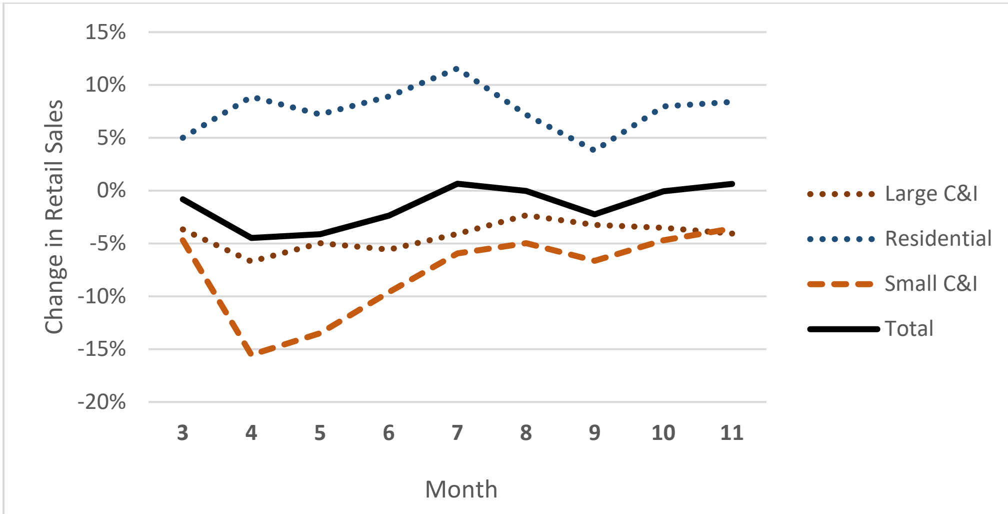
[9] *Oliver Wyman COVID-19 Pandemic Navigator – Transmission Rate comparison with changes in mobility and stringency.* Available at: https://pandemicnavigator.oliverwyman.com/mobility?mode=state&region=US_US-VT

[10] Department of Public Service Heating Fuel Survey, available at: https://publicservice.vermont.gov/content/retail-prices-heating-fuels

[11] BW Research for the CEDF and Department of Public Service. *2020 Vermont Clean Energy Industry Report.* Available at: https://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/CEDF/Reports/2020%20VCEIR%20Final.pdf. For context, over half (64%) the jobs lost (1299) since the beginning of the pandemic have been in the energy efficiency sector. BW Research Partnership, *Memorandum on Clean Energy Employment Initial Impacts from the COVID-19 Economic Crisis, October 2020*. https://www.bwresearch.com/covid/docs/BWResearch_CleanEnergyJobsCOVID-19Memo_Oct2020.pdf

[12] Vermont Department of Labor, *Economic & Labor Market Information.* Retrieved from: http://www.vtlmi.info/

Figure 3 - Percent Change in Weather Normalized GMP Retail Sales, 2020 v. 2019[13]



Longer term impacts of the pandemic, such as the extent of the economic recession on Vermonter's most impacted, and their effects on efforts to reach CEP goals ultimately remain uncertain. As the pandemic continues to unfold, the Department will continue to monitor the impact on areas such as energy use patterns related to less traveling, more activities done remotely (e.g., teleworking and telemedicine), the effects of depressed fossil fuels prices on incentives to transition to clean energy sources, and shifts in energy burdens (e.g., through increased unemployment or financial hardship for the most vulnerable at the same time residential utility bills increase due to greater time at home).

IV. Electricity

Overview

Vermont has had remarkable success in meeting the goals and requirements established for the electric sector. In 2010, Vermont utilities were required to retire renewable energy credits (RECs) for 55% of the kWh sales to customers; the utilities surpassed that requirement and provided sufficient RECs to meet 66% of sales. In addition, even though nuclear power is not considered renewable, it is considered to be carbon free for purposes of Vermont's GHG Inventory; for 2019, power from nuclear energy constituted 29% of the retail sales to customers.

In 2018, the electric sector contributed approximately 2% to Vermont's GHG emissions, compared to approximately 77% in the thermal and transportation sectors. The major challenge facing the electric sector is ensuring that renewable requirements are met in as cost-effective a manner as possible. This helps protect the economically vulnerable, who pay a greater share of income toward basic needs such as electricity. Lowering cost in the electric sector is also important to meet climate goals in the heating

[13] GMP represented roughly 76 percent of Vermont's total retail electric sales in 2019 based on the Department of Public Service's annual resource survey and is used here as an illustrative example. The trends in GMP's sales, with persistently increased residential sales generally offset by reductions in commercial and industrial sales, has been largely consistent across Vermont's utilities. Although, it should be noted that in the early months of the pandemic, some of Vermont's smaller municipality and cooperative utilities experienced more severe reductions in C&I sales, some in excess of 20 to 30 percent, and as much as 65 percent, below 2019 levels.

and transportation sectors – the cost of “fueling” electric vehicles and heat pumps is an important consideration for individuals in deciding whether to move to these technologies.

The 2016 CEP sets a goal of having 67% of electricity provided in the electric sector met through renewable generation by 2025. As the CEP makes clear, this goal is linked to the requirements of the Renewable Energy Standard and further states: “Power supply questions now revolve around the most cost-effective way to meet the RES requirements, not around how much renewable energy to acquire.”[14]

Demand Management

Demand management encompasses a range of service options that includes energy efficiency and load management strategies. Efficiency investments are those that can improve operations and/or perform work using less energy input than would otherwise be necessary. This section will discuss electric efficiency, but efficiency can and should be implemented across fuel types. Often, efficiency solutions can be implemented holistically. Thermal and transportation efficiency is discussed in those designated Sector sections.

Load management is generally associated with the shifting of load from less desirable to more desirable times. Traditionally, those have been focused on reducing peak during peak demand times, but more recently load management strategies have begun to be explored with the goal of also shifting load away from high energy cost and emission times, and/or to allow additional renewable generation to be interconnected to the grid. Innovative rate designs including demand response also fall under load management.

Energy Efficiency

Investments in energy efficiency continue to be critical to mitigating the increases in energy demand expected from the electrification of the thermal and transportation sectors. Indeed, electric efficiency remains Vermont’s first and best least cost-option to meet expected electric energy demand, saving Vermonters money on their electric bills while providing the state with significant economic and societal benefits. Vermont’s electric efficiency programs delivered by Efficiency Vermont and Burlington Electric Department, the State’s two electric Energy Efficiency Utilities (EEUs), have a long history of success in delivering these benefits to Vermonters, using a ratepayer-funded electric Energy Efficiency Charge (EEC) to expense investments that pay off over the long term. That success has limited the near-term, future potential for additional efficiency savings.

Since 2000, the EEUs have acquired significant electric efficiency resources that have met a significant portion of Vermont’s electric needs, at a lower cost than supply resources. Figure 4 shows Efficiency Vermont’s cumulative savings over time, while Figure 5 describes the results of BED’s efforts.

[14] 2016 CEP at 277.

Figure 4 - EVT's Electric Energy Efficiency Impacts[15]

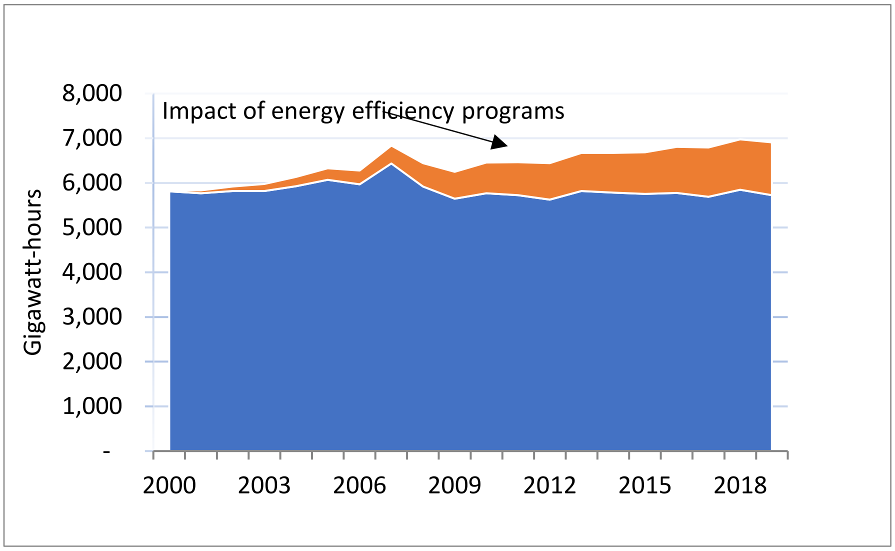
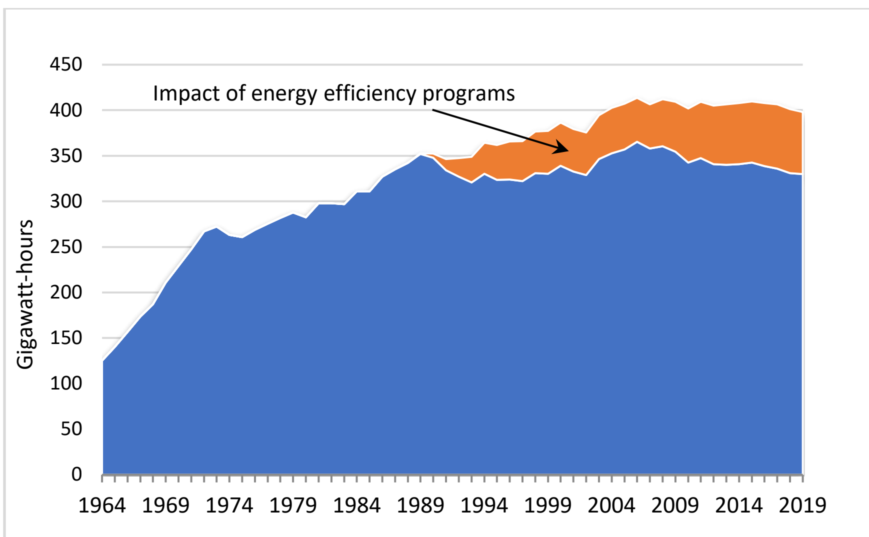


Figure 5 - BED's Electric Energy Efficiency Impacts[16]



In 2019, Efficiency Vermont secured 116,156 MWh and 19.6MW of resources, spending $43,499,740. BED acquired 3,854 MWh and 0.5 MW of resources, spending $2,626,876.

Every three years, as part of the Public Utility Commission Demand Resource Plan (DRP) proceeding, the Department of Public Service commissions an evaluation of the remaining electric efficiency potential in the state, to help inform the setting of appropriate budgets. While there still considerable potential to acquire efficiency savings over time, that potential is declining over time. Some of the future potential could be acquired sooner with greater incentives; however, it is important not to ramp up or down

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[15] Courtesy of Efficiency Vermont.

[16] Courtesy of City of Burlington Electric Department.

programs quickly, as that becomes problematic for the markets that the programs support and causes inefficiencies in program delivery – a stable path is generally preferred. Finally, it should be noted as electrification of the thermal sector continues, future opportunities for electric efficiency via weatherization may materialize.[17]

The DRP sets Quantifiable Performance Indicators (QPI) for each EEU; this structure sets out a framework of targets that effectively aims to balance priorities, encouraging the placement of efforts where they are provide value to ratepayers. Each EEU QPI framework also include a comprehensive suite of minimum performance requirements ensuring equity of EEU services across ratepayer incomes, service classes, geographic regions, and utility territories. In addition, each EEU Demand Resource Plan for 2021-2023 calls for the delivery of a coordinated set of efficiency programs and customer services. The EEU investments in energy efficiency approved in the DRP remain less costly than alternative investments that could be made to procure electric power and natural gas supply. In turn with energy efficient equipment in place, customer bills are significantly reduced the over the lifetime of the investments.

For Efficiency Vermont, the Commission Ordered a statewide electric energy efficiency budget of approximately $45,600,000 annually, down 8.8% from EVT's 2020 budget. This level of investment was structured, given declining loads and previous under collections, to keep constant the annual electric energy efficiency charge during the 2021-2023 performance period – a particular concern given the economic fallout from the ongoing pandemic. This level of investment will reduce the size of future power purchases, substantially mitigating increases in load and result in approximately 3,359,900 MWhs in reduced power purchases over the life of the projects (i.e., net lifetime MWhs). The three-year investment in electric energy efficiency is expected to result in 282,000 of annual MWh savings, 30,700 kW of peak summer savings, and 37,700 kW of peak winter savings. In addition, it will help reduce both local and regional infrastructure costs and help limit the need to upgrade the state's transmission and distribution infrastructure in some areas.

For the City of Burlington Electric Department, the electric energy efficiency budget is expected to be approximately $2,600,000 annually, down 13% from BED's 2020 budget. For BED, this level of investment is expected to acquire all reasonably available cost-effective potential, consistent with the program achievable potential described above. The three-year investment in electric energy efficiency is expected to result in 13,937 of first-year MWh savings, 1.8 kW of peak summer savings, and 2.1 kW of peak winter savings. In addition, it will help reduce both local and regional infrastructure costs.

[17] The overall decrease in Technical and Economic potential shown in Figures X and X over the analysis timeframe is driven by assumptions regarding reduced lighting potential over the first decade. An increase in potential in 2036 is associated with renewed savings opportunities from measures installed early in the analysis timeframe that have reached the end of their effective useful life.

Figure 6 - EVT and BED electric efficiency budgets[18]

	2021	**2022**	**2023**	Total
EVT Electric Efficiency Budgets	$45,583,399	$45,719,158	$45,769,989	$137,072,546
BED Electric Efficiency Budgets[19]	$2,661,737	$2,571,530	$2,631,882	$7,865,149
Total Electric Efficiency Budgets	$48,245,136	$48,290,688	$48,401,871	$144,937,695

Load Management

As traditional, passive energy efficiency potential declines, the potential (and need) for other forms of another form of demand management has increased. Vermont's and New England's grid has changed over the last several years, with significant amounts of distributed generation changing monthly and annual peak consumption days, patterns of consumption evolving as a result of technology adoption, and with the largest cost pressures generally occurring in winter months, during cold snaps when both heating and electric demands are the highest. Moreover, more "smart" technology, including communication, software, and integration tools have begun to become available.

The ability to flexibly manage load is critical to best recognize these changes to enable utilities to treat their loads – regardless of sector or size – as resources to respond to system needs on a very short-term, granular basis. This can, and should be, done in a manner that leverages incentives, direct controls, and rate design to deliver value for customers by shifting loads from less optimal times of the day to more optimal times of the day. These shifts could benefit the utilities in a number of ways.

Flexibly managing load is more complicated than traditional demand response, where a simple signal is sent to a customer and they are encouraged, by incentives to respond. Two-way communication adds the potential to, for example, "turn on" loads when needed, such as a sunny April day when loads are low and distributed generation is high, and electric circuits are running close to their capacity to handle the generation. In this way, flexibly managed load has the potential to avoid distribution upgrades, consume electricity when it is cheap, and increase the headroom of the grid to allow more renewable energy to be interconnected.

Vermont utilities have completed or are in the process of running several pilots to better understand and utilize load to minimize grid impacts. For example, Green Mountain Power, Washington Electric Coop, and Burlington Electric Department have all initiated pilots exploring various areas of load management capability – ranging from commercial customer opportunities to smaller sized loads associated with technologies such as heat pumps or electric vehicles. In addition, the Public Utility Commission recently approved Efficiency Vermont to avoid lost opportunities and foster load management by encouraging customers to participate (or be ready to participate) in load management programs, recognizing that when Efficiency Vermont is in a building discussing passive efficiency is an ideal time to also support load management systems.

[18] These numbers do not reflect DPS Evaluation and other costs.
[19] Efficiency Vermont's budgets have been approved by the Commission in case 19-3272-PET. BED's budgets are proposed, with no party to the proceeding objecting.

In 2019 the Department facilitated a Rate Design initiative, looking at both load control type measures considered above and general rate design. The study found that "the efficacy of [such programs] is largely a function of customer participation or enrollment, which is critical in the implementation process for innovative rates."[20] The study concluded with a series of recommendations intended to facilitate increased adoption of load control technologies to make effective use of the electric grid.

Renewable Supply

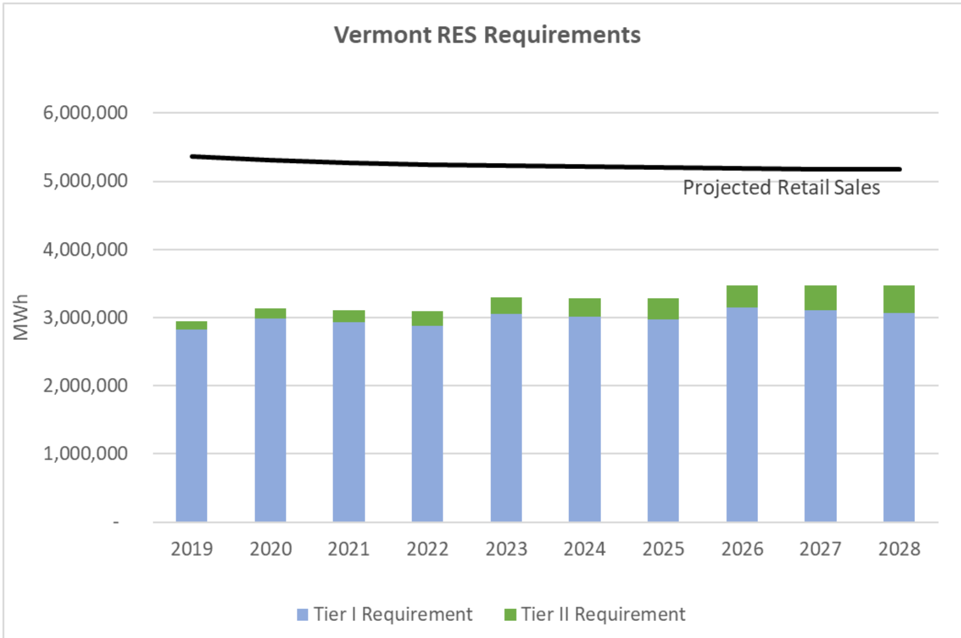
In 2017, the Renewable Energy Standard (RES) went into effect, requiring increasing percentages of Vermont's electric load to be met with renewable energy. The RES replaced the Sustainably Priced Energy Enterprise Development (SPEED) Program, that had required Vermont's electric utilities to enter into long-term stably priced contracts for renewable generation or build renewable generation, but did not require that Vermont's electric utilities retire the RECs associated with these facilities. Although the SPEED Program ended several years ago, the majority of resources procured under the program are still part of Vermont's energy mix.

For the electric sector, a utility demonstrates that it is supplying its electric customers with renewable energy through the retirement of RECs. Vermont's RES requires that Vermont's utilities retire sufficient number of RECs to cover an increasing percentage of retail sales. Tier I requires distribution utilities (DUs) to retire qualified RECs or attributes from any renewable resource capable of delivering energy into New England 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. Tier II requires DUs to retire qualified RECs equivalent to 1% of their annual retail sales starting in 2017, increasing by three-fifths of a percent each year, up to 10% in 2032. RECs associated with the net metering and standard offer programs are eligible for Tier II of RES. Appendix E of this report includes the Department's 2021 REPORT ON RENEWABLE ENERGY PROGRAMS, as required by 30 V.S.A. § 8005b, and contains additional data.

Tier I resources include any renewable generator in ISO New England (ISO-NE) and imports from neighboring control areas (e.g., Hydro Quebec, New York Power Authority hydro). Tier II of the RES is a carveout of Tier I and 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.

[20] Vermont Department of Public Service Advanced Rate Design Initiative, Final Report by NewGen Strategies & Solutions at 3 (August 2020). https://publicservice.vermont.gov/sites/dps/files/documents/Vermont%20PSD_Innovative%20Rate%20Design%20Study_08-12-20.pdf.

Figure 7 - Vermont RES Requirements



Of the 5,405,687 MWh that were sold in Vermont during 2019, approximately 66%, or 3,092,053 MWh, are renewable as demonstrated by the associated retired RECs produced by renewable generation facilities. An additional 27% of the MWhs sold were supplied by nuclear units; which are not renewable but are considered to be non-carbon emitting resources that help meet Vermont's GHG reduction goals.

Electricity Prices

There are three prices that are relevant to supplying electric energy to Vermont's electric customers: (1) the wholesale price represents the avoided cost of energy; (2) RECs represent the cost of meeting RES compliance; and (3) retail prices reflect the costs of power supply and other necessary utility services (such as transmission and capacity costs, explained below).

Wholesale Energy Prices

The average 2019 wholesale energy price in New England was $30.67/MWh ($0.03067/kWh); which is among the lowest prices since the introduction of the wholesale markets in 2003.[21] New England wholesale energy prices have been trending down as the price of natural gas has fallen. Natural-gas-fired units are typically the marginal units[22] in the region and therefore set the price – natural gas prices and wholesale energy prices correlate extremely well. Given constraints on the gas pipelines in the winter (due to natural gas being prioritized for heating in the winter) this means that annual average energy prices have become primarily dependent on winter temperatures. For example, the average wholesale energy price for the month of January 2019 was $56/MWh, while the price in October 2019 was $20/MWh. This seasonal variation impacts the relative value of different intermittent resources as

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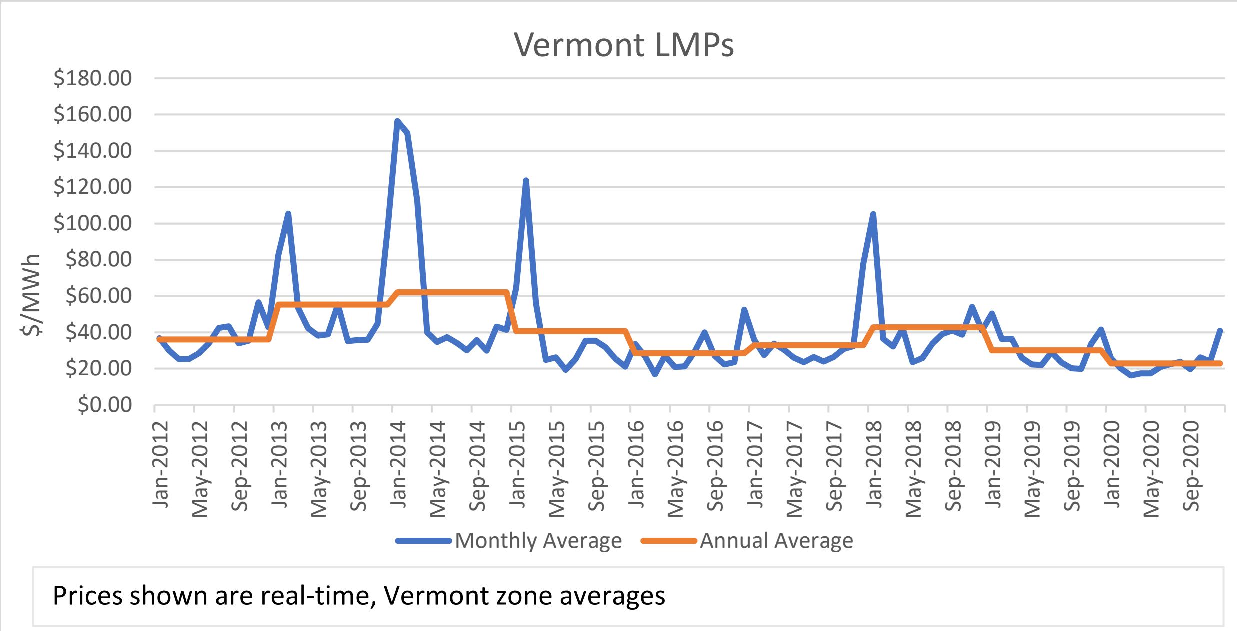
[21] ISO New England Pres Release, New England's Wholesale Electricity Prices Up in 2018. March, 2019. Available at: https://www.iso-ne.com/static-assets/documents/2019/03/20190312_pr_2018-price-release.pdf

[22] ISO-NE dispatches generation based on the price of the generation unit. A wind facility has not fuel costs and is therefore less expensive to dispatch than a natural gas-fired unit, which in turn in less expensive than an oil-fired resource. A marginal unit is the last resource needed to meet load in a particular period of time. Typically, as load increases, more expensive units are needed to provide power to the system, and this more expensive unit than becomes the marginal unit.

well, with resources that generally produce more energy in the winter having significantly more value than resources that produce in the spring and summer.

Figure 8: Wholesale Energy Prices for Vermont



The wholesale prices are indicative of what Vermont's utilities could be paying for power supply if they procured all energy needs through the ISO-NE market. However, there is statutory policy that Vermont utilities should pursue stably priced long-term contracts with renewable resources. Consistent with this policy, Vermont electric utilities are significantly hedged against wholesale market prices (either through long-term contracts or utility-owned generation resources),[23] and therefore the benefits of these current and historically low wholesale prices are muted for Vermont ratepayers. Conversely, Vermont ratepayers are not fully bearing the significant price increases that occur when cold weather drives up wholesale prices.

Wholesale prices also have an important role in the Department's and Commission's review of additions to an electric utility's power supply portfolio as well. The cost of any new resource is compared against wholesale market prices – to the extent that there are significantly lower wholesale prices, it becomes more difficult for a utility to demonstrate that a particular resource provides an economic benefit to Vermonters. A similar approach is also applied to energy efficiency – low wholesale energy costs means that there are likely to be less energy efficiency measures that are economically justifiable.

Renewable Energy Credit Prices

RECs represent the renewable attributes of energy. REC prices can vary considerably over time and are largely driven by state renewable energy requirements within the region. In order to understand Vermont REC price forecasts, it is important to first understand the relationships among the different regional REC markets. Vermont Tier I RECs are generally equivalent to Class II or existing resource, RECs in neighboring states, with the exception that imports from HydroQuebec (HQ) and New York Power Supply Authority (NYPA) are considered renewable in Vermont but not in other states. It follows that Vermont Tier I prices tend to be very similar to Class II prices in neighboring states. Currently, Tier I

[23] Vermont's renewable energy policy encourages Vermont utilities "to enter into affordable, long-term, stably priced renewable energy contracts that mitigate market price fluctuations for Vermonters." 30 V.S.A. § 8001(a)(3).

prices are low given the relatively low demand in the region for these RECs and the ability of Vermont utilities to use HQ and NYPA attributes to satisfy the Tier I requirement. However, other states have recently shown an interest in expanding their requirements related to existing renewable resources, which would drive up Tier I prices.

Vermont Tier II resources are a small subset of Class I or premium resources in other states, so when there is sufficient Tier II supply in Vermont, excess RECs will be sold as Class I to neighboring states, which results in Tier II prices that are very similar to Class I prices. However, if a shortage of Vermont Tier II resources develops, for example, resulting from constraints on the electric distribution system, then prices will diverge with Tier II prices approaching the Alternative Compliance Payment[24] while Class I prices trade at a different market price.

Tier I RECs are generally satisfied with RECs from existing, utility-owned resources or purchases of unbundled RECs from existing renewable resources physically located in New England or imported into the region. Tier II RECs are generally satisfied with RECs from utility-owned resources as well as resources from Vermont's net metering and standard offer programs. Vermont statute requires electric utilities to retire RECs from net metered systems; these RECs can be counted toward Tier II of RES. However, the compensation currently paid to net metering systems significantly exceeds the wholesale energy price and REC prices combined, and therefore results in a higher cost of compliance for meeting the RES and serving Vermont customers with electricity than would alternative resources.

Retail Prices

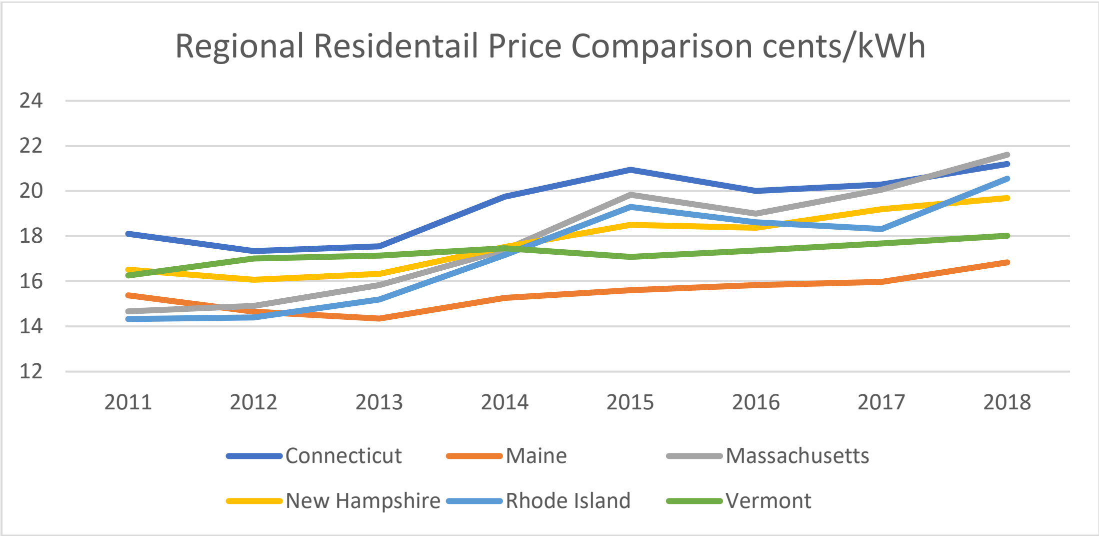
Retail rates are what are paid by end-use customers. These rates reflect not just the power supply portfolio but also other regional costs to secure and deliver wholesale electricity (e.g. ISO-NE capacity and transmission), the costs of maintaining the distribution system (e.g. tree trimming, upgrading lines and transformers, etc.), and administrative costs (e.g. billing, customer service, etc.). The power supply component, along with regional capacity and transmission costs, generally accounts for 50-60% of retail rates.

Vermont's retail prices tend to be relatively stable compared to retail prices in other states. This is due in part to the fact that Vermont remains the only state in the Northeast with vertically integrated electric utilities[25] and also due to the statutory policy regarding stably priced contracts and the resulting hedging strategy employed by Vermont's utilities. The retail rates of Vermont's utilities vary considerably, and are dependent on a number of factors, including power supply commitments and whether the utility's service territory is urban or rural. The figure below provides a comparison of electric prices among the New England states.

[24] The Alternative Compliance Payment acts as an upper bound on the price that a DU must pay to comply with RES. If REC prices are higher than the ACP, the utility may pay the ACP instead of retiring a REC.

[25] A vertically integrated utility is able to own generation resources or enter into long-term contracts with merchant generators. In other states, absent specific statutory mandates to the contrary, regulated utilities are not able to own generation or enter into contracts for periods of longer than five years.

Figure 9: Residential Electric Price Comparison[26]



Recommended Policies

In order to meet the 90% renewable by 2050 goal in the 2016 CEP, and also achieve GHG reductions mandated by the Global Warming Solutions Act, there must be substantial changes in the thermal and transportation sectors that contribute the vast majority of GHG emissions in Vermont. The most promising pathway is electrification of these sectors through increased usage of electric vehicles and heat pumps.

Vermont's RES provides a framework for electric utilities to procure renewable energy for their customers, and utilities are exceeding these requirements. However, additional requirements such as the current net metering program are causing the RES requirements to be met at a cost higher than necessary. The Commission has reduced net metering compensation during their past two biennial rate adjustment proceedings and has indicated that developers should expect the compensation to continue to decline to be consist with the value of the resource. The Department continues to support this move to lower compensation for excess generation from the net metering program. See Appendix E – Report on Net Metering Program, for additional details.

[26] Source: Energy Information Agency.

V. Thermal Energy

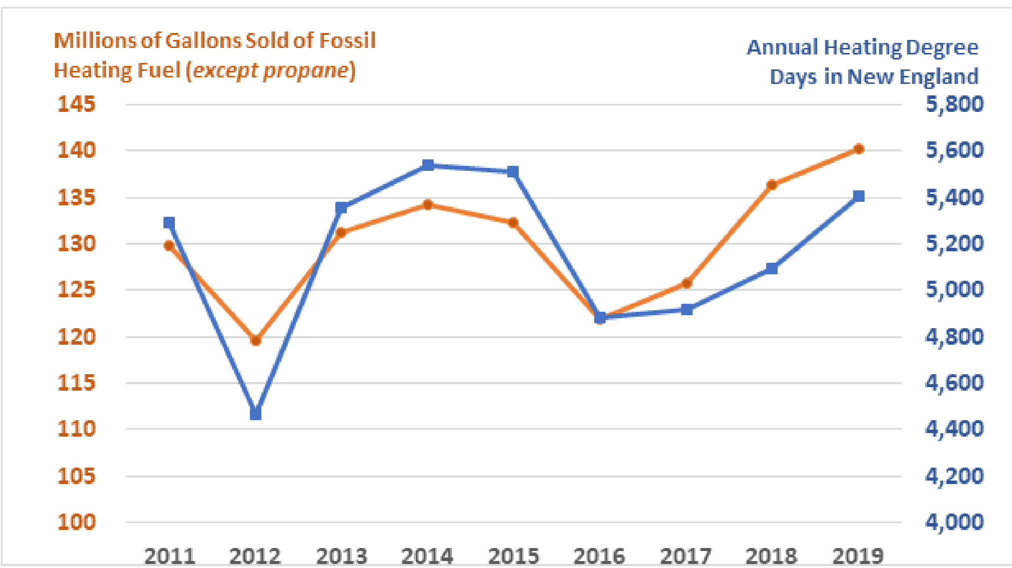
Overview

The thermal energy sector encompasses the energy required to heat and cool Vermont's buildings, provide domestic hot water, and support certain industrial processes. While typically focused on heating needs, this sector has also begun to provide for thermal cooling needs as summer trends towards warmer weather and deployment of electric heat pumps increases the amount of air conditioning used in Vermont homes and buildings.

Based on most recent available data from the Vermont Department of Environmental Conservation,[27] residential, commercial, and industrial sector fuel use accounted for 27.5 percent of the state's greenhouse gas emissions and approximately 47 percent of the state's total energy use.

The energy required to meet thermal needs can vary widely depending on the weather in any given year, with the increased usage during particularly cold winters (or increasingly, warm summers) and more moderate demand during mild winters. Figure 10 illustrates the correlation between heating degree days and heating fuel sales each year, with the years with the highest number of heating degree days also exhibiting higher volumes of fossil fuel sales. Trends in recent years are also beginning to show increasing numbers of cooling degree days suggesting the state may begin to see similar trends in thermal cooling demands as well.

Figure 10 - Correlation of Heating Degree Days and Heating Fuel Sales by year



Comprehensive Energy Plan Goals

The 2016 Comprehensive Energy Plan (CEP) outlines numerous goals specifically focused on thermal energy use. In particular, the CEP sets goals of supplying 30 percent of the heat for buildings and 25 percent of thermal needs for industry with renewable energy sources by 2025. In addition, the CEP calls

[27] Department of Environmental Conservation *Vermont Greenhouse Gas Emissions Inventory and Forecast: Brief 1990-2016*. Retrieved from: [https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_and_Forecast_1990-2016.pdf.](https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_and_Forecast_1990-2016.pdf)

for increasing the use of bioenergy and heat pumps and 10 V.S.A § 581 sets the goal of weatherizing 80,000 homes by 2020. With 27 percent of thermal needs currently met with renewable supply, the state is making reasonable progress towards meeting the renewable energy CEP goals while the state will not meet its target to weatherize 80,000 homes by the end of 2020.

This chapter of the Annual Energy Report reviews progress towards these goals in more detail, discussing ongoing efforts to reduce demand for thermal energy and increase the amount of the state's remaining thermal needs being met by renewable supply. Each of the following sections discusses recent activity in Vermont aimed at achieving these goals as well as major changes to relevant markets, technologies and costs that might impact progress towards meeting CEP goals. Finally, the chapter offers policy recommendations for future actions that might support achievement of the CEP goals.

Reductions in Demand

Efficiency investments significantly reduce the need for renewable thermal fuel supply and reduce costs for Vermonters. In addition to goals regarding the source of energy used to meet the state's thermal needs, the CEP recognizes this opportunity and sets out goals to reduce total energy consumption in the state. In particular, the CEP sets the goal of reducing total energy consumption per capita 15% by 2025, and by more than one third by 2050.

Investments in thermal demand reductions through weatherization programs are good for Vermont's economy. The Public Service Department and the Agency of Commerce and Community Development summarized the broad economic impact to the Vermont economy of the State's core weatherization efforts. The Agencies estimate that over the period from 2020-2030, the sustained investments in low-income and market rate programs increase personal income $27 to $39 million per year, increase GDP $20 to $21 million per year, and employ 390 to 440 people throughout the analysis period.[28]

Currently, several initiatives seek to help achieve these goals and advance progress towards weatherizing Vermont's buildings and setting efficient appliance standards and building energy codes. The following sections discuss recent activities in each of these areas.

Fuel Efficiency Programs

Vermont's housing stock is composed of a large proportion of older buildings that require more energy to heat than weatherized and newer buildings. Weatherization programs focus on improvements to building insulation and air sealing to reduce the energy required to heat and cool indoor spaces, the cost to the homeowner, and the carbon emissions from burning of fossil fuels for space heat. Most weatherization programs also offer incentives to retrofit heating and ventilation equipment to further reduce energy costs and improve indoor air quality. 10 V.S.A § 581 also sets residential building energy efficiency goals including the goal to weatherize 80,000 homes by 2020.

There are five major weatherization programs in Vermont that are contributing to meeting the building energy goals of the state: Efficiency Vermont's Home Performance with ENERGY STAR program, Vermont Gas Systems' Home Retrofit program, the City of Burlington Electric Department, the Weatherization Assistance Program of the Office of Economic Opportunity (OEO), and 3E Thermal. These programs are discussed in greater detail in Appendix A of this report.

[28] The Agencies' summary was originally filed in Public Utility Commission Case 19-2956, the Commission's investigation pursuant to Act 62 of 2019 on the best way to deliver holistic efficiency services to Vermonters.

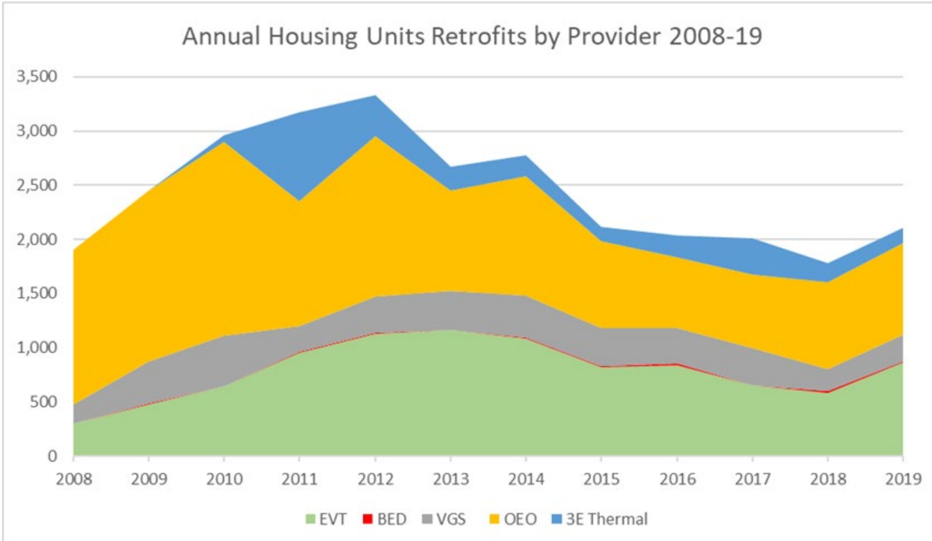
The five weatherization organizations' 2019 accomplishments are summarized in Figure 11, below. The average fuel usage reduction is 22% for the 2,103 comprehensive energy retrofit projects completed in 2019, resulting in carbon emissions reductions of approximately 3,122 tons.

Figure 11 - 2019 Weatherization Accomplishments

Total Projects (# units served)	**2,103**	The total number of housing units counted toward the annual goal include all comprehensive projects completed through the five participating organizations (EVT, VGS, BED, OEO and 3E Thermal).
Average % Fuel Usage Reduction	**22%**	The average fuel usage reduction for projects completed. Does not include projects that span multiple years. Fuel use reductions are measured using actual fuel usage data when available and reasonable estimates when fuel usage data is unavailable.
Annual Carbon Emissions Reduction (tons)	**3,122**	Carbon reductions use a uniform calculation method based on Federal standards published on the EIA website for fossil fuels, and Department of Public Service values for electricity savings.
Incentive Costs	**$13,322,816**	Direct financial incentives to the homeowner or building owner
Participant Costs	**$7,577,620**	Participant contributions to the cost of building improvements
Total Project Costs	**$20,900,436**	

Figure 12 provides a historical view of the number of housing units that have been weatherized over the last decade in Vermont by program administrator.

Figure 12 - Progress towards meeting 30 V.S.A. § 581(1) Statewide Thermal Efficiency Goals



Vermont will not reach the targets articulated in 10 V.S.A. §581. New and innovative policy structures must be considered. The Public Utility Commission, pursuant to Act 62 of 2019, has undertaken a process to evaluate the gaps in service delivery in Vermont, and propose solutions. Its report is due concurrent with this Annual Energy Report. The process, which included input from a broad array of stakeholders, made clear that new and innovative approaches to weatherization delivery are necessary, both to secure additional funding and to deliver successful programs at a lower cost, extending limited public dollars. Act 62 of 2019 also allocated some electric efficiency charge funds to supplement weatherization investments. The Commission's interim report, following input from stakeholders, concluded that electric ratepayers should not pay for weatherization investments (unless the weatherization was in an electrically heated home) long term. One reason was that electric costs must stay reasonable to encourage customers to transition their thermal and transportation energy usage to be powered by electricity.

Natural Gas Energy Efficiency

Vermont Gas Systems, Inc. (VGS) is an appointed Energy Efficiency Utility, providing efficiency services within its service territory. Whereas the electric EEUs in Vermont have offered electric energy efficiency programs for several years, natural gas energy efficiency offers more future savings opportunities due to the relatively smaller historic investments and continued greater opportunity for cost-effective thermal shell savings. In the residential sector, annual increases in potential savings are mitigated by rates of natural gas service territory expansion, and the increased prevalence of cold-climate heat pumps in the VGS service area.

Natural gas efficiency investments throughout the 2021-2023 performance period will acquire energy and peak day resources at a lower lifetime price to ratepayers than most supply alternatives. The VGS territory energy efficiency budget increases from $3.6 million in 2020 to $4.6 million, $5.3 million, and $5.8 million in 2021-23, respectively.[29] This level of investment is consistent with available potential and a reasonable program ramp rate. This increased investment will not proportionally increase the efficiency charge, however, as the Commission approved a strategy for VGS to invest its own capital in efficiency, in exchange for a return over time – a payment structure that more closely matches savings

[29] See, Case No. 19-3272-PET.

with cost. This structure is another example of innovation and responsiveness in regulatory policy, allowing for greater investment sooner without undue short-term burden on ratepayers.

If VGS achieves its savings targets, the 2021-2023 total budgets of approximately $15.6 million will result in more than $41 million in lifetime natural gas savings from 239,560 of incremental annual Mcf savings and 1,356 Mcf of peak day savings and will reduce annual greenhouse gas emissions by more than 13,000 metric tons.

Building Energy Standards

Vermont has both residential (RBES) and commercial (CBES) building energy standards, which set minimum efficiency requirements for new and renovated buildings. Building Energy Standards serve to avoid lost efficiency opportunities in long-lived infrastructure, using best-available established technology. They are appropriately applied when cost-effective on a lifecycle basis, locking-in savings for consumers.

Throughout 2018 and 2019, the Department undertook an extensive public stakeholder engagement process to update Vermont's Building Energy Standards from the 2015 version. Updated standards are designed to provide more reductions in energy use and emissions over the life of a building when compared with a similar building constructed prior to the standards going into effect. The new standards were adopted through the state rulemaking process in December 2019 and took effect on September 1, 2020.[30]

The Department is required to estimate the cost of complying with the new energy codes as part of the rulemaking process. The cost of building an average Vermont home will increase with the new requirements in the 2020 RBES, although the resulting energy savings will pay for those increased construction costs within ten years. Complying with the new RBES will increase costs by almost $5,000 but will save over $500 per year in energy costs, for a simple payback of less than 10 years. Compliance evaluations have been completed to determine the percent of building projects that met the technical requirements of the energy standards. During the 2015 and 2016 period, compliance with the residential code was reported to be 66% and for commercial projects compliance was reported to be 90%.[31]

Appliance Standards

Appliance efficiency standards are a highly cost-effective policy to reduce energy and water costs for Vermonters by setting minimum efficiency standards for household and commercial appliances and equipment. These standards lock-in savings for customers by requiring that the minimum product available is more efficient. Generally, appliance standards are thought of as the domain of the federal government because of broad applicability across states. However, the Vermont Legislature has now passed two bills that establish appliance and equipment efficiency standards for products sold or installed in Vermont. Act 42 of 2017 adopted the federal efficiency standards in effect on January 19,

[30] The new standards can be found on the Public Service Department's website at https://publicservice.vermont.gov/content/building-energy-standards.

[31] The Residential New Construction report, which contains the RBES compliance information, is available at: https://publicservice.vermont.gov/sites/dps/files/documents/VT%20SFNC%20Overall%20Report.pdf. The 2016 Vermont Business Sector Market Characterization and Assessment Study, which contains the CBES compliance information, is available at: https://publicservice.vermont.gov/sites/dps/files/documents/2016%20VT%20Commercial%20Market%20Assessment%20Report_0.pdf.

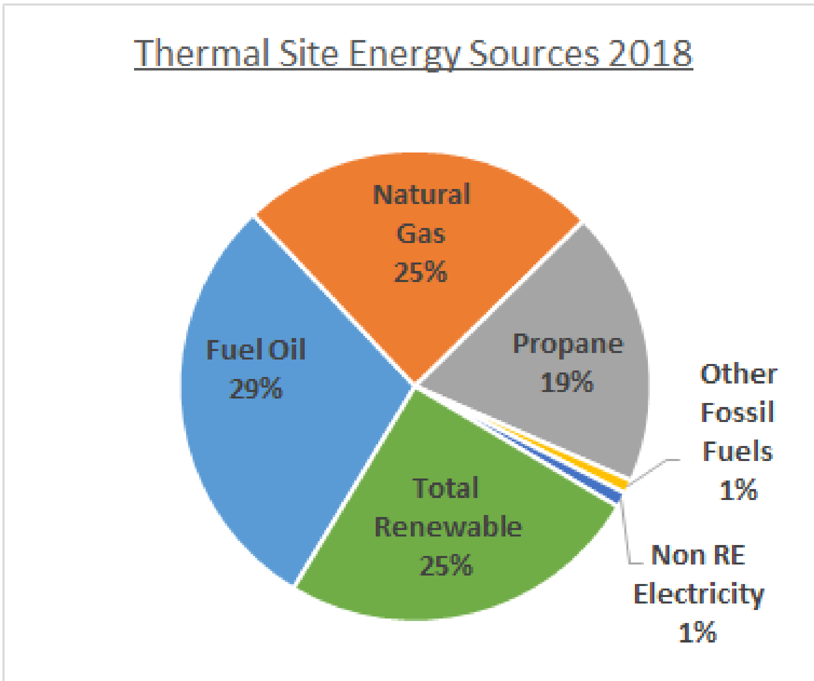
2017 for several products so that the same standards will be in place in Vermont should the federal standards be repealed or voided.

Supply

As discussed in the introduction, the CEP lays out goals to provide 30 percent of the thermal needs of buildings with renewable energy by 2025.

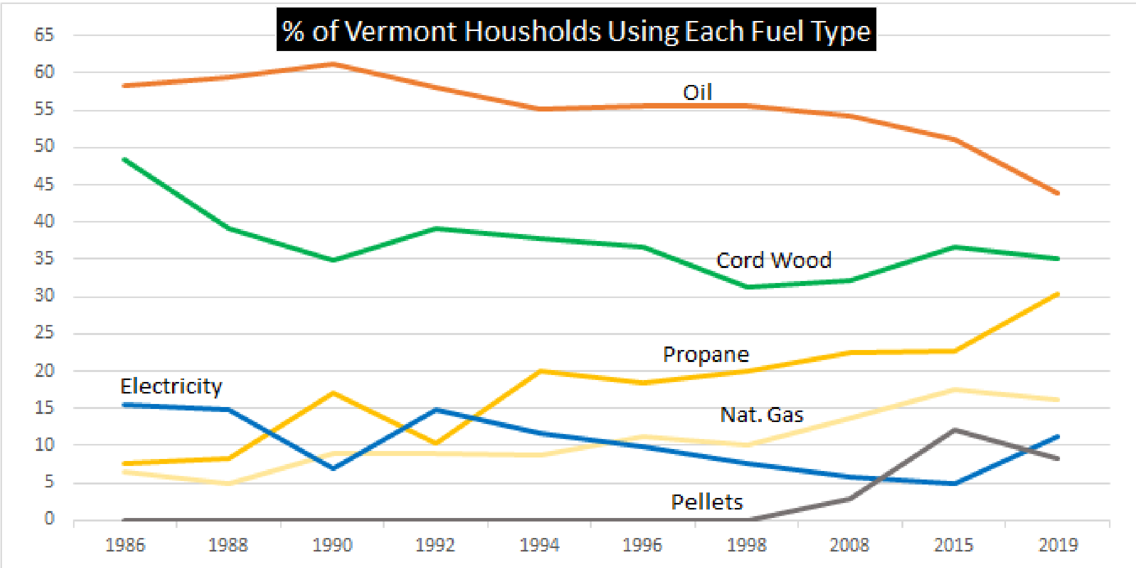
In 2018 Vermont consumed 57,529 billion BTU (BBTU) (or 16,860 MWh) of energy to meet thermal needs. Of this, 25 percent came from renewable energy sources, 29 percent from fuel oil, 19 percent from propane, and 25 percent from natural gas. The remaining demand was supplied by non-renewable electricity (one percent)[32] and other fossil fuels (one percent).

Figure 13 - Heating fuel source – total thermal site energy[33]



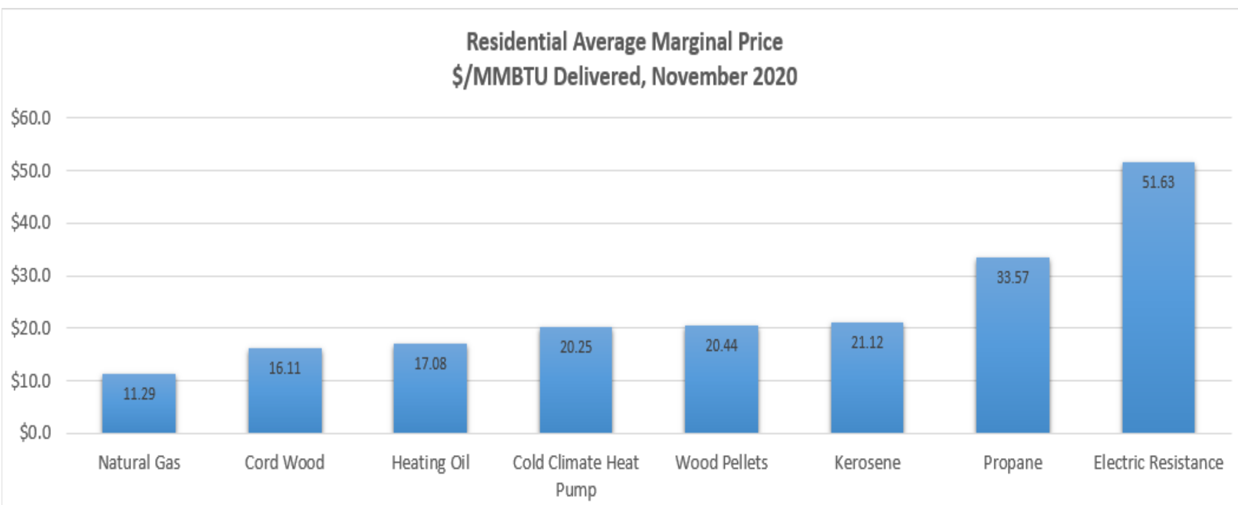
[32] As explained in detail further below, electric heating can be considered renewable only to the extent that the power supply characteristics of the host utility is renewable.
[33] Based on 2018 EIA fuel (site energy) data (as of Nov. 2020) updated with data compiled by the VT Energy Action Network and combined with data from PSD for electrical system mix and electricity usage, and ANR 2019 survey data on wood heating fuel use and types of home heating equipment used.

Figure 14 - Percent of Vermont Households Using Different Fuel Types[34]



As illustrated in Figure 14, natural gas and many renewable energy resources are less expensive than or at least cost competitive with petroleum products on a dollar per MMBTU delivered basis; however, in addition to ongoing fuel costs, up-front investments in heating systems can be a considerable barrier to switching to renewable fuels.

Figure 15 - Residential Average Marginal Price per MMBtu Delivered by Heating Technology



This section reviews the various sources of thermal energy supply, first discussing efforts to increase the percentage of thermal need met by renewable sources, then considering electric thermal energy (enabled by technologies like heat pumps and baseboard heat), and finally touching on non-renewable thermal energy from fossil fuels. It should be noted that electricity provides both renewable and non-renewable sources of thermal energy depending on the mix of fuels used to generate the electricity. In Vermont, the electric supply is on average 66 percent renewable, although this varies by utility service

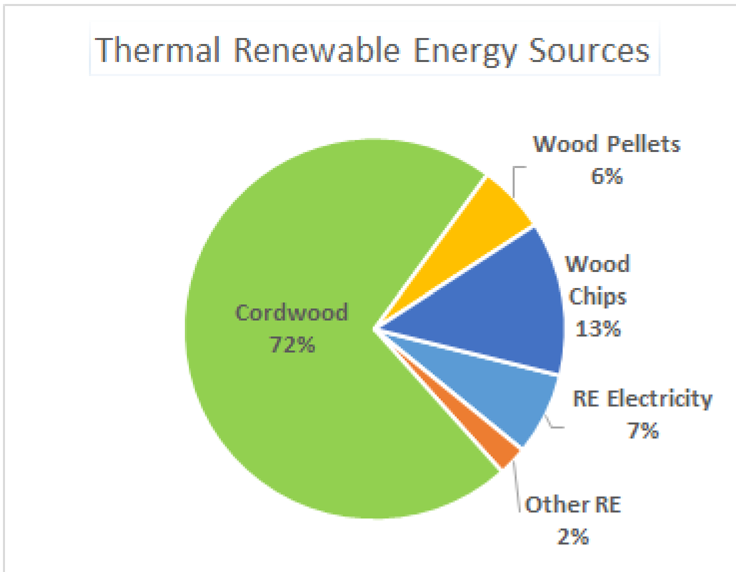
[34] Data from the Dept. of Forests, Parks, and Recreation's Fuel Use Reports, 1995-96 to 2018-19 heating seasons. Note: This is the percent of households that reported using each one of these heating sources, and each household could report using more than one fuel source. As a result, the sum of the lines at any given point is not 100%.

territory with some utilities providing 100 percent renewably generated electricity. Thus, discussing electricity as a supply source involves considering both the fuel sources generating the electricity and the technologies that enable electricity to provide thermal services.

Renewable

In Vermont, the dominant source of renewable thermal energy is wood (biomass), typically in the form of cordwood, wood pellets, and/or wood chips. As illustrated in Figure 16**,** renewable thermal energy was supplied primarily by cordwood (72 percent), followed by 13 and 6 percent from wood chips and pellets, respectively. This is roughly consistent with the previous two years.

Figure 16 - Breakdown of thermal renewable energy sources[35]



Additional renewable thermal supply is provided by biofuels, renewable natural gas, and renewable electricity. The following sections provide information on recent activity around wood, biofuels, and renewable natural gas (electricity, generally, is addressed in the next section).

Wood

Expanded use of advanced wood heating systems will help Vermont make measurable progress toward several energy goals. The use of wood for heating is a component of achieving Vermont's long-term goal of meeting 90% of its total energy needs from renewables. Approximately 22% of Vermont's space heating needs are being met with some type of wood heating.

Cordwood

Cordwood burned in wood stoves is by far the most common type of wood heating in Vermont. Just over a third (35%) of Vermont households reported using cordwood as a primary or secondary heating source during the 2018-2019 heating season.[36] While the percentage of households using cordwood for

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[35] Based on 2018 EIA fuel (site energy) data (as of Nov. 2020) updated with data compiled by the VT Energy Action Network and combined with data from PSD for electrical system mix and electricity usage, and ANR 2019 survey data on wood heating fuel use and types of home heating equipment used.

[36] Vermont Residential Fuel Assessment for the 2018-2019 Heating Season. VT Department of Forests, Parks and Recreation.

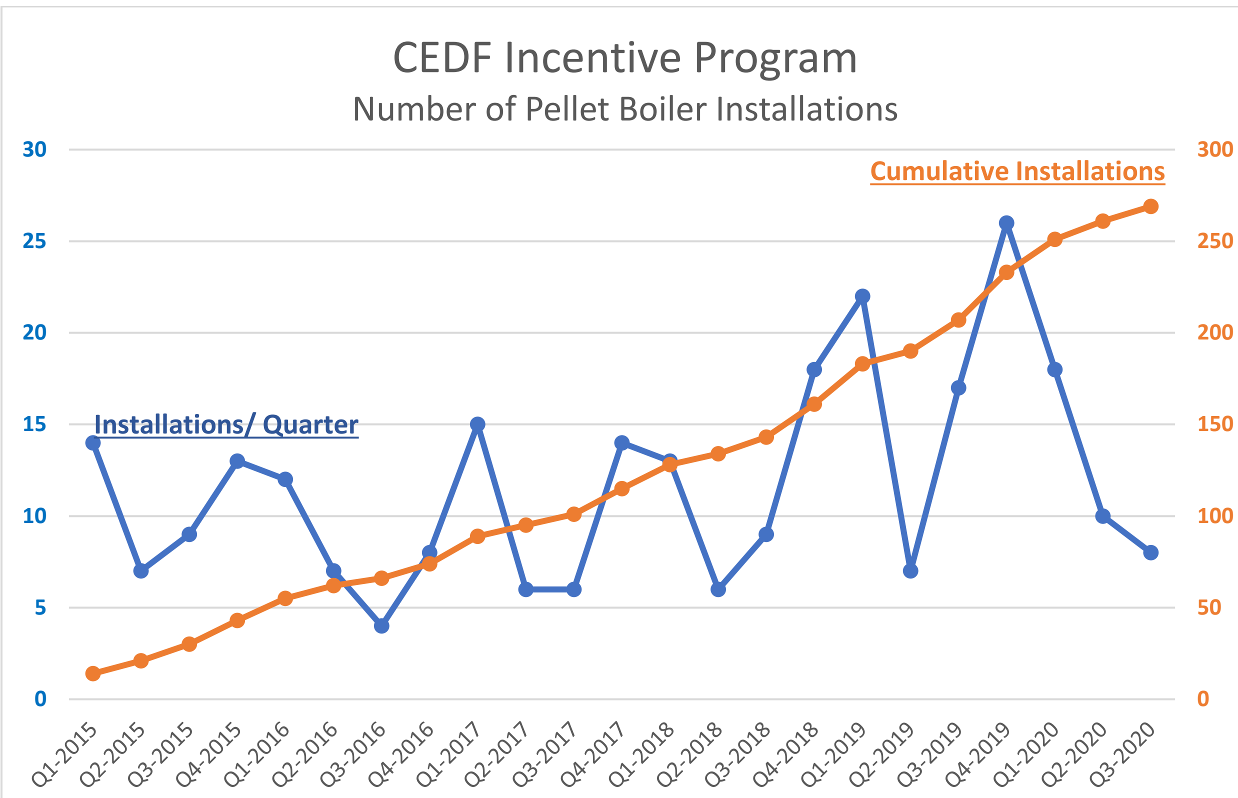
heat has decreased as compared to the 1980s, it has increased by nearly four percentage points since 1998.[37]

Nearly two-thirds of Vermont households using cordwood rely on it as their primary source of heat and just over one-third use it for supplemental heat. The number of households using cordwood as their primary source of heat has remained steady since the 1990s and remains far lower than reported usage in the 1980s.[38]

Pellets

Increasingly Vermonters use wood pellets to heat their homes and businesses. Over the last five years the State has promoted advanced wood heating, with a focus on pellets. Advanced wood heating (AWH) is defined as a space heating system that meets the following conditions: 1) utilizes highly efficient combustion technology, 2) produces low levels of emissions, 3) supports healthy forest ecosystems, and 4) consumes local wood. For Vermont to meet its thermal goals it is important that AWH program designs incorporate all four of these conditions. Through the Clean Energy Development Fund and Efficiency Vermont's incentive programs there has been an increase of at least 269 new pellet boiler systems installed in Vermont over the past five years (figure 17).[9]

Figure 17 - Number of Pellet Boiler Installations in the CEDF Incentive Program



In addition to the pellet boilers, there has been an increase in the number of pellet wood stoves, in part due to incentives from distribution utility Tier 3 programs.

[37] *Id.*

[38] *Id.*

Wood Chips

While there are many chip systems in schools and state buildings, many of them are reaching the end of their life and very few systems have been installed recently. One of the difficulties of chip systems is the large indoor/heated space required so that chips do not freeze. These large concrete bunkers or other structures add sizeable cost in dollars and space requirements to a project. Recent developments have been made to sell dry chips that will not freeze in the winter but are also screened to ensure a uniform smaller size. This allows the chips to be delivered in trucks and blown into an outdoor silo. This lowers the cost of the project but adds to the cost of the chips, although dry chips, with their lower moisture content, do burn more efficiently and have lower emissions.

Major Changes in the Wood Heat Markets, Technologies, and Costs

The extended drop in fossil fuel prices over the last five-six years has been a key factor in limiting the success in expanding Vermont's wood heat market. While cord wood and bulk wood chips remains cost competitive on a $/MMBtu basis, residential customers are not receiving the same savings by switching to pellets and the savings achievable by switching to chips is small compared to the cost of heat system conversions. Thus, older fossil fuel systems are kept until the project economics improve though fuel savings. The State provides incentives that typically cover about 12 percent of the total system costs. While these incentives help improve the economics for some systems, they are often not high enough to overcome high upfront capital costs for systems.

Average system costs for a residential pellet boiler have remained just above $20,000 since the State started tracking costs as part of its incentive program that began in 2015. The State has not seen the economies of scale—even with similar promotional efforts of other New England states—needed to reduce equipment costs. Most of the pellet boilers and furnaces used in the state are imported from Europe, as that is where the technology is most advanced and able to meet the efficiency and pollution emissions requirements.

Improvements in wood heating technologies have greatly decreased the level of emissions from wood heating, specifically particulates. The discussion regarding carbon emissions from wood has been evolving and is something the Public Service Department and the Division of Climate and Air Quality within the Department of Environmental Conservation continue to discuss and work on together.

Since most particulate pollution from wood stoves comes from old wood stoves, the CEDF/PSD have worked with ANR, Efficiency Vermont, and grantees on wood stove change-out programs. These programs have been designed to improve the air quality by reducing particulate emissions, as well as to support the use of a local wood as a renewable fuel. The amount of change-out slowed in 2020 as the CEDF ended its wood stove change-out program at the beginning of the year and EVT reduced aspects of its incentives at the same time.

Renewable Natural Gas

Renewable natural gas (RNG), also referred to as bio-methane, is a type of biofuel produced by anaerobic digestion of organic waste such as landfills, farm and food waste, or wastewater sludge. As methane is 28 times more potent as a GHG than carbon dioxide, processing it for use as a heating fuel has the dual benefits of destroying the methane and offsetting the use of fossil fuels. RNG is currently playing a relatively small role in the heating sector, although it is expected to increase over time.

VGS established a program in 2017 to offer its customers the option to purchase RNG as a portion of their natural gas usage. Customers who choose to purchase a portion of their gas usage as RNG are charged an additional amount per ccf (hundred cubic feet) used based on the percentage RNG they wish to purchase. VGS currently purchases RNG from suppliers in Quebec and Iowa. As of late 2020, VGS has roughly 100 customers enrolled in the RNG program. Two other RNG suppliers in Salisbury, Vermont and London, Ontario are scheduled to go online in 2021. The Salisbury project will be connected to the VGS distribution pipeline and will supply nearby Middlebury College with 100% RNG. The digester is expected to produce enough excess capacity to also supply around 400 homes. Since it is impossible to physically supply a specified percentage of RNG to individual customers, VGS customers in essence are purchasing RNG "attributes," similar to how electric utility customers purchase electricity under renewable energy riders.

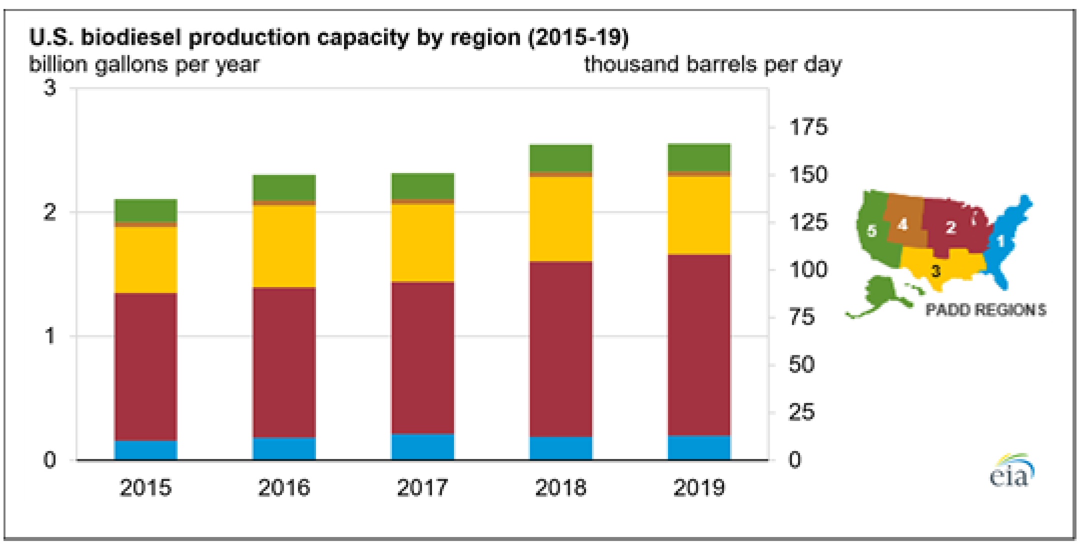
In November of 2019 VGS announced plans to increase its levels of RNG so that 20% of its supply mix for retail customers will come from RNG by 2030.[11] Vermont Gas projects that over the first five years of the program their customers could potentially consume over 500,000 Mcf (thousand cubic feet) of RNG, although it is difficult to predict participation in a voluntary program that requires customers to pay a premium price. VGS customers purchased about 12,000 Mcf of RNG in 2019 and are projected to purchase 25,000 Mcf in 2020. RNG is significantly more expensive than natural gas, with RNG price estimates of $12/Mcf to $25/Mcf, compared to $3/Mcf.

Biofuels

Biofuel resources are produced directly or indirectly from organic matter. Liquid biofuels include biodiesel and ethanol, both of which are used in transportation (and covered in that section). Biodiesel is also blended with ultra-low sulfur heating oil and sold as branded "BioHeat®."

Biodiesel is the renewable fuel added with petroleum diesel in distillate heating oil. There is no commercial scale production of biodiesel in Vermont, and only modest amounts produced in the northeastern region of the U.S. National data for 2018 show that New England yielded about 43 million gallons of biodiesel as part of the overall eastern production of about 197 million gallons. Nation-wide, production for the same period came in at about 2.5 billion gallons per year (Figure 18).[39]

Figure 18 - National Biodiesel Production[40]

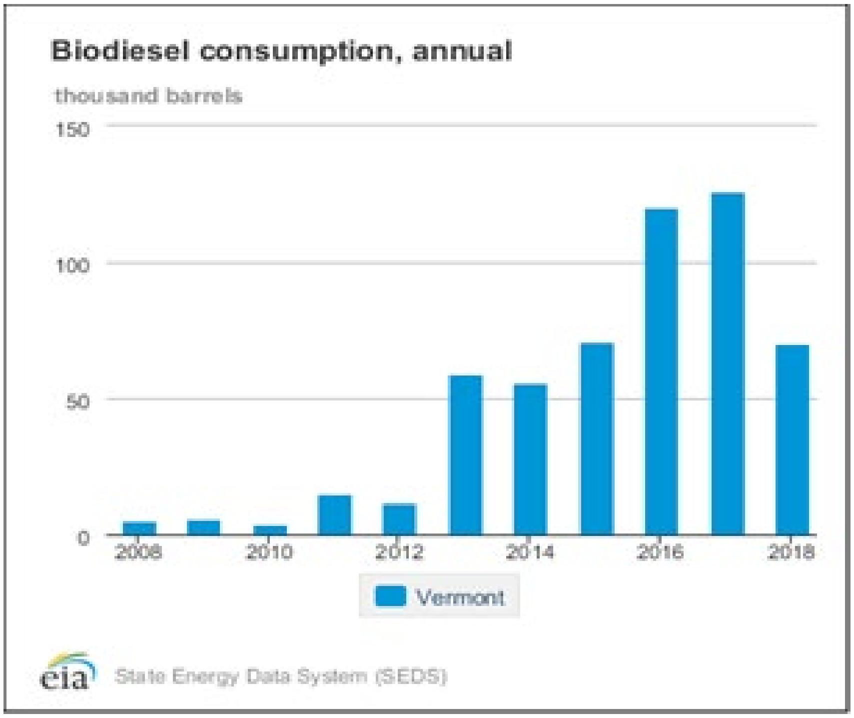


[39] US Biodiesel Annual Production. Energy Information Administration. January 2019. www.eia.gov/biofuels/biodiesel/capacity/.

[40] Source: Energy Information Administration.

Estimated production for New England stood at 46 million gallons per year as of July 2020.[41] Consumption of all biodiesel (heating and transportation) in Vermont was approximately 2.9 million gallons per year. With current operating capacity at over 3 billion gallons per year, the industry holds a vision of 6 billion gallons per year by 2030 then up to 15 billion gallons per year by 2050.[42]

Figure 19 - Vermont biodiesel consumption[43]



During the fall of 2020, PSD worked with the Vermont Fuel Dealers Association to survey its membership on volumes of biodiesel usage in the state. The survey yielded only one set of data representing BioHeat sales totaling about 4.6 million gallons of biodiesel-containing heating fuel sold in to residential, commercial, institutional, and industrial customers—well below the values reported by EIA. All other fuel sellers responding to the survey indicated they do not sell BioHeat.

According to the Vermont Fuel Dealers Association (VFDA), very few oil heat retailers in Vermont have a separate storage tank for biodiesel which allows them to create a custom blend of renewable fuel and standard #2 fuel oil. A limited number of oil heat retailers purchase gallons at the terminal rack certified as a blended product (B5, B10, etc.). However, nearly all the approximately 100 million gallons of oil heat sold in Vermont annually has some blend of biodiesel.[44]

To comply with the federal Renewable Fuel Standard (RFS), major oil companies (refiners/wholesalers) are obligated to blend renewable fuel into their downstream supply. Heating oil (also known as #2 distillate) can be blended with up to 20 percent biodiesel and still meet ASTM specifications for oil heat.

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[41] Biodiesel Producers and Production by State. Energy Information Administration. July 2020. https://www.eia.gov/biofuels/biodiesel/production/table4.pdf.
[42] A Vision of Feedstock, Donnell Rehagen, Biodiesel Magazine. October 2, 2020. http://www.biodieselmagazine.com/articles/2517192/a-vision-of-feedstocks.
[43] Source: Energy Information Administration.
[44] Email, Vermont Fuel Dealers Association, October 12, 2020.

The concentration of biodiesel in the supply of oil heat fluctuates based on those obligations as well as the price and availability of B100.

VFDA attempted to determine the average biodiesel content in a gallon of heating oil in 2016 by testing ten samples of oil heat from ten different Vermont oil heat retailers. The average content was found to be approximately 2 percent. VFDA plans on conducting a much larger study in 2021 to test the renewable content of Vermont's oil heat supply.

In absence of sufficient survey data, the Department estimates the volume of BioHeat consumed in Vermont via data from the EIA. In 2018, distillate fuel oil consumption in Vermont was approximately 197 million gallons per year.[45] Of that, heating oil accounts for about 100 million gallons. Using the 2 percent volume biodiesel estimated in 2016 by VFDA, about 2 million gallons of biodiesel was consumed in Vermont in 2018. Better estimates will need more random sampling to establish biodiesel content in distillate, implementation of a mandate for blend percentage, or disclosure of biodiesel content at the wholesale rack.

In 2019 the Northeast's heating oil industry pledged to reduce greenhouse gas emissions from heating oil 15 percent by 2023, 40 percent by 2030 and to become net-zero by 2050 (B20 by 2023, B50 by 2030, and B100 by 2050).[46]

Recent oil burner technology changes in the heating industry are helping to promote the use and production of BioHeat. For example, one of the industry's leading heating oil burner manufacturers announced that it has certified that some of their new burners will use biodiesel blends of up to 20 percent (B20).[47] This action aligns with a recent agreement in the heating fuel industry to reduce greenhouse gas emissions.

Electric Heating

Electric heating systems are not a renewable energy technology but utilize electricity generated in part by renewable energy sources. In 2019 the average Vermont utility's power supply was 66% renewable, although this number varies by utility.

Electric Resistance Baseboard

Electric baseboard is typically the most cost-effective option for installation of a heating system in a building. Conversely, it also can be one of the more expensive options for heating a building over its lifetime and has been strongly discouraged within Vermont as a heating source over preceding decades. However, if combined with deep investment in air sealing and insulation of the building shell, electric baseboard heating can be an acceptable heating technology that balances greater investment in the buildings shell with a low cost, yet effective heating technology. This approach has been modeled and adopted within the state's building energy codes. It requires a specific set of criteria to be met which allows buildings heated solely by electric baseboard to be constructed. Buildings meeting these criteria still meet the efficiency requirements required by the building energy codes.

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[45] *Energy Consumption Estimates for Selected Energy Sources in Physical Units, 2018*. Energy Information Administration.
https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/sum_use_tot.html&sid=VT

[46] *Resolution*, 2019 Northeast Industry Summit. Heating and Energizing America Trade Show, New England Fuel Institute. September 16, 2019.
https://nefi.com/files/8815/6874/3153/2019_Industry_Summit_Resolution_20190916_Final.pdf.

[47] *R.W. Beckett Announces B20 Burner Certification*. Fuel Oil News. https://fueloilnews.com/2020/09/21/r-w-beckett-announces-b20-burner-certification/.

Heat Pumps

There are several types of heat pumps. The basic technology uses electricity to run a compressor to force the phase change of a refrigerant and can be used for both heating and cooling. Heat pumps can extract heat from the ambient air outside of a building, called air-source heat pumps, or they can also use the relatively constant temperatures underground, called ground-source heat pumps. Heat pump water heaters use the same technology to extract heat from indoor air to heat water. Heat pump water heaters can directly replace conventional electric resistance water heaters and are more efficient.

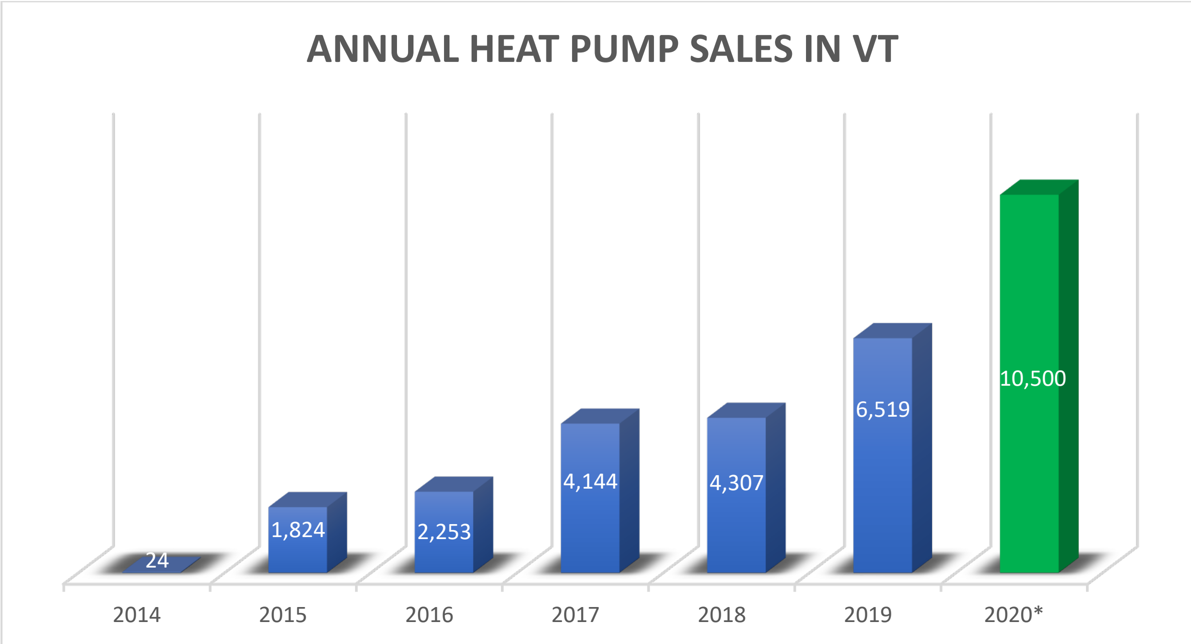
Improvements in heat pump technology have made them viable forms of heating in cold climates such as Vermont. These cold-climate heat pumps (CCHP) are the type that Vermonters are installing to help increase our use of renewable energy and to meet state GHG reduction goals. CCHPs use 40-70% less electricity than electric baseboard or plug-in resistance heaters. CCHPs have limited heat output at lower operating temperatures which means they may not always be able to supply the necessary heat to a space at the coldest outdoor temperatures, often necessitating either significant building shell improvements or maintaining another form of heating system for these cold periods. However, the efficiency and operational ranges have been increasing as the technology improves.

Ground-source heat pumps are more efficient than air-source CCHPs, but they have higher capital cost. For this reason, the market for CCHP has outpaced that of ground-source heat pumps. As a result of programs developed by the electric utilities to comply with Tier III of the RES, and incentives for more efficient CCHPs offered by EVT, there has been considerable growth in the use of this technology during the past five years.

Heat pumps can also be run in reverse to provide cooling. An evaluation titled "Cold Climate Heat Pumps in Vermont"[48] completed by the PSD in 2017 concluded that, at that time, there was a net decrease in the overall cooling load of homes due to the replacement of inefficient window AC units and the use of high-efficiency heat pumps. This study period covered 2015-2016 installations and the growth of CCHP installations in the intervening years suggests that this study may need to be updated.

[48] https://publicservice.vermont.gov/content/2017-evaluation-cold-climate-heat-pumps-vermont.

Figure 20 - Heat Pump Sales in Vermont[49]



Non-renewable Heating Fuels

Non-renewable (or fossil fuel) sources of energy account for the majority of fuels used to meet Vermont's thermal demands. These fuels include petroleum products, natural gas, and coal. Petroleum products include fuels such as distillate fuel oil (e.g., No. 2 home heating oil and diesel fuels), kerosene, and propane (also called liquified petroleum gas or LPG). 251,065,886 gallons of fuel oil, propane, and kerosene were sold in Vermont in 2019.[50] Natural gas makes up roughly 23% for thermal fuel use, although use of natural gas within the state is limited by existing distribution networks located primarily in the northwestern part of the state. Other fossil fuels (e.g., coal) supply approximately one percent of thermal energy demands.

Major Changes in the Non-renewable Heat Markets, Technologies, and Costs

Coal Change-Out Program

Coal continues to be used for heating in Vermont homes and businesses, but its use is declining. The exact amount of coal still used in Vermont is unknown, however, the Agency of Forests, Parks, and Recreation's 2019 residential fuel use survey provided estimated 931 homes in Vermont operate a coal stove or heating system. This represents 0.4 percent of households, and improvement from the fuel survey conducted in 1986, which estimated 2.4 percent, or 4,800 Vermont homes, had coal heaters.

In August 2020, the CEDF started a coal change-out program to encourage the removal of coal heating systems. Coal systems have high greenhouse gas, particulate, and other pollution emissions, especially the older systems in use in Vermont today. Replacing them with pellet heating systems helps the State to reach multiple goals of greenhouse gas reductions, cleaner air, and increased use of renewable

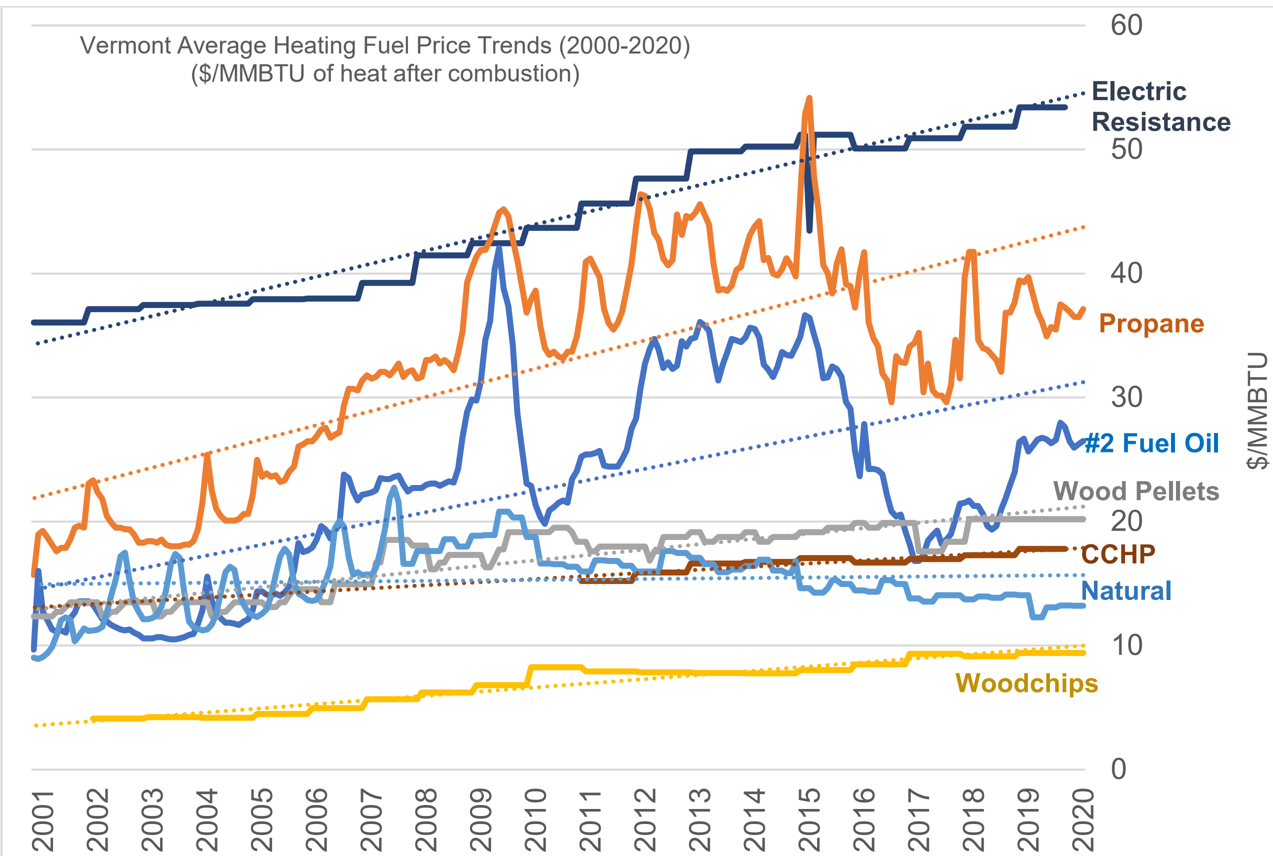
[49] These are estimated sales. On 10/1/20, 8,989 sales had been reported.
[50] Data provided by the Department of Taxes.

heating fuel. Furthermore, coal may be increasing difficult to buy as demand shrinks and suppliers stop carrying and delivering it.

Changes to Fossil Fuel Prices

Prices for fossil fuels continue to be volatile, as represented in Figure 21 which shows the historical price of thermal fuels from 2000 through 2020. The onset of the COVID-19 pandemic brought about sharp decreases in the price of many heating fuels. As illustrated by the results of the Department of Public Service's Heating Fuel Survey, the price per gallon of No. 2 heating fuel oil dropped over 30 percent between January and June 2020, with the average price in Vermont dipping as low as $1.92 per gallon in May and June 2020. The decrease in propane prices has been more moderate, dropping about 10 percent from $2.54/gallon in January 2020 to $2.28 in June 2020. While prices have rebounded moderately since the general reopening of the economy starting in May (within Vermont and elsewhere), prices for heating fuels remain low, hovering around the $2/gallon for No. 2 heating fuel and $2.28/gallon for propane.

Figure 21 - Vermont Average Heating Fuel Price Trends (2000-2020)

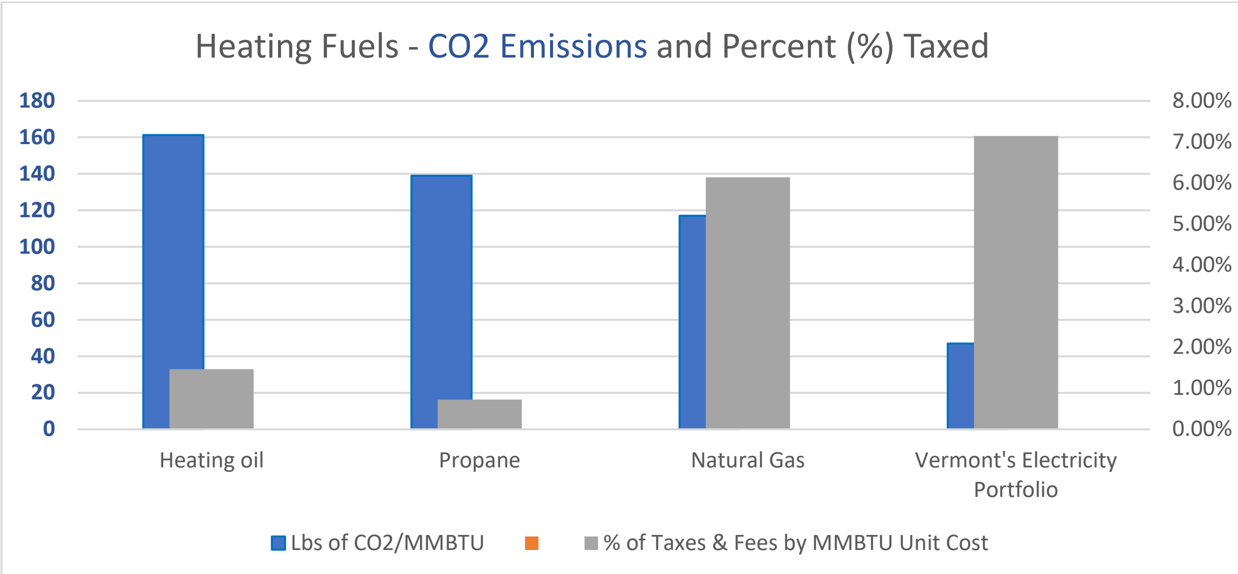


Uncertainty remains regarding the extent to which fossil fuel prices will continue to be depressed. The EIA Short Term Energy Outlook (released in October 2020)[51] suggests low prices will continue throughout at least the next year. Low prices may prove beneficial for keeping winter heating bills low for Vermonters struggling to pay utility bills through the pandemic. However, long-term low prices could negatively affect the ability of Vermont's utilities to meet Tier III requirements and related CEP goals to

[51] https://www.eia.gov/outlooks/steo/.

reduce use of fossil fuels. Without clear fuel savings from renewable resources, higher incentives are necessary to convince customers to undertake changes to their heating systems.

Figure 22 - Carbon dioxide emissions and level of taxation by heating fuel type



Recommended Policies

As discussed in the previous section, Vermont continues to make progress towards meeting the CEP goals established for the thermal sector, including achieving 30% renewable thermal energy and increasing the number of installs of electric heat pumps within the state. As programs such as utility Tier 3 programs (which offer incentives for installation of heat pumps, wood pellet stoves, and weatherization) mature, it is likely these efforts will help further advance progress towards meeting CEP goals.

Yet more work remains to be done and much of the regulatory action for achieving State energy and emissions goals has occurred in the electric sector, where policies such as the Renewable Energy Standard and Energy Efficiency Utilities have substantially reduced GHG emissions. Achieving state energy and emissions goals will require more concerted efforts to advancing renewable heating and cooling systems and reducing fossil fuel consumption in the thermal sector. This section offers several next steps that the PSD will be focusing on in the coming year.

Commission a New Wood Heating Study

In 2016 the CEDF published a baseline study on Vermont's wood heating market, focused on AWH specifically. The PSD/CEDF is considering commissioning a new wood heating study in 2021 to update the metrics collected in 2016 and determine the extent to which the local wood heating market has matured and discern the impacts of the State's efforts at promoting wood heating.

Support the Collection of More Granular Data on Fossil Fuel Sales

To accurately measure progress towards and develop plans and programs to reach the State's goals for increasing the use of renewable fuels and thermal energy efficiency, better data on the use of fossil fuels will be helpful for energy planning processes. In particular, specific data on the volume of sales of the different types of heating fuels (currently heating oil, kerosene, propane, biofuels, and others are aggregated in the data collected by the Department of Taxes).

In addition to disaggregated sales data by fuel type, more granular locational fossil fuel sales data, such as fuel sales by county of sale (e.g., based on where the fuel is delivered), would be beneficial for targeting programs. Further, this data is required by external parties such as the regional planning commissions seeking affirmative enhanced energy determinations pursuant to 24 V.S.A. § 4352. The PSD will work to establish a reliable method to disaggregate the statewide sales data to support internal and external data needs.

Support Workforce Development for Weatherization and Renewable Heating Installers

Given the price volatility of fossil fuel prices it is important to ensure that there is sufficient time and available workforce to meet a swift increase in demand for thermal efficiency and renewable heating options if a significant and sustained increase in fossil fuel prices occurs, or if the state develops a financing mechanism that substantially ramps up access to capital needed to invest in these systems. PSD can work with ACCD to develop training programs.

Consider expanding the scope of the State Energy Management Program (SEMP)

SEMP currently only works on state buildings managed by the Department of Buildings and General Services. State bond financing or a revolving loan fund could be considered to expand SEMP's projects to all the buildings in the Vermont State College and at the University of Vermont as well as municipalities. Use of any debt facilities to support such investments would require long-term funding for debt service.

VI. Transportation

Overview

Transportation fuels represents the largest category of Vermont's total energy consumption and greenhouse gas emissions. According to the Vermont Agency of Transportation's (AOT) 2019 Transportation Energy Profile,[52] approximately 5.9% of the energy consumed in the transportation sector was renewable, consisting of mostly ethanol blended into gasoline that is purchased by consumers for light duty vehicles. Biodiesel blends are available for some heavy-duty vehicles, and renewable electricity accounts for around just 0.1% of transportation fuel. The main opportunities for reducing consumption and emissions from the transportation sector lie in 1) transportation demand management, and 2) vehicle electrification.

2016 Comprehensive Energy Plan Goals

The 2016 CEP transportation goals include:

1. Reducing total transportation energy use by 20% from 2015 levels by 2025;
2. Increasing the share of renewable energy in the sector to 10% by 2025; and
3. Reducing transportation-emitted GHGs by 30% by 2025, through reduced consumption and increased renewables.

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[52] https://vtrans.vermont.gov/sites/aot/files/planning/documents/planning/The%20Vermont%20Transportation%20Energy%20Profile_2019_Final.pdf.

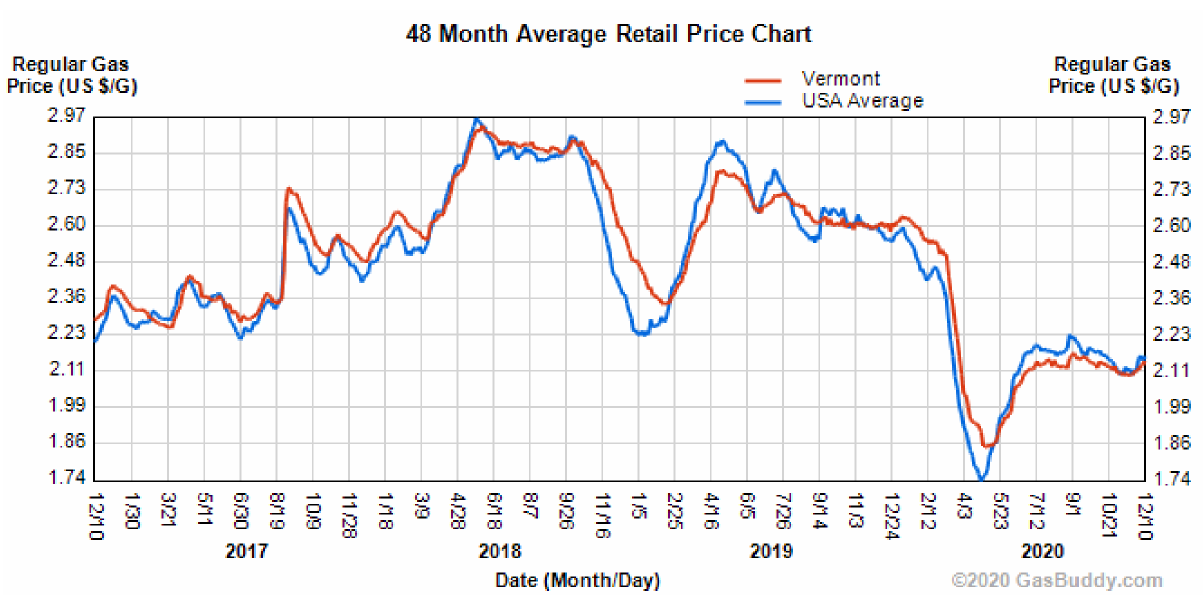
These goals can be met in a variety of ways including, but not limited to, increased fuel economy of internal combustion engine vehicles, the adoption of electric vehicles, increased use of public transit, increased participation in active transportation such as walking and biking, and actions that decrease single-occupancy vehicle trips such as expanding the availability of park-and-ride lots.

There has been limited progress in meeting the State's transportation related energy and climate goals. Renewable energy accounts for approximately 5.9% of energy in the transportation sector as of 2019.[2] The 5.9% is largely due to the presence of ethanol in gasoline that is purchased at the pump, but some share of renewable transportation fuel is attributable to electric vehicles. Additionally, while the average miles-per-gallon efficiency of vehicles statewide continues to increase, the per-capita vehicle-miles-traveled figure continues to rise. These factors provide competing pressures on the amount of energy consumed in the transportation sector in Vermont.

Transportation Fuel Prices

Gasoline and diesel prices show volatility over time. Prices remained steady in 2019 and early 2020 before falling rapidly in March 2020 as behavioral changes related to COVID-19 dramatically reduced travel and global demand for petroleum. Prices stabilized at lower levels by June 2020. While unpredictable, the EIA expects that gasoline and diesel prices will climb slightly in 2021, with average per-gallon prices around $2.27 for gasoline and $2.62 for diesel.[53] The Department of Energy estimates that the average cost of electricity in Vermont is equivalent to a gasoline price of $1.80 per gallon.[54]

Figure 23 - Average Gasoline Prices[55]



Reduction in Energy Consumption

Electric vehicles are inherently more efficient than internal combustion engines. For example, an all-electric VW Golf travels roughly four times the distance of a gasoline powered Golf for the equivalent energy from gasoline. A plug-in hybrid vehicle's efficiency falls between that of an internal combustion

[53] US Energy Information Administration. Short Term Energy Outlook Release of December 8, 2020.
[54] US Department of Energy. eGallon Price Tool. https://www.energy.gov/maps/egallon.
[55] Source: Gas Buddy LLC, December2020.

and an all-electric vehicle. However, there are other methods of reducing energy consumption within the transportation sector, as described below.

Efficiency and Fuel Mix of Vermont's Vehicle Fleet

The composition of Vermont's vehicle fleet has a significant impact on both the energy consumed and the associated GHG emissions associated. Vehicles powered by electricity or compressed natural gas (CNG), are often more efficient and have significantly lower GHG emissions. Emissions are especially lower for electric vehicles charged in Vermont where renewable generation makes up the majority of electricity mix. The table below shows the composition of Vermont's vehicle fleet by fuel type. Recent trends include an increase in plug-in electric vehicles (PEV), which includes both all-electric (AEV) and plug-in hybrid electric vehicles (PHEV), as well as hybrid electric vehicles (HEV) fueled by gasoline alone.

Figure 24 - Vermont Vehicle Fleet by Fuel Type, July 2019[56]

Fuel Type	Registered Vehicles	Share of Total	Example
Gasoline	547,199	92.2%	Subaru Forester
Diesel	31,107	5.2%	Chevy Silverado Diesel
Gasoline Hybrid	12,077	2.0%	Toyota Prius
Plug-in Hybrid Electric Vehicle (PHEV)	2,032	0.3%	Toyota RAV 4 Prime
All-electric Vehicle (AEV)	1,256	0.2%	Chevy Bolt
Propane or CNG	34	0.0%	UVM Campus Shuttle

Average fuel economy is another important metric for Vermont vehicles. Federal Corporate Average Fuel Economy (CAFE) standards support increases in the average MPG as older, less efficient vehicles are retired. Vermont's vehicles are becoming more efficient over time, albeit slowly. In Vermont, as in other states, new car purchases are increasingly sport-utility vehicles and light trucks. These vehicles are subject to less stringent federal standards than passenger cars, and their increasing popularity partially offsets overall efficiency gains across the entire vehicle fleet.

Electric vehicle efficiency is measured by Miles per Gallon Equivalent (MPGe), a metric created by the EPA for vehicles that do not use liquid fuels. The MPGe rating for a vehicle represents the number of miles the vehicle can travel using the same amount of energy that is contained in a gallon of gasoline.[6] The table below does not incorporate the MPGe rating of vehicles that do not use liquid fuels.

Public Transit, Rail, and Active Transportation

Public transit can be less energy-intensive that single-occupancy vehicles, especially on high volume routes. Transit planning in Vermont is coordinated through the Agency of Transportation's public transit policy plan.[57] The Agency expends around 5% its transportation budget on capital and operating expenses of the state's eight public transit providers.

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[56] Source: UVM Transportation Research Center, 2019 Vermont Transportation Energy Profile.

[57] Available at: https://vtrans.vermont.gov/planning/PTPP.

The Vermont Agency of Transportation develops and maintains several transportation demand management (TDM) related programs, including public transit, park and rides, rail, and bike and pedestrian programs. While the TDM program's ultimate goal is serving all Vermonters and offering transportation choices, many of these strategies improve energy efficiency in the transportation sector. Below is an overview of each TDM related program that VTrans administers with links to additional resources maintained by VTrans.

Transit Overview: The Public Transit Section of the Vermont Agency of Transportation (VTrans) provides financial and technical assistance to transit districts, transit authorities, municipal transit systems, and non-profit public transit systems. This function is carried out through the administration of state and federal programs relating to general public transportation and transit programs specific to the needs of senior citizens and persons with disabilities. $37 million was dedicated from the Transportation Fund for this purpose in FY2020. This also includes funding for commuter programs, such as Go! Vermont. For more information, please see https://vtrans.vermont.gov/public-transit.

Park and Ride Overview: Vermont is home to 31 state-owned park and ride lots (including 6 with EV charging stations) and over 70 municipal lots. The Park and Ride Program includes the development, assessment, and upgrade of park and ride facilities, coordination with transit providers, and other public information services.

Rail Overview: VTrans oversees a rail program that is charged with maintenance activities and upgrades on 305 miles of active rail lines that are owned by the State of Vermont. The state is responsible for 172 rail bridges and over 400 public highway rail crossings. The state also has two Amtrak passenger service routes that it supports financially. These services run on both privately and publicly owned railroads. For more information, please see: https://vtrans.vermont.gov/rail.

Bike and Pedestrian Overview: VTrans also delivers a Bicycle and Pedestrian (BP) Program that selects projects through a grant program which funds municipally managed bicycle and pedestrian infrastructure projects. BP also scopes studies to plan for those projects, and directly funds several others. The goal of the BP program is to support projects that complete critical gaps in local pedestrian or bicycle networks, add municipal sidewalks, and solve a critical safety problems. The budget also identifies any spending earmarked for safety education. Funding for this program in FY2021 via the Transportation Fund is approximately $17.0 million, including $3.6 million for the Lamoille Valley Rail Trail. For more information, please see: https://vtrans.vermont.gov/highway/localprojects/bike-ped.

The following chart outlines the 2016 CEP Transportation Goals and the most recent current status update. It also outlines the average annual change that must occur to be on track to reach the CEP goals. For example, to reach the 2016 CEP goal of tripling the number of state park-and-ride spaces, at minimum, 146 spaces must be added each year between 2018 and 2030. This represents an objective, albeit limited gauge for progress toward achievement of the transportation goals outlined.

Goal	Goal (Numerical)	Year	Current Status	Source	Requirement to Reach CEP Goals
Triple the number of state park-and-ride spaces	3,426	2030	1,525 (2017)[60] 1,686 (2020)	CEP Transportation Goals (2016)	Add 1901 spaces, adding at least 146 spaces each year.
Increase public transit ridership by 110%	8.7 million annual trips	2030	4.71 million annual trips (2016) 4.69 million annual trips (2017) 5.13 million annual trips (FY2019)[8]	CEP Transportation Goals (2016)	Increase ridership by 4.01 million annual trips, adding 308,462 trips each year.
Quadruple Vermont-based passenger rail trips	400,000 annual trips	2030	145,746 annual trips (2017)**[62] 149,795 (2019)[9]	CEP Transportation Goals (2016)	Increase rail trips by 254,254, adding 19,558 passenger rail trips each year.
Double the rail freight tonnage in the state	13.2 (based on 2011 figure) million tons	2030	7.3 million tons (2014) 6.7 million tons (2017)[63]	CEP Transportation Goals (2016)	Add 6.5 million tons of rail freight, adding 500,000 tons each year.
Increase the percentage of the vehicle fleet that are EVs	10% of the vehicle fleet	2025	0.3% (2016) 0.6% (2019)	CEP Transportation Goals (2016)	By 2025, an additional 9.4% of vehicles should be EVs, increasing the percentage of EVs in the fleet by 1.21% each year.
Increase the number of medium and heavy-duty vehicles powered by renewable energy	10% of vehicles	2025	4 to 10 transit and school buses A 2009 study estimated Vermont's transportation biodiesel use at	CEP Transportation Goals (2016)	By 2025, an additional 9.98% of medium and heavy-duty vehicles should be powered renewably, increasing from our current

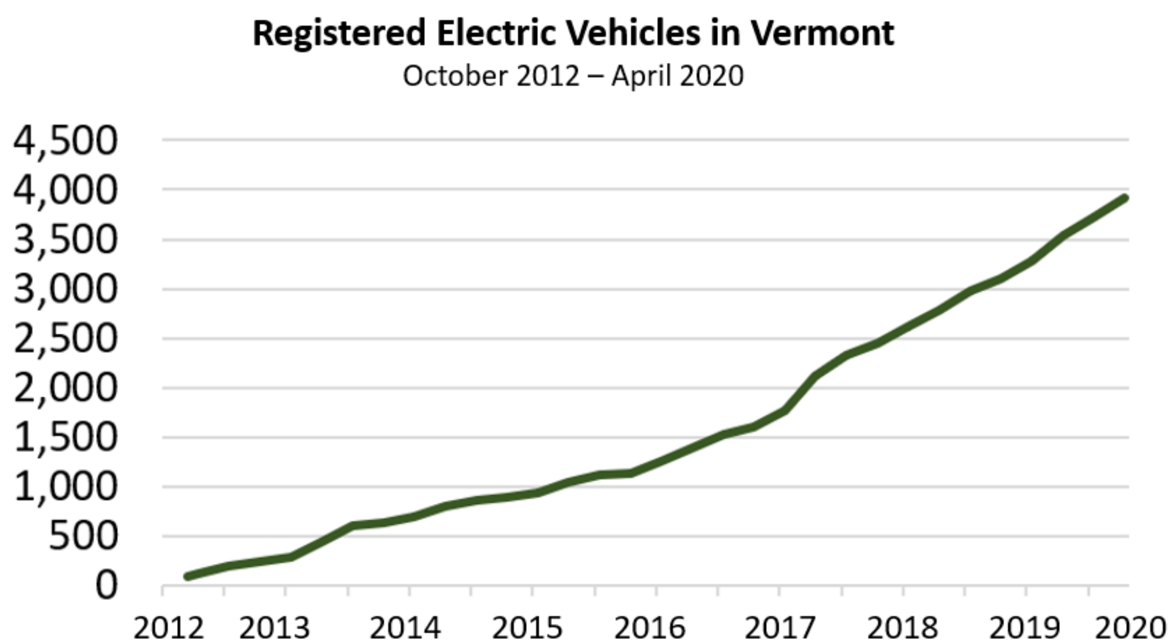
		approximately 76,000 gallons, or 0.02% of the total transportation fuel portfolio in 2008 (White, 2009).	percentage at a rate of 1.25% a year.

Renewable Energy Supply

The most promising pathway for increasing renewable energy in the transportation sector is by transitioning away from internal combustion engines toward electric vehicles. Every electric utility in Vermont offers incentives for EVs through Tier III of RES; in addition, the State of Vermont incentive program provides rebates to low- and moderate- income Vermonters. Rebates reduce the upfront cost of EVs. However, other factors affect consumers' decisions regarding EVs, including familiarity with EV fuel and operational savings, perceived availability of charging locations ("range anxiety"), and vehicle size and features. Currently, ten manufacturers offer EV models with all-wheel drive, and two additional automakers are expected to bring AWD models to Vermont by the end of 2021.

Electric vehicle registrations in Vermont continue to grow. As EVs can be powered renewably, the percent of renewable energy consumed in the transportation sector is expected to grow alongside growth in EVs. The figure below shows the growth in registrations over the past several years. Vermont ranks among the top ten states for EV adoption per capita.

Figure 25 - Electric Vehicles in Vermont[58]



While electrification for Vermont's light-duty fleet is growing in popularity, electrification of heavy-duty transportation presents greater challenges. Electric vehicle options are available for transit and school bus segment, and prototypes are in testing for freight trucks of various sizes. Reducing GHG emissions in the freight industry can be met, in part, by shifting freight to rail. In addition, there are many heavy- and

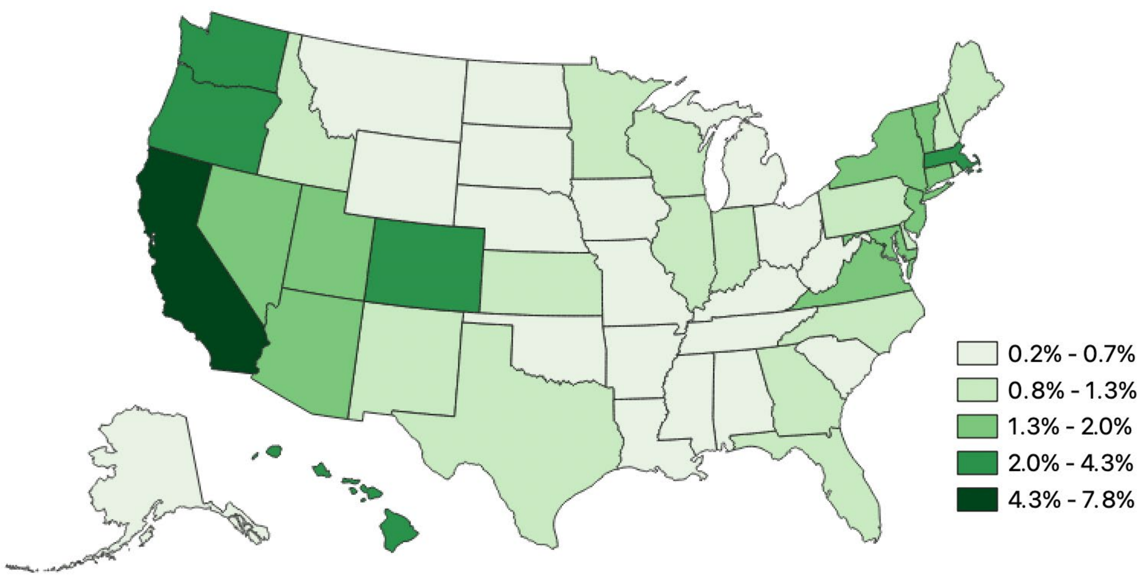
[58] Source: Vermont DMV registration data analyzed by DEC and Drive Electric Vermont.

medium-duty applications for which no electric or rail options are available. In those applications, alternative fuels—including biodiesel, ethanol, and compressed or liquefied natural gas—offer a lower-carbon alternative to gasoline and diesel, with significant GHG savings and fewer emissions. While biodiesel is preferred to natural gas for heavy- and medium-duty applications, both biodiesel and natural gas offer lower emissions than traditional diesel.

Because biodiesel can be blended with diesel and used in existing medium and heavy vehicles, biodiesel in particular offers a unique opportunity to reduce the GHG emissions of Vermont's vehicle fleet without investing in specialized vehicles, equipment, or infrastructure. Ethanol—currently added to gasoline at up to a 10% concentration—brings a mixed environmental record. Environmental concerns, including poor energy return on energy invested and the actual degree of GHG reduction make it less attractive compared to other biofuels. Compressed and liquefied natural gas also offer GHG savings compared to gasoline and diesel but renewable gas is far most costly than standard natural gas. If adopted, the use of renewable natural gas in transportation will count toward meeting Vermont's sectoral goal of deriving 10% of its energy use in transportation from renewable sources by 2025 and 80% by 2050.

Electric vehicles, including electric buses, are growing in popularity as the range of such vehicles increases and the upfront costs decline. Costs are expected to continue to decline as EV adoption rises. The graphic below shows the declines in the cost of lithium-ion batteries, one of the major cost drivers for electric vehicles, over the past several years. Model availability and variety are anticipated to drastically increase over the next few years. Most major auto manufacturers have announced plans to introduce additional EV models, especially SUVs and pickup trucks, and some have even announced goals to discontinue internal-combustion engine vehicles.

Figure 26 - Electric Vehicle Market Share by State, 2018[59]



Electric school and transit buses are already present in Vermont. With the assistance of federal grants administered by VTrans, Green Mountain Transit has acquired two full-size electric buses that operate in Chittenden County. Through a separate funding process, two smaller electric shuttle buses are expected to begin operating in Washington County within the next year. Meanwhile, the Department of Environmental Conservation is using Volkswagen Environmental Mitigation Trust funds for an electric

[59] Source: EV Adoption, 2020. Map by PSD.

school and transit bus pilot. Six electric school buses will be delivered in 2021 and two full-size electric transit buses will be begin operating in in 2021 or 2022.

Electric Vehicle Charging Stations in Vermont

A major issue for EV adoption in Vermont will be ensuring sufficient opportunities for charging the EV outside of the home. Although most of the charging for EVs currently occurs at the residence, increased adoption—particularly by renters and tourists— will require reliable, widely available charging infrastructure in Vermont. As of November 2020, there are approximately 246 publicly available charging stations in Vermont offering 714 charging ports. This is a significant increase from the 160 stations that were available in December of 2017. The 247 stations include:

- 6 locations with Level 1 charging, which charges at approximately 1.4 kW power and provides 5 miles of range per hour of charging;
- 213 locations with Level 2 charging, which charges at approximately 3-7 kW and provides roughly 10 to 20 miles of range per hour of charging; and
- 28 DC Fast Chargers, which charge at 25-150 kW and generally takes 30 minutes to provide an 80% charge.

The Drive Electric Vermont program (supported by AOT, ANR, BGS, and PSD) track publicly available charging stations in Vermont and maps them statewide.

Recommended Policies

Achieving Vermont's energy goals for the transportation sector requires reducing overall energy use, reducing greenhouse gas emissions, and shifting consumption towards renewable fuels. Replacing gas- and diesel-powered vehicles with electric vehicles (EVs) supports each of these objectives, but vehicle electrification should occur with supporting public transit and active transportation—such as walking and cycling—to maximize economic, environmental, and health benefits for Vermonters. The policy recommendations below primarily relate to EVs given their relationship with the electricity grid.

Reduce Upfront EV Costs with Continued State and Utility Rebates

The Legislature appropriated funds in 2019 and 2020 to provide a rebate to low- and moderate-income Vermonters for the purchase or lease of a new EV. The rebate reduces the upfront cost for EV buyers.

Two requirements help target this rebate to influence drivers who would not otherwise choose an EV. First, the rebate only applies to Vermonters meeting income requirements based on their annual adjusted gross income; low-income Vermonters, earning $50,000 or less, receive an enhanced rebate. Second, only electric vehicles with a base MSRP of $40,000 or below qualify for the rebate. This excludes luxury models but includes a variety of all-electric vehicles and plug-in hybrid EVs, including some all-wheel drive models.

Many distribution utilities offer additional rebates that compliment state rebates through their Energy Transformation (Tier III) Programs. The utilities also bring another way to reach customers, whether through direct advertising or through marketing materials accompanying electric bills.

Ensure broadband deployment to Allow Greater Telecommuting/Education/Medicine

One result of the pandemic is that it showed clearly how many Vermonters could transition to conducting activities remotely – including work, education, medicine. This not only served as an effective mechanism of reducing exposure to the virus, but also is expected to result in a significant reduction in vehicle miles traveled for the state. However, there is a large number of Vermonters who do not have adequate access to broadband, and continued deployment of infrastructure is necessary in order to ensure that there is equitable access to these options.

Support Upstream Efforts in the EV Market Chain

Electric vehicles are difficult to purchase at certain dealerships. Typically, manufacturers require dealers to install charging equipment, train mechanics, orient sales staff, and ensure EVs are available on their lot. These are meaningful barriers at this early stage of technology adoption, and some Vermont dealers choose not to sell EVs. Incentives to dealers and sales staff make EVs available to more Vermonters and encourage staff to explain EV performance and operating benefits compared to familiar internal combustion vehicles.

Electric efficiency programs plan to implement this approach over their three-year greenhouse gas emissions reduction programs authorized under Act 151 of 2020.

Continue EV Infrastructure Deployment Around Vermont, Including at Multiunit Dwellings

The State of Vermont has partnered with public organizations and private businesses to deploy EV supply equipment (EVSE) throughout the state, and current efforts focus on filling gaps in highway corridors with DC fast chargers. Better EV infrastructure gives confidence that EV drivers—both residents and visitors—will be able to complete timely journeys.

Additional funding for EV should prioritize remaining gaps in travel corridors and add redundancy at critical locations where a single malfunctioning unit could force users to endure much slower charging. However, a shift is also needed to ensure that chargers meet the needs of renters and multiunit residents without access to their own EVSE or assigned parking. DUs are beginning to address this issue, but strong direction from the Legislature to public and private landlords is needed to ensure that all Vermont drivers will share in the benefits that EVs offer. This could include requirements that publicly funded housing entities (as well as larger private landlords) provide access to EVSE at their properties.

Work with Distribution Utilities to Offer an EV Rates

Over the next decade, unmanaged EV charging will add upward pressure on electric rates through the increased peak load and corresponding increase in infrastructure costs necessary to handle these higher peaks. However, EV charging is a flexible load that can be managed to reduce costs for all ratepayers by avoiding capacity charges, avoiding bulk transmission charges, and avoiding or deferring transmission and distribution system upgrades. EV rate discounts that reflect the value of flexible electric vehicle charging and encourage adoption of electric vehicles.

EV rates take a number of forms. They can address residential charging, commercial charging, and/or public EVSE infrastructure. Only a few electric utilities now offer an EV-specific rate. The PSD will continue to have discussions with the DUs to propose EV rates, which would need to be approved by the Public Utility Commission. These EV rates could reflect different approaches, including: managing loads directly, through dynamic price signals that encourage customer or third-party management of loads, and/or through simple time-of-use pricing that fairly compensate the participating customer for system savings.

A discounted rate for electric vehicles would lower energy costs for customers who own or lease electric vehicles and choose to participate. Rates would be designed to cover all costs directly attributable to delivering electricity to those customers and provide a contribution to fixed costs as well, meaning the policy would lower costs for both EV owners and all other electric customers.

Encourage Major Employers to Expand Transportation Demand Management

Transportation demand management (TDM) addresses individual transportation decisions, such as how commuters get to work, using information, encouragement, and organization. In Vermont, employers offer TDM programs to help manage parking (and related maintenance costs) by promoting public transit, carpooling, walking, and cycling. Encouraging major employers to expand their TDM programs has impacts on energy use and greenhouse gas emissions. In 2016, VTrans issued a guidance document for implementing and quantifying TDM strategies appropriate for Vermont.[60]

[60] Available online at https://vtrans.vermont.gov/sites/aot/files/planning/documents/trafficresearch/VTrans%20TDM%20Guidance%20Feb%202017.pdf.

Appendices

Appendix A – Summary of Energy Services & Programs in Vermont

The information provided in this document provides a summary of State programs that contribute towards Comprehensive Energy Plan and greenhouse gas emissions goals and requirements.

The programs described below are created by statute, and/or funded with direct allocation of taxpayer or ratepayer dollars.[1] Thus, it may not represent all Vermont activity in a particular area. For example, fuel dealers may provide biofuel blends or biomass heating systems, or contractors may offer trainings outside rateof those funded by the programs below.

The program summaries are organized in the following areas: Electric Efficiency, Thermal Energy, Electrification, Electric Load Management, Intermodal Transit, and Cross-cutting. Some programs may include services in multiple topic areas; they are generally summarized once instead of repeated.

A short summary is provided for each program. The program summary is not intended to be a comprehensive description of all activities undertaken by the

program, but rather to sufficiently describe the program and direct the reader to locations where more detail may be found. To the extent available, the following information is provided for each program: current delivery agent(s), core services, enabling statute(s) if any, funding source (and amount if known), equity considerations (e.g., low-income, geographic, etc.) and identification of relevant links and materials for more information. Under the “Cross-Cutting” section, information is also provided about energy-related economic programs designed to assist Vermont’s most vulnerable populations. These offerings are important context when considering the overall delivery of energy services in Vermont.

Electric Efficiency

Energy Efficiency Utilities

The Vermont Legislature has long required that regulated utilities include “comprehensive energy efficiency programs” as part of their responsibility to deliver services to their customers at least cost, under 30 V.S.A. § 218c. Electric efficiency programs and services are currently delivered primarily through energy efficiency utilities (EEUs) that have been appointed by the PUC. The EEU’s are funded to design and deliver technical, financial, and educational services to help Vermonters overcome barriers to improving the energy efficiency of their homes, businesses, institutions, and municipal facilities. The EEUs provide financial support to retail customers, distributors, and wholesalers, as well as technical assistance across a wide variety of electric technologies, to improve the efficiency of electric consumption across sectors.

The EEUs are authorized by 30 V.S.A § 209(d).

The City of Burlington Electric Department (BED) is appointed to provide electric energy efficiency services in its electric service territory and VEIC is appointed to operate as Efficiency Vermont (EVT) to provide electric energy efficiency services for the remainder of the state. Where services overlap, BED and EVT coordinate delivery of service to BED customers.

The Public Service Department (Department) provides evaluation, measurement, and verification services to ensure claimed savings materialize.

Electric Efficiency Programs are funded by electric ratepayers through the Energy Efficiency Charge (EEC) on their bills. The EEC is set by the PUC to collect monies sufficient to fund the three-year budgets adopted following the Demand Resource Plan Proceeding. Table 1 identifies the 2021-2023 approved budgets (including Resource Acquisition, Development and Support Services (DSS), Department evaluation funds, and items such as fund audit expenses.)

Table 1: 2021-2023 Proposed Electric Energy Efficiency Charge Budgets			
EEU EEC Budgets	**2021**	**2022**	**2023**
EVT	$46,762,300	$46,814,856	$46,853,902
BED	$2,421,737	$2,336,530	$2,401,882
Total	**$49,184,037**	**$49,151,386**	**$49,255,784**

Title 30, § 209(d)(3)(B) requires the PUC establish and adjust energy efficiency charges in order to realize all reasonably available, cost-effective energy efficiency savings, with due consideration to rate impacts and several policy priorities. It requires that the PUC balance a number of considerations when setting the energy efficiency charge, including "providing the opportunity for all Vermonters to participate in efficiency and conservation programs; and targeting efficiency and conservation efforts to locations, markets, or customers where they may provide the greatest value." The PUC's three-year performance targets for EVT and BED have minimum spending and equity requirements for residential, commercial, small business, and low-income customers.

Links:
EVT – https://www.efficiencyvermont.com/
BED – https://www.burlingtonelectric.com/
Department – https://publicservice.vermont.gov/content/efficiency
PUC – https://puc.vermont.gov/energy-efficiency-utility-program (including links to current governing documents such as Order of Appointments and "Process and Administration of an Order of Appointment")

Customer Programs

The PUC has established three types of programs that qualifying customers can use to manage energy efficiency projects on their own, without going through Efficiency Vermont. Participation criteria vary; however, customers wishing to self-administer energy efficiency must submit an application to the PUC for approval.

- Energy Savings Accounts (ESA) and Energy Savings Accounts Pilot: customers paying an average annual Energy Efficiency Charge of at least $5,000 may apply to the Commission to self-administer energy efficiency through an energy savings account. In addition, Act 150 of 2018 authorized the PUC to create an ESA Pilot. Participants continue to pay their EEC and may receive that total amount back to cover the costs of energy projects, including technical support, evaluation, measurement, and verification. It is a three-year pilot, not to exceed $2 million in diverted EEC contributions. Eligible projects include electric and thermal efficiency, energy productivity, demand reduction, and storage.
- Commercial and Industrial Customer Credit Program: The Commercial and Industrial (C&I) Customer Credit Program specifically targets large commercial and

industrial electric customers desiring greater control over energy-efficiency expenditures at their facilities. This program recognizes that certain commercial and industrial customers in Vermont are committed to—and possess considerable expertise in—energy efficiency. Currently there are no participants. To be eligible to participate, the customer must have:

  - Never accepted financial incentives from a Vermont utility-sponsored efficiency program; and
  - Demonstrated a commitment to pursuing cost-effective energy efficiency on its own.

- Self-Managed Energy Efficiency Program (SMEEP): Transmission and industrial electric ratepayers[2] may apply to implement electric and thermal energy efficiency measures on their own, provided certain conditions are met. The ratepayer must have (1) at least $1.5 million in Energy Efficiency charges during calendar year 2008 or 2017; (2) a comprehensive management program with annual objectives or achievement of certification under ISO standard 14001; and (3) commitment to an annual average investment in energy efficiency and energy productivity programs of $500,000 if using 2017 or $1,000,000 if using 2008 as a baseline for EEC charges. An eligible ratepayer may participate in SMEEP instead of participating in services or initiatives offered by Vermont Energy Efficiency Utilities and would be exempt from the EEC on its bills. There are currently two SMEEP participants.

Links:
PUC: https://puc.vermont.gov/energy-efficiency-utility-program/eeu-customer-programs

State Energy Management Program
Authorized by Act 58 of 2015, the Vermont Department of Buildings and General Services has leveraged services from Efficiency Vermont to develop and deploy an internalized energy saving performance contracting model for taxpayer benefit through the State Energy Management Program (SEMP). The program's intent is to accelerate for State buildings and facilities energy management measures, implementation of efficiency and conservation, and the use of renewable energy resources. BGS is working with PSD and program partners to expand this model to address other segments of the institutional or "MUSH" market (municipal, universities, schools, and hospitals).

As provided in their annual report for FY2020, BGS successfully audited over 246,303 square feet of building space, equal to 7% of BGS's total space and facilitated an audit in additional space owned by the Vermont Department of Labor. The decrease in audited square footage, from 372,000 square feet in FY19, was a result of building closures related to COVID-19.[3] Table 2 provides the results from SEMP activities for FY2020.

Table 2. FY2020 SEMP Results					
Site	**Project Focus**	**KWH**	**MMBTU**	**First-year $ Savings**	**Lifetime $ Savings**
Numerous locations	Efficiency VT Prescriptive Projects			$19,303	
Numerous locations	Solar Net Metering			$64,809*	
Brattleboro Courthouse Energy Upgrade	Lighting and Building Envelope	42,652	282	$11,513	$230,250
White River Jct. Courthouse Lighting	LED Upgrades	10,710		$1,535	$15,348
WSOB Flexible Load Management Pilot Program	Building Heating, Ventilation, Air Conditioning (HVAC)			$1,590	$1,590
Caledonia Courthouse Energy Improvements	LED lighting, Building Heating, Ventilation, Air Conditioning (HVAC)	90,698		$15,419	$231,305
Rutland Multi-Modal Transit Center	LED Lighting and Controls	333,615		$47,057	$470,570
Totals		**477,675**	**282**	**$161,226**	**$949,063**

*Solar net metering savings are annual savings, not first year savings.

Thermal Energy

The VGS Home Retrofit Program, part of the VGS efficiency services described above, primarily focuses on higher intensity users: homes that use at least 50,000 BTUs per square foot per year for heating. The utility provides free comprehensive energy audits, rebates for a portion of the installed costs of the recommended measures, and zero-interest or low-interest loans. VGS also offers an equipment replacement program, with rebates for hot air furnaces, hot water boilers, and water heaters among other measures. Customers below the 50 kBTU/sq. ft./year threshold are eligible for a one hour walk through focused on education and engagement of the customer around their energy usage, or the customer could be referred to EVT's Home Performance with ENERGY STAR (HPwES) program. The Home Retrofit program is funded by energy efficiency charges paid by VGS customers.

Beginning in 2010, revenues from the Regional Greenhouse Gas Initiative and Vermont's participation in the Forward Capacity Market have been directed to EVT and BED for the purpose of developing unregulated fuel energy efficiency services including the Home Performance with ENERGY STAR program. Thermal efficiency services (i.e., weatherization services) are offered to owners of existing homes and small businesses, multifamily residences, residential rental properties, and mixed-use buildings. EVT and BED coordinate these programs with activities funded through the electric energy efficiency charge; which include residential and commercial new construction programs and heating system incentives.

Vermont's Weatherization Assistance Program (WAP) is administered by OEO. Its mission is "to help low-income Vermonters save energy and money by improving the energy efficiency and health and safety of their homes." The Weatherization Assistance Program started in 1976 with funding initially provided by the U.S. DOE. This federal funding was augmented in 1990, when Vermont established a permanent source of state funding through the creation of the Vermont Weatherization Trust Fund, now called the Vermont Home Weatherization Assistance Program Fund (HWAP).

Services, which are 100% funded by the program, include:

- Comprehensive "whole house" assessment of homes for energy efficiency improvements, combustion appliance issues, and indoor air quality;

- Efficiency Coaching at every home to provide enhanced client education and refer clients to all other relevant energy, health and human service programs via the ONE TOUCH electronic referral program;
- State-of-the-art building diagnostics, including blower door testing, carbon monoxide and worst-case draft testing, and heating system testing, evaluation and infrared scans; and
- "Full-service" cost effective energy-efficient retrofits, including dense-pack sidewall insulation, comprehensive air sealing, attic insulation, heating system repairs, appliance? upgrades and replacements, installation of bathroom and kitchen ventilation, furnace duct work modifications and improvements, and assurance of safely operating combustion appliances in the home.

3E Thermal's program is targeted to multifamily buildings but designed to achieve comprehensive, deep energy savings. 3E is currently funded by RGGI, FCM, and Electrical Efficiency Charge (EEC) funds through EVT. 3E also has a contract with OEO to use HWAP funds to complete multifamily projects until June of 2021.

Vermont Gas Systems – Heating and Process Fuel Efficiency

Vermont Gas Systems (VGS) has been offering efficiency services for over 20 years. In 2016, it was appointed by the PUC to serve as the natural gas EEU in its service territory. VGS offers both residential and commercial energy efficiency programs for new and existing buildings.

The VGS Residential Retrofit Program primarily focuses on higher intensity users: homes that use at least 50,000 BTUs per square foot per year for heating. The utility provides free comprehensive energy audits, rebates for a portion of the installed costs of the recommended measures, and a zero-interest or low-interest loans. VGS also offers an equipment replacement program, with rebates for hot air furnaces, hot water boilers, and water heaters, among other measures. Customers below the 50 kBTU/sq. ft./year threshold are eligible for a one hour-walk through focused on education and engagement of the customer around their energy usage, or the customer could be referred to EVT's Home Performance with ENERGY STAR (HPwES) program.

For commercial buildings, VGS offers an equipment replacement and retrofit program. VGS conducts free energy audits, offers technical assistance, zero-interest or low-interest loans for energy efficiency improvements, and rebates for certain equipment.

The Vermont Gas Efficiency Programs are funded by the EEC on gas ratepayer bills, as set by the PUC following the Demand Resource Plan Proceeding process. Table 3 describes the currently approved budgets for Vermont Gas, as well as the budgets proposed by the Department in the most recent Demand Resource Plan case.

Table 3: 2019-2023 Vermont Gas Approved and PSD Proposed Efficiency Budgets

	2019	2020	2021	2022	2023
Vermont Gas	$3,515,838	$3,576,991	$4,593,333	$5,262,600	$5,765,226

Title 30, § 209(d)(3)(B) requires the PUC establish and adjust energy efficiency charges in order to realize all reasonably available, cost-effective energy efficiency savings, with due consideration to rate impacts and several policy priorities. It requires that the PUC balance a number of considerations when setting the energy efficiency charge, including "providing the opportunity for all Vermonters to participate in efficiency and conservation programs; and targeting efficiency and conservation efforts to locations, markets, or customers where they may provide the greatest value."

Consistent with statute, both the Department and Vermont Gas separately proposed a modification to funding mechanism for 2021-2023. Under the proposals, Vermont Gas would invest its own capital in energy efficiency, allowing for all reasonably available efficiency to be acquired sooner than would otherwise occur, while mitigating impacts to efficiency rates.

VGS – https://www.vermontgas.com/save-money-energy/energy-efficiency-programs/
Department – https://publicservice.vermont.gov/content/efficiency
PUC – https://puc.vermont.gov/energy-efficiency-utility-program (including links to current governing documents such as Order of Appointments and "Process and Administration of an Order of Appointment")

Efficiency Vermont and Burlington Electric Department – Heating and Process Fuel Efficiency
Beginning in 2010, revenues from the Regional Greenhouse Gas Initiative and Vermont's electric efficiency savings portfolio participation in the Forward Capacity Market have been directed to EVT and BED for the purpose of developing unregulated fuel energy efficiency services. Thermal efficiency services (weatherization services) are offered to homeowners (for existing homes) and to owners of small businesses, multifamily residences, residential rental properties, and mixed-use buildings. EVT and BED coordinate these programs with activities funded through the electric energy efficiency charge; these have included residential and commercial new construction programs and heating system incentives. EVT also provides training, quality assurance, and marketing assistance for contractors, and maintains a statewide network of certified energy-efficiency service contractors on its website.

In addition to building weatherization services as described above some of the Thermal Energy and Process Fuel (TEPF) funds are directed to non-weatherization services. EVT's Business Existing Facilities programs may include snowmaking upgrades, maple sap reverse osmosis, heat recovery and space heating controls, ventilation improvements, HVAC system optimization, burner controls, industrial process heat recovery, and steam trap repair and replacement. Efficient Products programs may include heat pump water heaters, smart thermostats, and low-E storm windows, as well as do-it-yourself home weatherization products for insulating and air sealing. BED has little potential in this space because its territory significantly overlaps with VGS territory, and TEPF funds are prohibited from being used for regulated fuel customers, however a recent statutory change enables BED to use TEPF funds for district heating if possible.

Title 30, § 209(e) directs funding to Thermal and Process fuel efficiency. The Order of Appointments for BED and EVT describe each EEUs' responsibilities. Table 4 shows funding for EVT and BED resource acquisition programs.

Table 4: Proposed Thermal and Process Fuel Efficiency EEU RA Budgets

	2021	2022	2023
EVT	$7,023,500	$7,023,500	$7,023,500
BED	$494,263	$460,895	$441,785

PUC three-year performance targets for EVT, BED, and VGS include equity minimum spending requirements for sector, small business, and low-income customers.

Links: See above links for electric efficiency, under Section I.A.

Weatherization – Low-income

Vermont's Weatherization Assistance Program (WAP) was created by 33 V.S.A. § 2502 and is administered by the Office of Economic Opportunity (OEO). Its mission is "to help low-income Vermonters save energy, thus money, by improving the energy efficiency and health and safety of their homes." The Weatherization Assistance Program was started in 1976, with funding initially provided by the U.S. DOE. This federal funding was augmented in 1990, when Vermont established a permanent source of state funding through the creation of the Vermont Weatherization Trust Fund, now called the Vermont Home Weatherization Assistance Program Fund (HWAP).

Title 33, § 2503 establishes a fuel tax[4] that currently yields about $10.2 million in revenue. All funds are statutorily committed to the Home Weatherization Assistance Program Fund, although the legislature has approved a 1:1 swap with LIHEAP funds to meet the policy goals of the fuel assistance program without additional financial obligation. In addition, the program also receives approximately $1,400,000/year in formula funding from the U.S. DOE Weatherization Assistance Program.

Services, which are 100% funded by the program, include:

- Comprehensive "whole house" assessment of homes for energy efficiency improvements, combustion appliance issues and indoor air quality;
- Efficiency Coaching at every home to provide enhanced client education and refer clients to all other relevant energy, health and human service programs via the ONE TOUCH electronic referral program.
- State-of-the-art building diagnostics, including blower door testing, carbon monoxide and worst-case draft testing, and heating system testing and evaluation and infrared scans; and
- "Full-service" cost effective energy-efficient retrofits, including dense-pack sidewall insulation, comprehensive air sealing, attic insulation, heating system repairs, upgrades and replacements, installation of bathroom and kitchen ventilation, furnace duct work modifications and improvements, and assurance of safely operating combustion appliances in the home.

To participate, households must meet income eligibility guidelines listed by the OEO. These are currently 200% of the federal poverty level or less (DOE guidelines), or 80% of the state's median income or less (HWAP guidelines). Eligibility is determined at each regional WAP office.

Links:

VT WAP - https://dcf.vermont.gov/benefits/weatherization

Clean Energy Development Fund (CEDF) – Advanced Wood Heating

In 2005, the Vermont General Assembly established the Vermont Clean Energy Development Fund (CEDF) through Act 74 (30 V.S.A. § 8015). In recent years, the Fund has focused on advanced wood heating initiatives. The CEDF has budgeted over $1.2 million in fiscal year 2021 to continue incentivizing advanced wood heating installations. This includes incentives for automated pellet boilers for heating of residential, institutional, and replacement of coal-fired boilers for wood heating systems certified to meet EPA's new 2020 stove standards. The CEDF ceased providing incentives for wood and pellet stoves in 2020, but these systems continue to receive incentives via EVT's TEPF Existing Homes program.

The CEDF will also provide $331K in grants made in FY20 to three businesses that support the supply side of local bulk pellet heating market.

In FY21, the CEDF has allocated over $500k of American Recovery and Reinvestment Act (ARRA) funds for two programs to support the installation of wood heating in low-income Vermonter's homes. One program operates through a MOU between the CEDF with the Office of Economic Opportunity (OEO) and the other is with NeighborWorks of Western Vermont.

The CEDF does not have on-going funding to continue its wood heating incentive programs. Thus, CEDF funding should not be counted on for future market transformation impacts.
Links:
CEDF – https://publicservice.vermont.gov/renewable_energy/cedf

Electrification

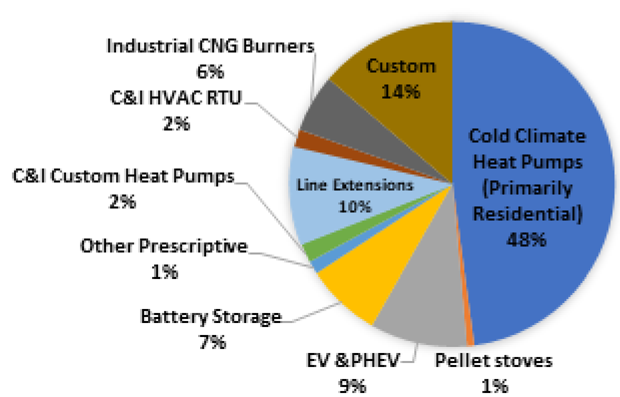
Renewable Energy Standard – Tier III programs

30 V.S.A. § 8004 establishes the Renewable Energy Standard, and § 8005 defines the three tiers of compliance for Distribution Utilities (DUs): Tier I covers utility-scale renewable generation, Tier II is for distributed renewable generation and Tier III sets goals for "energy transformation." Tier III requires utilities to acquire MWh*e* (Megawatt hour equivalent) savings of 2% of DUs retail sales in 2017, increasing by an additional two-thirds of a percent each subsequent year.[5]

Broadly, energy transformation projects are those that reduce fossil fuel consumed by customers of a distribution utility (DU), including by electrification of thermal energy systems and purchase of electric vehicles. Increases in distributed renewable energy generation above RES Tier II requirements are also eligible to apply to Tier III requirements. Tier III Requirements have been met mainly with electrification measures, although it is important to note that weatherization measures are explicitly identified as eligible Tier III measures. Some utilities offer incentives for Weatherization or electrification occurring in a home that has met certain building criteria. The DUs to date have funded programs, through upstream or direct incentives as well as technical assistance, to promote cold-climate heat pumps, electric vehicles, electric buses, EV charging stations, battery storage, line extensions to diesel generator-powered maple syrup producers and lumber mills, and other custom projects that reduce fossil fuel use. The cost of the Tier III programs is embedded in DU rates. Figure 1 provides a summary of primary Tier III measures implemented by the DUs in compliance with Tier III for 2020, by percent of total savings.

Cold Climate Heat Pump measures dominated the profile. Measures such as electric vehicle charging stations and weatherization accounted for less than 1% of the total savings and are therefore not represented on the below chart.

Figure 1:2020 Tier III Savings Profile



Links: See Utility Tier III Plans and Tier III Compliance Reports available via ePUC

Electric Vehicles

Vermont supports vehicle electrification through direct vehicle incentives, charging infrastructure funding, Tier III incentives for vehicles and controllable chargers, and education and marketing. The 2019 Transportation Bill (Act 59 of 2019) established three programs for income-qualified Vermonters. The bill created a high fuel efficiency used-vehicle incentive program and an emissions system repair program. The bill also authorized at least $1,100,000 to support an incentive program for the purchase or lease of new plug-in electric vehicle (PEVs). The $1,100,000 in incentives were fully subscribed between December 2019 and October 2020 to provide point-of-sale or direct-to-customer rebates for nearly 350 electric vehicles. The FY2021 state appropriations bill (Act 154 of 2020) added an additional $950,000 for PEV incentives.

Nearly every distribution utility offers Tier III incentives for the purchase or lease of PEVs. During 2019, around 750 new and used vehicle purchases received rebates funded under Tier III programs.

In addition to offering Tier III incentives, electric utilities also support electric vehicle adoption by offering discounted rates for EVs and by supporting EV infrastructure investment. Green Mountain Power, Burlington Electric Department, and Stowe Electric Department, for example, maintain EV public charging locations in their service territories. In 2020, Green Mountain Power launched a pilot program for “make ready” infrastructure, offering up to spend $40,000 at 20 locations around its territory to prepare electric distribution equipment to host DC fast charging equipment. Charging location operators remain responsible for installing and maintaining the EVSE equipment.

State efforts also support new electric vehicle infrastructure. Approximately $2.8 million in grants have been awarded to expand Vermont’s network of EVSE using funds from partial settlements of Volkswagen’s violations of the Clean Air Act. The final round of funding—totaling around $1 million—will be used to build 11 stations offering both Level 2 charging and DC fast charging (with nameplate charging capacities ranging from 50 to 150 kW). The 2020 Capital Construction Act authorizes $750,000 for additional EVSE stations. The Act prioritizes filling gaps in the state’s network of DC fast charging stations.

Volkswagen Environmental Mitigation Trust funds are also being used for an electric school and transit bus pilot. Six electric school buses will be delivered in 2021 and two full-size electric transit buses will be delivered in 2021 or 2022.

VTrans, with the assistance of federal funding, has also pursued the purchase of electric buses. Two full-size transit buses and two cutaway buses have begun operating—or will begin over the next year—and VTrans continues to support public transit electrification as funding allows.

Drive Electric Vermont (DEV) is the statewide coordinator for electric vehicle outreach, tracking, and data collection. DEV is supported each year by the Agency of Natural Resources and VTrans, along with the Department. DEV manages education and marketing to consumers in Vermont, as well as technical assistance to vehicle dealers, municipalities, Regional Planning Commissions, and the State. DEV’s website offers a map showing all publicly available EV charging stations in Vermont, a consumer-focused interactive listing of PEVs available for sale in the state, and details about utility, state, and other incentives. For FY2021, state agencies are providing $80,000 to Drive Electric Vermont (DEV).

Links:

Drive Electric Vermont – https://www.driveelectricvt.com

VTrans Statewide Vehicle Incentive Programs – https://vtrans.vermont.gov/planning/projects-programs/vehicle-incentives

Electric Load Management

Load Management

Load management is enabled by the foundational Advanced Metering Infrastructure (AMI, or smart meter) investment made by utilities. Investment costs are defrayed by American Recovery and

Reinvestment Act (ARRA) grant funding. More than 80% of the state's meters are now digital. Using AMI in conjunction with data analytics and other emerging control and communications platforms, the utilities, their customers, and/or third parties can actively manage customer loads across residential, commercial, and industrial sectors. This reduces system costs. Utilities are also examining and, in some cases, implementing rate design solutions that enable customers to actively respond by reducing their demand in response to price signals. (Examples of such solutions include time-of-use rates, smart rates, and even energy use feedback, as discussed below).

For example, BED's packetized energy management pilot program controls water heating devices. This helps balance energy supply and demand in real time, while enabling BED to evaluate whether or not coordinating energy consumption of equipment in people's homes can better balance the supply of generation and demand for electricity, reducing costs while improving service to customers. Washington Electric Cooperative's (WEC) "Powershift" pilot, jointly implemented with EVT, aims to test the ability of cold climate heat pumps and water heaters to shift load during peaks and other high cost times, by using two different control platforms to aggregate and dispatch resources. Green Mountain Power (GMP) is piloting the use of distributed energy resources to use controllable load to manage fluctuating demands in the commercial and industrial sector, for example using thermal or ice storage or load shifting.

GMP aggregates distributed energy resources to reduce demand through pilots such as this as enabled by its multi-year rate plan, tariffs, RES Tier III programs, and other capital projects. To manage these resources, it employs several cloud-based, shared-access control platforms to connect to these resources. The resources are, then aggregated and dispatched, to reduce system peaks. One platform is used to manage the fleet of heat pumps, water heaters, EV chargers, and non-Tesla battery storage systems. A proprietary Tesla software is used to manage the Tesla Powerwall (residential-scale) and Powerpack (utility-scale) resources.

Utility funding for load management initiatives is embedded in utility rates and based upon whether the service provides a net benefit. Many of GMP's pilot programs use a shared-cost, shared-value approach. For example, in the Powerwall pilots, customers pay a fixed monthly price (e.g., $15/month) for access to the storage capability during outages. This defrays the cost to GMP of deploying the systems that, when aggregated, are dispatched to reduce system peaks for the benefit of all customers. Software platforms, licensing fees, device integration, administrative costs, and any API[6] fees are incorporated into the overall program delivery cost. The structure of such categories and costs can vary, from annual subscription fees to per battery fees, depending on the vendor, the number of resources connected, and other variables.

To the extent that there are net benefits to these measures, there are generally not specific equity considerations for these programs as currently designed. A VLITE[7] grant supported deployment of 100 Powerwall systems free of charge to low-income customers with significant need for backup power reliability due to health and mobility issues.

Links:

WEC PowerShift – https://www.efficiencyvermont.com/powershift

BED Packetized Energy Program – https://burlingtonelectric.com/hotwater

GMP's Multi-Year Regulation Plan – https://greenmountainpower.com/regulatory/filings/2019-multi-year-regulation-plan/

Department report on Energy Storage – https://publicservice.vermont.gov/content/energy-storage-report-pursuant-act-53-2017

Rate Design

Rate design can set the foundation for customers' engagement with regulated fuel service delivery. Historically rate design has been used to send a strong conservation price signal through inclining block rate designs and high usage charges. In broad terms Vermont residential consumers receive a retail price signal that typically ranges from 16 to 23 cents per kWh (lower for some municipalities), even while the direct costs of underlying wholesale products and bulk transmission services range between 7 and 8 cents per kWh.

Vermont utilities have historically offered special prices to customers in exchange for load control. As mentioned above, utility managed or controlled loads including load management, hold the potential to minimize system costs. Many Vermont utilities have offered some form of water heater-controlled load program. GMP offers various forms of dynamic prices to residential and commercial customers, and in 2020 began offering a special Electric Vehicle charging rate for their residential customers. BED offers a deeply discounted Electric Vehicle charging rate in exchange for some measure of load control. Vermont Gas offers interruptible rates to commercial and industrial customers. All utilities rely on demand charges to encourage conservation of commercial and industrial customer peak loads. Three utilities extend those charges to residential customers.

In 2020, the Department coordinated a U.S. DOE-supported Rate Design Initiative (RDI) that gathered insights from utilities and stakeholders on advanced forms of retail price signals to encourage a more dynamic environment aimed at reducing system costs (including GHG emissions), while also spurring beneficial electrification and potentially new business models and players. These commercial providers and market participants, including building contractors and financial institutions, play a key role in the delivery of managed load and energy programs and services, as they provide capital, retail products, and contractor services. The results of the 9-month initiative including meeting materials, the final report and recommendations can be found at the RDI website below.

The study that emerged from the RDI analyzed two types of innovative load shape management tools: rate design and direct load control via the utility or a third party. Recommendations include (1) recognizing the role that rates can play to manage future costs through price signals that can change consumer behavior; (2) implementation of improved rate designs may help overcome program enrollment challenges; (3) electric rates should target certain types of loads that are more responsive to price signals; (4) marketing plays an important role and should be supported; and (5) utilities and state regulators should look to new business/service models as technologies evolve that should allow and encourage participation of third parties in the market as partners to utilities and their customers. The Department will continue to build on the progress made through this initiative through its role as the state regulator and energy office.

Links:

PSD Rate Design Initiative – https://publicservice.vermont.gov/content/rate-design-initiative

Intermodal Transit

Public Transit

The Public Transit Section of the Vermont Agency of Transportation (VTrans) provides financial and technical assistance to transit districts, transit authorities, municipal transit systems, and non-profit public transit systems. This function is carried out through the administration of state and federal programs relating to general public transportation and transit programs specific to the needs of senior citizens and persons with disabilities.

The Legislature (Title 24, Chapter 126) charges VTrans with the following goals:

1. Provision for basic mobility for transit-dependent persons, as defined in the current public transit policy plan, including meeting the performance standards for urban, suburban, and rural areas. The density of a service area's population is an important factor in determining whether the service offered is fixed route, demand-response, or volunteer drivers.
2. Expanding public transit service in rural areas and increasing ridership statewide.
3. Access to employment, including creation of demand-response service.

4. Congestion mitigation to preserve air quality, decrease greenhouse gas emissions, and sustain the highway network.
5. Advancement of economic development objectives, including services for workers and visitors that support the travel and tourism industry.

For FY2021, the Transportation Fund dedicates $39 million to public transit. This includes funding for commuter programs, such as Go! Vermont. Go Vermont is a “one-click/one-call” resource for efficient transportation options throughout Vermont, offering an automated carpool matching service, subsidized vanpools, and program support for the Way to Go! School challenge and regional Transportation Management Associations (TMAs). Funds are used to invest in technologies such as trip planners and the Automated Vehicle Location services. Financial support is provided to Local Motion, Vermont Energy Education program, and other organizations who support efficient transportation programs and approaches. In addition to the seven transit providers providing regional fixed route and demand response service around Vermont, VTrans support the Vermont Translines and Vermont Shires Connect intercity routes serving airport, rail, and bus terminals in adjoining states.

Links:

Vermont Public Transit Policy Plan – https://vtrans.vermont.gov/planning/PTPP

Go! Vermont – https://www.connectingcommuters.org

Bike & Pedestrian

The mission of the Bike and Pedestrian Program (BP) is to enable Vermont residents and visitors to walk and ride bicycles safely and conveniently. Authorized under 19 V.S.A. § 2302, the program works to achieve this mission through a multitude of collaborative design, planning and funding efforts. The Bike/Ped (BP) program awards annual grants which fund municipally managed bicycle and pedestrian infrastructure projects. BP also scopes studies to plan for those projects, and directly funds several others. The goal of the BP program is to support projects that complete critical gaps in local pedestrian or bicycle networks, and/or solve critical safety problems. The budget also identifies any spending earmarked for safety education.

The BP program also ensures that biking and walking are considered as part of all VTrans projects (e.g., shoulders on roads, sidewalks on bridges, etc.). BP also coordinates with other State agencies including ACCD on programs and initiatives that support walking and biking, VDH around increased physical activity, and FPR on recreation trails projects.

Funding for this program in FY2020 via the Transportation Fund is approximately $14.7 million; current allocations decline over time.

Links:

https://vtrans.vermont.gov/highway/local-projects/bike-ped

Rail

VTrans oversees a rail program that manages the 305 miles of active rail lines that are owned by the State of Vermont (an additional 273 miles are privately owned.) Management activities focus on upgrading track, maintaining each of the 172 rail bridges on the state-owned system, and maintaining over 400 public highway rail crossings. VTrans completed 47 rail projects on state- and privately-owned rail lines during 2019. (Authorization for rails falls under Title 5, Chapters 56 and 58.)

VTrans also provides financial support for both Amtrak passenger service routes, the Vermonter and the Ethan Allen Express. While service was suspended for much of 2020 due to COVID-19, in 2019, passenger rail stations in Vermont recorded over 95,000 boardings and alightings. Ethan Allen Express extended service to Burlington is expected to begin in 2021. For FY2021, $31 million is budgeted for rail infrastructure throughout Vermont, including $11 million designated for passenger rail service and related projects.

Cross-Cutting

Building Energy Standards

Vermont has both residential (RBES) and commercial (CBES) building energy standards. The residential energy code has been in effect since 1997, the commercial energy code since 2007. Both standards are based on the model building energy code the 'International Energy Conservation Code (IECC)', produced by the International Code Council with the support of the Department of Energy. The IECC is updated every three years, and Vermont statute[8] calls for an energy code update process to begin promptly thereafter. The update process consists of an extensive review of the new IECC and presentation and discussion of its new provisions at numerous public and stakeholder meetings, to gather recommendations and comments for Vermont-specific modifications. These modifications to the IECC are then adopted through the state rulemaking process.

The Department was given the authority to create and adopt a residential stretch code through Act 89, passed in 2013. Act 89 defines stretch code as "a building energy code …that achieves greater energy savings than the RBES" (the base code). There is no requirement in the code to achieve a certain percentage of greater efficiency. Act 89 also required that the stretch code apply to all Act 250 projects, and it can also be adopted by municipalities. As of September 1, 2020, the Department has adopted updated building energy standards for both commercial and residential construction which includes an updated residential stretch code.

Additionally, the commercial and residential base codes and the residential stretch code have electric vehicle charging requirements. These include having a socket capable of providing either Level 1 or Level 2 charging equipment for a specific number of spaces as well as having additional spaces 'EV Ready'. The exact number of spaces required varies upon the building type and size of the parking area.

The Department funds the code update process through State Energy Program allocations. [9] There is typically an increase in cost to construct new buildings to meet each revised version of the building energy standards. There may also be a cost to builders, architects, and others in the building sector to get up-to-date on new standards. EVT budgets funds for energy standards related work. This includes hosting the Energy Code Assistance Center, distributing energy standards materials, and hosting trainings on the standards.

The residential energy code has been in effect since 1997, the commercial energy code since 2007. Both standards are based on the widely used International Energy Conservation Code (IECC), produced by the International Code Council. The IECC is updated every three years, and Vermont statute calls for an energy code update process to begin promptly thereafter. The update process consists of review of the new IECC and presentation and discussion of its new provisions at public and stakeholder meetings, to gather recommendations for Vermont-specific modifications. These modifications to the IECC are then adopted through the state rulemaking process.

The 2020 Residential Building Energy Standards (RBES) includes all the International Energy Conservation Code (IECC) 2018 energy efficiency requirements as well as select language updates and additional, more stringent Vermont energy efficiency requirements. The new standards include the following updates: improved insulation levels; improved window U-values; air leakage (blower door testing) required; EV charging infrastructure required for multifamily buildings of 10 or more units and encouraged for all buildings; Solar ready design encouraged; more high efficiency lighting; and more efficient ventilation fans.

Act 89 of 2013 gave the Vermont Public Service Department the authority to develop stretch codes, which apply to all residential Act 250 projects. Additionally, municipalities can adopt the stretch code for their jurisdiction. The state's Residential Stretch Energy Code went into effect December 1, 2015 and was updated in 2019 with a September 1, 2020 effective date. The 2020 RBES Stretch code includes solar ready requirements and EV charging infrastructure required for single family housing and

multifamily buildings of 10 or more units. Both Residential Base and Stretch Energy Codes also allow renewable energy to be used to meet the target Home Energy Rating Scores for compliance.
The Department also updated the Commercial Building Energy Standards (CBES), which took effect on September 1, 2020. The 2020 CBES is based on the 2018 IECC and the ASHRAE Standard 90.1-2016. The commercial code also includes Vermont specific additions such as more stringent envelope, mechanical, and lighting requirements as well as solar and electric vehicle infrastructure requirements. Due to the highly varied nature of commercial buildings in terms of use, types, and sizes it was not practical to assign specific dollar values to the changes for the new CBES requirements. Instead changes to the code were modeled for four building types. The totality of the proposed changes to the standards are expected to impact commercial property owners and developers by causing moderate initial increases in building construction costs with lifetime savings well in excess of these costs. The simple payback for all building types is expected to be at most 9 years (and often shorter), with returns on investment of at least 11% (and often higher).
The Department plans to host an Energy Code Collaborative with stakeholders in early 2021 to discuss issues that were brought up during the energy code update process that were not resolved at the time such as looking at embedded carbon in construction materials and energy code enforcement. The Code Collaborative is expected to also discuss potential paths for Vermont energy code progression to achieve the Comprehensive Energy Plan goal of having all new buildings constructed to net-zero design by 2030.

Links:
Department webpages on Building Energy Standards – https://publicservice.vermont.gov/content/building-energy-standards

LIHEAP
Title 33, § 2604 created the Home Heating Fuel Assistance Program, known as the Low-Income Home Energy Assistance Program (LIHEAP). LIHEAP assists households with low incomes, particularly those with the lowest incomes that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs. It provides federally funded assistance in managing costs associated with home energy bills; energy crises; and weatherization and energy-related minor home repair.

Congress established the formula for distributing funds to grantees based primarily on each state’s weather, fuel prices, and low-income population. The Fuel Assistance Program’s purpose is to secure the safety and health of low-income Vermonters by providing essential home heating assistance. Grantees can also transfer up to 15% of their funding to the weatherization assistance program. In Vermont, while 15% of funds are used for weatherization assistance, revenues are replaced with revenue from the Weatherization Assistance Program Fund (see Section II.C, above) to cover LIHEAP administrative costs that are above the federal administrative cost cap. Participants’ gross household income must be equal to or less than 185% of the federal poverty level, based on household size, regardless of the resources (e.g., savings, retirement accounts, property).

Federal Funding for FY 2020 is $20,903,527. Congress allocated an additional $900 million in supplemental funding for LIHEAP through the CARES Act to help “prevent, prepare for, or respond to” home energy needs surrounding the national emergency created by COVID-19.[10] Of that funding, Vermont received $5,073,509 in May 2020.[11]

Links:

Department of Children and Families Fuel Assistance – https://dcf.vermont.gov/benefits/fuel-assistance

Energy Assistance Program

There are currently two Energy Assistance Programs (EAPs) that assist lower-income Vermont households in affording their energy needs. The programs are available to GMP and VGS customers. GMP customers that have gross monthly household income at or below 150% of the federal poverty level will receive a 25% discount on their customer and energy charges each month. VGS customers that have a gross monthly household income at or below 185% of the federal poverty level will receive a 20% discount on their natural gas bill.

Links:
Agency of Human Services, Department for Children and Families – https://dcf.vermont.gov/benefits/eap
Green Mountain Power – https://greenmountainpower.com/help/billing-payments/what-is-the-energy-assistance-program-eap/
Vermont Gas Systems – https://www.vermontgas.com/save-money-energy/energy-efficiency-programs/assistance-programs/

Federal Incentives

The Business Investment Tax Credit (ITC) is available for commercial entities that invest in renewable energy. Table 5 summarizes the eligible technologies and the credit percentage available based upon investment dates.

Table 5: Business Investment Tax Credit Eligibility and Percentage

Technology	12/31/19	12/31/20	12/31/21	12/31/22	Future Years
Solar PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	26%	22%	10%	10%
Large Wind	12%	N/A	N/A	N/A	N/A

The Renewable Electricity Production Tax Credit is an inflation-adjusted, per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005. The tax credit amount is $0.015 per kWh in 1993 dollars for some technologies and half of that amount for others. The Internal Revenue Service (IRS) publishes the inflation adjustment factor no later than April 1 each year in the Federal Registrar. Renewable energy equipment can qualify for accelerated rates of depreciation under the Modified Accelerated Cost-Recovery System (MACRS) established by Congress in 1986 and subsequently updated several times. In December 2015, the PATH Act included a five-year extension of 50% bonus depreciation through 2017 followed by a phase out down to 40% in 2018, 30% bonus depreciation in 2019, and 0% in 2020 and beyond. The Tax Cuts and Jobs Act of 2018 increased the bonus depreciation to 100% for qualified property placed in service after September 27, 2017 and before January 1. 2023.[12] Bonus depreciation rates go down to 80% for 2023, 60% for 2024, 40% for 2025, and 20% for property placed in service in 2026.[13]

The Residential Renewable Tax Credit was initially available to other forms of renewable energy. However, since 2016 it has only been available to solar thermal and photovoltaic installations. The percentage available is listed below and decreases in the out years.

- 30% for systems placed in service by 12/31/2019
- 26% for systems placed in service after 12/31/2019 and before 01/01/2021
- 22% for systems placed in service after 12/31/2020 and before 01/01/2022

Links:
IRS – https://www.irs.gov/newsroom/new-rules-and-limitations-for-depreciation-and-expensing-under-the-tax-cuts-and-jobs-act

State Incentives

The net-metering program (30 V.S.A. § 8010) provides a mechanism for Vermont electric customers to generate their own electricity to offset electric bills. The State sets the rate these facilities are compensated for the power they produce. The PUC and the PSD review these rates on a biennial basis and the rates have been decreasing over the past several years and are expected to continue to decrease. New net metering projects are currently compensated at a rate of up to 17.4 cents/kWh whereas utility projects, Standard Offer projects or bilateral contracts all come in around 8-10 cents/kWh.

In 2009, the State established the Standard Offer Program (30 V.S.A § 8005a), designed to provide a financing mechanism for small-scale renewable energy projects in Vermont. Each year, the program solicits a pre-determined amount of renewable capacity through a Request for Proposals (RFP). Long-term, fixed priced contracts are awarded to generators through the RFP process, which was designed to leverage competition and result in competitive prices. The original program cap was set to 50 MW and subsequently amended via Act 170 of 2012 to its current program capacity of 127.5 MW.

Links:
Department Net Metering – https://publicservice.vermont.gov/renewable_energy/net_metering
Department Standard Offer – https://publicservice.vermont.gov/renewable_energy/standardoffer

Vermont Small Hydropower Assistance Program

The Vermont Small Hydropower Assistance Program (VSHAP) was established to help Vermonters make sense of state and federal regulatory requirements for hydropower projects, and to provide some assistance to developers of hydropower projects that meet certain criteria for limited resource impacts in navigating those requirements. Project developers do not have to participate in the program, which was developed by the Department, Agency of Natural Resources, and Agency of Commerce and Community Development in response to Act 165 of 2012. Several small hydropower projects have been developed in Vermont in the last six years without participating formally in the program, and others are in various exploratory phases. The program background and application documents can provide helpful resources to those interested in adding hydropower to existing dams, or repowering formerly powered sites, as both situations likely require a permit (called a license or exemption) from the Federal Energy Regulatory Commission by virtue of affecting interstate commerce (by connecting to the grid) at so-called navigable waterways. No new applications were received in 2020 to date.

Links:
Vermont Small Hydropower Assistance Program - https://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Resources/Hydro/VT%20Small%20Hydropower%20Assistance%20Program%20Overview.pdf

Appendix B - Relative Cost of Carbon Reduction Methodology

Measures Included

The measures analyzed in the model include these actions using data for 2018 or 2019 purchases and installations:

- Electric Vehicles
  - All-Electric Vehicles
  - Plug-in Hybrid Electric Vehicle
  - Electric School Bus
  - Electric Transit Bus
- Electric Efficiency Measures—Efficiency Vermont Portfolio Average for 2019
- Cold-Climate Air Source Heat Pump (Minisplit)
  - Weatherization (Market Rate and Low Income)
- Renewable Generation
  - New Net-Metering Installation (5 kW and 150kW Examples)
  - New In-State Solar Qualified Under Tier II of Vermont's RES (4.9 MW Example)
- Advanced Wood Heating
  - Pellet Stove
  - Pellet Furnace
  - Pellet Boiler
- Heat Pump Water Heater (Representative Replacement of Existing Electric Resistance and Fossil Fuel Units)

Important Notes

- The model was completed with best available data, including values used in the state technical reference manuals for energy efficiency and Tier III measures.
- The input values used are a ***snapshot in time***, meaning they do not future changes in incentive levels or equipment costs. Electricity prices, fossil fuel prices, and the expected grid mix do change based on PSD and EIA forecasts.
- The model **does** include directly attributable economic costs to the participant and the utility, including the incentive cost.
- The model **does not** quantify health benefits, comfort, or economic impacts, such the number jobs created. These societal benefits are excluded because reliable estimates are not available for all measures, or because there is no single agreed value (such as societal cost of carbon).
- The model ***should be used to give a sense of scale and rough ordering of measures*** *and* ***should not be used for exact numbers***.

Model Results

Measure Cost Type	Measure	Lifetime Net Resource Cost	Lifetime Avoided CO_2 (Tons)	Net Cost per Ton of CO_2 Saved ($/ton)
Mixed	Electric Efficiency Portfolio	($61)	0.04	($1,429)
Incremental	Plug-in Hybrid Electric Vehicle	($3,761)	25	($148)
Incremental	Heat Pump Water Heater	($1,125)	8	($145)
Incremental	All-Electric Vehicle	($692)	42	($17)
Full	Residential Weatherization	$453	28	$16
Full	Wood Pellet Stove	$3,366	82	$41
Full	Heat Pump (Multizone)	$1,427	18	$80
Full	Heat Pump (Single Zone	$1,182	14	$88
Incremental	Wood Pellet Boiler/Furnace	$12,767	123	$104
Incremental	Electric Transit Bus	$236,812	711	$333
Full	Tier II Resource - 4.9 MW	$617,598	1,048	$589
Incremental	Electric School Bus	$194,388	189	$1,028
Full	Solar Net-metering, 150 kW	$72,633	22	$3,234
Full	Solar Net-metering, 5 kW	$6,980	0.75	$9,325

Note: Red text and parentheses indicate negative values. These negative net costs are measures with net benefits over their lifetimes.

Selected Assumptions for Summary Table	
Fossil Free Scenario for Electric Grid	Current/Expected
ICE Vehicle Comparison - MSRP	Mid-size Car
ICE Type - MPG	Car/SUV
EV Incentive Amount	$2,500
Electric Bus Incentive	$50,000
Cold Climate Heat Pump - Single Zone	12,000
Cold Climate Heat Pump - Multi Zone	18,000
Cold Climate Heat Pump Incentive	$500
Heat Pump Water Heater - Size	< 55 Gallon
Heat Pump Water Heater - Incentive	$500

About the Cost Effectiveness Test

When conducting cost-effectiveness analysis, there are several different perspectives that can be applied. Each perspective is designed to answer slightly different questions, such how taking a specific action provides a net benefit (or cost) to the individual participant, to other ratepayers, or to society at large. An overview of the tests is provided in the US EPA's National Action Plan for Energy Efficiency.

This model's approach is similar to a total resource cost test, which compares the program administrator and customer costs with overall resource savings. Unlike a total resource cost test, however, financial costs and benefits are calculated with a boundary drawn around Vermont; in other words, ratepayer benefits that accrue to the rest of New England are not included.

The test uses the quantifiable costs and benefits associated with a specific measure to analyze cost effectiveness. A result that shows benefits outweighing costs, i.e. a negative cost-benefit ratio, doesn't necessarily mean that the individual consumer will be better off or that a consumer will invest in that measure absent incentives as the benefits may not accrue back to the consumer. For example, the societal cost test for net metering includes an energy benefit for the utility, however, this is not likely to be a motivating factor for consumers. The model also estimates the program administrator test for each program or policy. This cost test demonstrates the cost per ton of carbon avoided given an assumed incentive level. For example, AEVs will be analyzed based on an incentive level plus an adder to estimate program administration costs which is then divided by the total tons of carbon avoided to demonstrate the cost per ton avoided for that incentive.
Incremental measure costs assume that an similar action will be implemented anyway, and the measure cost is the incremental cost. Examples include purchasing an EV instead of a new internal-combustion vehicle, or installing a pellet boiler instead of an oil boiler.) Full measure costs include the entire upfront cost assuming that no other action would be taken. Examples include adding a pellet stove or heat pump to a home without replacing the existing heating system.

The model first calculates the total carbon reduction associated with each measure over the assumed measure life. The specifics vary for each measure. As an example, for EVs the model calculates the average carbon emissions of the internal combustion engine vehicle that is displaced by a consumer purchasing an EV. Then, if necessary, the model calculates the total carbon emissions from the measure itself over the measure life and reduces the carbon reduction amount calculated in the first step by this amount. For all of the programs and policies in this model, with the exception of energy efficiency, the model does not account for free-ridership (those people who would have taken the particular action being incentivized regardless of the inventive) or spillover (actions not incentivized by a particular program or policy, but that were taken as a result of the program or policy existing). These two steps provide the total tons of carbon that are assumed to be reduced for each measure.

The model then calculates the readily quantifiable costs and benefits of each measure for each year of the measure life and performs a net-present value calculation to evaluate those figures in today's dollars. This provides the total cost (or benefit) that is then divided by the total tons of carbon avoided to arrive at cost ($) per ton of carbon avoided for each measure. Two specific measures were written up below to provide examples of the how the calculations work.

Methodology for Select Measures

Electric Vehicle Calculations
The calculations for electric vehicles start by estimating the amount of fossil fuels the vehicle is assumed to offset. This is accomplished by dividing annual miles traveled by the assumed efficiency of the vehicle. Then a carbon coefficient is applied to the amount of fossil fuel based on the fuel type of the vehicle being displaced in order to calculate the amount of carbon emission avoided. Next, the model calculates the emissions associated with the increased electricity consumption of the EV. This calculation divides the annual miles traveled by the electric efficiency of the vehicle to generate the electricity consumption (in number of MWh) per year. Then that number is reduced by the utilities' assumed fossil-

fuel-free percentage to reflect the effects of the RES. Finally, the remaining MWh are assigned the carbon content of the NEPOOL GIS residual mix.

Costs for the electric vehicles are calculated as the purchase price premium, or the difference between the upfront purchase price of an internal combustion vehicle and the electric equivalent. Additionally, operations and maintenance savings are quantified annually for both internal combustion vehicles as well as electric vehicles and a net-present value of the difference between the two offsets the upfront purchase price of the EVs.

Finally, the net cost (upfront purchase premium minus O&M savings) is divided by the lifetime carbon emissions avoided to arrive at the dollars per ton of carbon figure (for the societal cost test). For the program administrator cost test, the lifetime emissions avoided are divided into an assumed incentive level (marked up by 30% for administration costs which is meant to capture the overhead costs needed to deliver a program; examples include incentive processing, other staff time, etc.) to arrive at the dollars per ton of carbon figure.

Solar Calculations (Net Metering and Tier II Resources)

The solar section of the model starts by calculating the systems annual production, which is a function of the systems assumed nameplate capacity and the capacity factor. Once the annual production has been calculated, the model discounts the production by the distribution utilities' fossil fuel-free percentage and percentage to reflect the effects of the RES. Next, the remaining MWh are assigned the carbon content of the NEPOOL GIS residual mix to calculate the tons of carbon avoided figure.

The construction cost is calculated by multiplying the nameplate capacity by the assumed dollars-per-watt construction costs. To arrive at the full societal cost, the cost of integration and the intermittent nature of solar generation is added to the construction costs and then the costs are discounted by the benefits that the project provides. These benefits are energy, capacity, and avoided ancillary services. Energy is calculated as 95% of the around-the-clock annual price per MWh. Capacity benefits are calculated by forecasting FCM prices, applying a coincidence factor to recognize that solar production doesn't align with the regional system peak, and a 95% scalar applied to the coincidence factor to reflect the fact that as more solar is put onto the regional system, the peak will be pushed later into the day in coming years. This value is multiplied by the project's nameplate capacity as well as a reserve margin benefit (35% over the lifetime of the project).

REC benefits are calculated by multiplying the system's assumed annual output times a forecast of REC prices. Avoided ancillary services are quantified by assuming a value of $1/MWh and multiplying by the annual production. Net present value calculations are performed across all of these benefit streams prior to netting the costs described above. Finally, the net value of costs and benefits is divided by the amount of carbon emissions avoided in order to arrive at the dollars per ton of carbon avoided.

The program administrator cost test for the net metering facilities calculates the annual production of the system and what that system would have been compensated at for its production through the net metering program and, separately, at market rates. The net-present value of the difference between these two value streams is the assumed incentive paid to a net metering system over its lifetime.

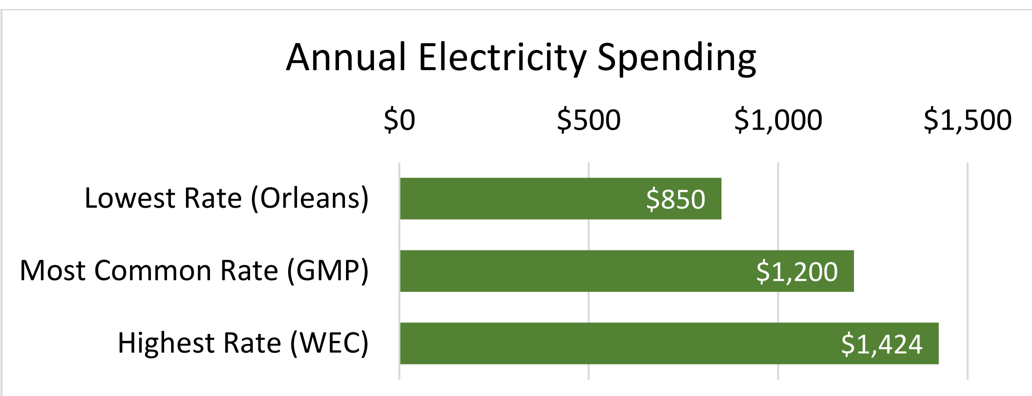
Appendix C - Household Energy Spending

The average Vermont household directly spends $4,000 to $5,000 on energy annually. This includes electricity, thermal fuels for space heating and water heating, and transportation fuels such as gasoline. Household energy spending is determined by equipment, fuel prices, and usage patterns. Some aspects, such as heating system type or vehicle style, are choices. Other aspects are not, such as the provision of electric service. (Transportation and heating increasingly use electricity as fuel, although the total effect is small at this time.) In considering typical Vermont households with differing electric rates, heating fuels, weatherization levels, and vehicle choices, annual energy spending can range from $3,000 to $6,000.

Electricity

Residential electric rates vary by distribution utility. The chart below compares annual electricity spending for a typical Vermont household at the blended residential electricity rates in three utility territories. While household characteristics (family size, appliance use, etc.) exert the greatest interest on electricity spending, electricity rates clearly impact energy spending.

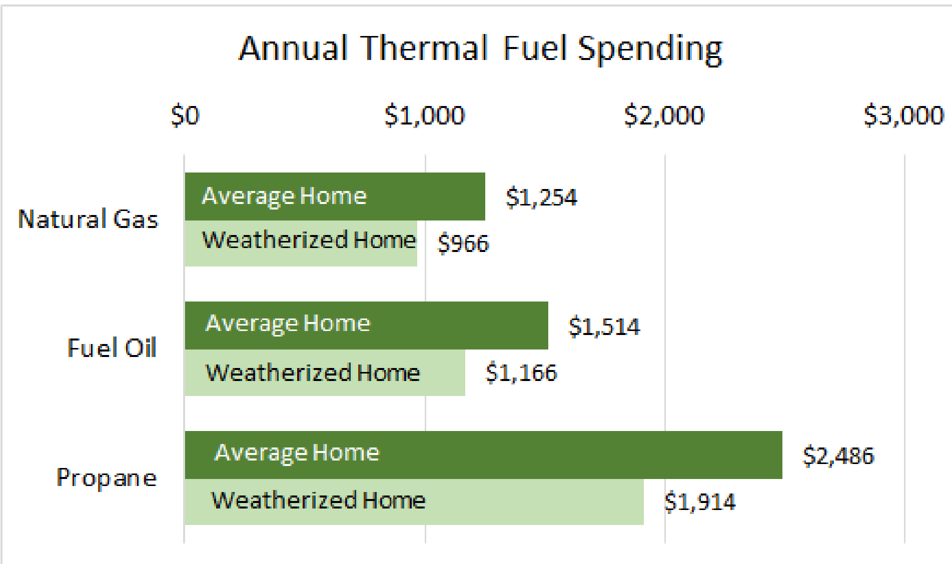
At present, Washington Electric Cooperative currently charges residential customers the highest rates. WEC employs a two-block rate, with a low-priced initial block and higher second block. It should be noted that—perhaps as a result of the high overall price of electricity—Washington Electric Cooperative customers on average use less electricity at home than Vermont residential customers overall. The Village of Orleans Electric Department offers the lowest residential rate, while Green Mountain Power serves the greatest number of residential customers.



Thermal Fuels

Thermal fuels are used for space heating, water heating, and—in some instances—cooking. Global and regional markets set prices for heating oil and propane. Natural gas prices are based on the North American gas market but customer rates are ultimately subject to approval by the Public Utility Commission.

The chart below compares these petroleum fuels for an average Vermont home and for a weatherized Vermont home that has implemented feasible cost-effective efficiency measures (reducing consumption by 23%). Note that wood heating is not included. While cordwood and wood pellets account for a quarter of Vermont's heating need, the variability in wood fuel delivery mechanisms (bagged pellets, bulk pellets, bulk delivery by the cord, etc.) and varying equipment heating efficiency makes wood ill-suited for this type of analysis. (There is no "average" wood heating system.) Recent data from New Hampshire suggests that delivered wood fuels have a price comparable to fuel oil.[61]



Transportation Fuels

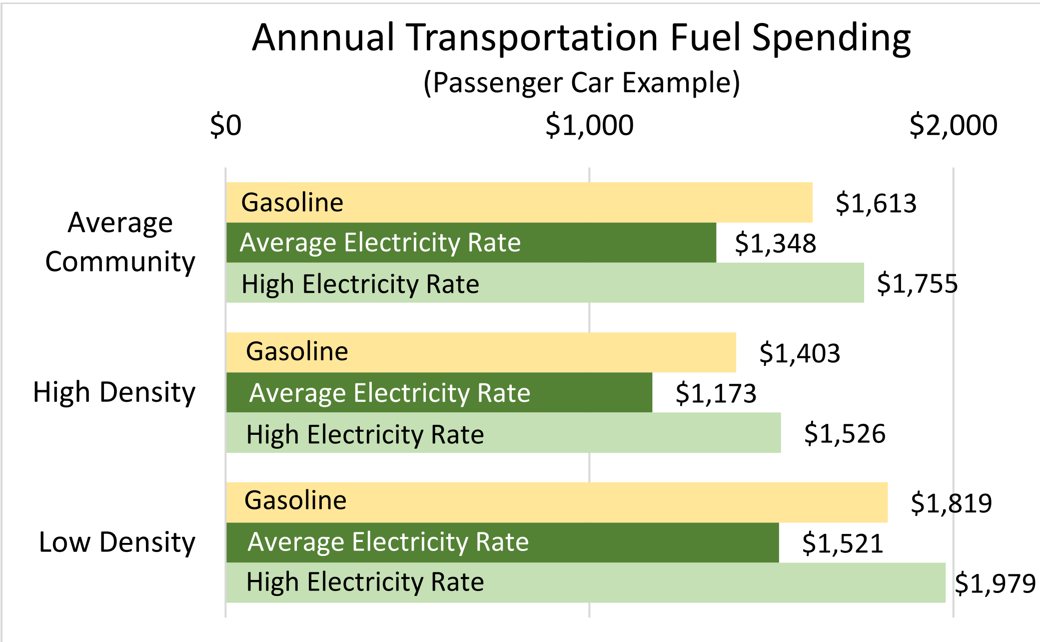
Household spending energy on transportation likely varies the widest among the three categories. Some Vermont households do not use a personal vehicle and rely on a combination of public transit, walking, and bicycling for daily life. Other households who do maintain a personal vehicle may use it sparingly. Notably, energy spending alone does not reflect additional vehicle costs such as depreciation and maintenance.

Fuel Price Equivalents ($/gallon)	
Regular Gasoline	$2.15
Avg. Electricity Rate	$1.80
Highest Electricity Rate	$2.34

Rather than reflecting the full range of households, the graph below shows energy spending based on three fuel prices (gasoline, the statewide average residential electric rate, and the highest residential electric rate) and three examples of household vehicle travel. The three examples consist of the statewide average for household travel, and example of a high-density community where vehicle travel is lower (Barre City), and an example of a low-density community where the annual miles traveled is higher (Bakersfield). *Household* vehicle miles traveled (VMT) is used, not per-capita VMT, in keeping with the household analysis for electricity and thermal fuels.

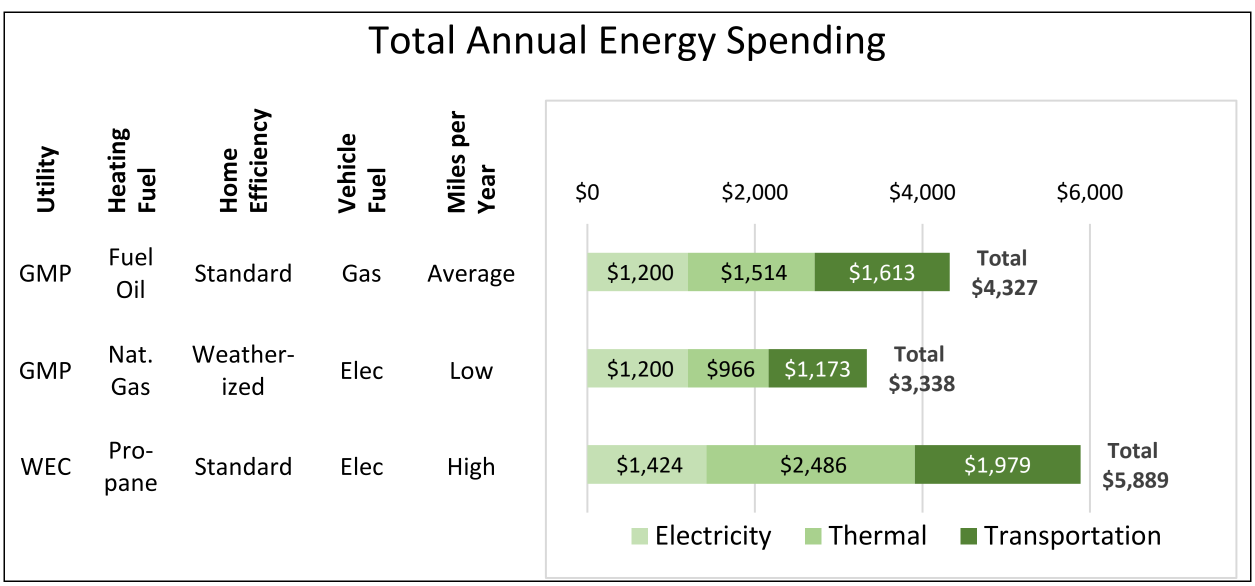
[61] See NH OSI, https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm.

The analysis assumes gasoline fuel economy of 30.8 miles per gallon (MPG) to compare sedan internal combustion engine vehicles with similar all-electric models. However, the actual fuel economy of Vermont's registered vehicles was 22.7 MPG in 2019. This means that actual energy spending on gasoline is greater than the car represented in the chart below due to the high prevalence of trucks and SUVs in Vermont's vehicle fleet.



Total Energy Spending

An archetypal Vermont household that is served by Green Mountain Power, heats with fuel oil, and drives gasoline passenger cars spends $4,327 annually on energy. The other example households below spend as little as $3,338 and as much as $5,889.



Appendix D – Renewable Energy Program Report

Report on Vermont Renewable Energy Programs

A Report to the Vermont General Assembly Prepared by the Department of Public Service

The General Assembly requires the Public Service Department (Department) to submit annual and biennial reports addressing renewable energy programs in the state (30 V.S. A. § 8005b(b), and § 8005b(c)). This report addresses each of these requirements including retail sales, requirements of the Renewable Energy Standard (RES), progress toward meeting RES targets, an assessment of historical and ongoing impacts of RES, implementation of the Standard Offer program, an assessment of energy efficiency, market conditions for renewable energy, and retail electric rates.

Contents

Introduction

In 2017, Vermont began implementation of the Renewable Energy Standard ("RES"), the first requirement in the state for electric utilities to provide renewable energy to their customers. Prior to this, programs were in place to support development of renewable resources, but the renewable attributes could be sold out of state, and therefore the energy from these resources did not provide renewable power for Vermonters. In addition, there are two current programs that predate the RES: The Standard Offer program and net metering. The Standard Offer program is an economic development program that began in 2009 and is scheduled to end in 2022, with a program capacity of 127.5 megawatts ("MW"); this program has undergone several changes since its implementation, with the most notable being an expansion of the initial 50 MW cap and a transition to a competitive procurement process. Net-metering has been available to Vermont electric customers for over 20 years; it started as an avenue for electric customers to reduce electric purchases from the utility with their own on-site generation, but over the years has transitioned to a mechanism that allows electric customers to invest in generation resources and reduce their electric bills. The output from projects built under these programs can be used for RES compliance, depending on the date the project was built.

Based on the experience to date, RES has been successful in reducing GHG emissions with limited cost implications. This is in part due to program design, and also the fact that the regional framework for tracking renewable attributes was put into place years ago by other New England states that had already adopted similar requirements. In addition to the power supply mandates, the RES requires electric utilities to reduce fossil fuel usage of their customers.

Pursuant to 30 V.S.A. § 8005b, the Department of Public Service ("Department") provides this report. This report addresses the following issues:

(1) The retail sales, in kilowatt-hours ("kWh"), of electricity in Vermont during the two preceding calendar years (§ 8005b(c)(1)).

(2) RES requirements for the two preceding calendar years (§ 8005b(c)(2)).

(3) A summary of the Renewable Energy Credit ("REC") retirements and energy transformation projects costs and benefits for the two preceding calendar years (§ 8005b(c)(3)).

(4) A summary of the Standard Offer program including the technology, number, capacity and average annual generation of the participating projects, and the prices paid. The report also shall identify the number of applications received, the number of participating plants under contract, and the number of participating plants in service (§ 8005b(c)(4)).

(5) An assessment of the energy efficiency and renewable energy markets and recommendations to the General Assembly regarding strategies that may be necessary to encourage the use of these resources to help meet upcoming supply requirements (§ 8005b(c)(5)).

(6) An assessment of whether Vermont retail electric rates are rising faster than inflation, and a comparison of Vermont's electric rates with electric rates in other New England states and in New York. If statewide average rates have risen faster than

inflation over the preceding two or more years, then additional assessments shall be included with any recommended statutory changes (§ 8005b(c)(6)).

(7)(A) Commencing with the report to be filed in 2019, an assessment of whether strict compliance with the requirements of sections 8004 and 8005 (RES) and section 8005a (Standard Offer) of this title:

(i) has caused one or more providers' rates to rise faster than the statewide average;

(ii) will cause retail rate increases particular to one or more providers; or

(iii) will impair the ability of one or more providers to meet the public's need for energy services in the manner set forth under subdivision 218c(a)(1) of this title (least-cost integrated planning).

(B) Based on this assessment, consideration of whether statutory changes should be made to grant providers additional flexibility in meeting requirements of sections 8004 and 8005 or section 8005a of this title (§ 8005b(c)(7)).

(8) Any recommendations for statutory change related to sections 8004, 8005, and 8005a of this title (§ 8005b(c)(8)).

Background

Renewable Energy Standard

Section 8 of Act 56 of 2015 directed the Public Utility Commission ("Commission") to implement a renewable energy standard, by means of "an order, to take effect on January 1, 2017." This requires Vermont's electric distribution utilities ("DUs") to retire a minimum quantity of renewable energy credits ("RECs") or similar attributes, and to achieve fossil-fuel savings from energy transformation projects.[62] The structure of the RES is divided into three tiers.

Tier I requires DUs to retire qualified RECs or attributes from any renewable resource capable of delivering energy into New England to cover at least 55% of their annual retail electric sales starting in 2017. A REC is the renewable attribute associated with a megawatt-hour ("MWh") of generation from a qualified renewable resource. The Tier I obligation 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 I 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 and thermal energy or geothermal resources for the long-term benefit of Vermont consumers."[63]

Tier II requires DUs to retire qualified RECs equivalent to 1% of their annual retail sales starting in 2017. Tier II-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 II requirement increases by three-fifths of a percent each year, up to 10% in 2032. Like Tier I, a utility can make an ACP in lieu of retiring Tier II RECs. Pursuant to Section 8005(a)(1)(C), Tier II resources

[62] 30 V.S.A. § 8005(b).
[63] 30 V.S.A. § 8015(c).

also count towards a DU's Tier I requirement. Additionally, to the extent that a DU is 100% renewable as of 2018, the DU is not required to meet the annual requirements set forth in Tier II but is required to accept net-metering systems and retire the associated RECs.[64] [65]

Some existing Vermont renewable programs such as net-metering and Standard Offer help utilities achieve Tier II compliance. Specifically, any net-metering[66] and Standard Offer projects commissioned after June 30, 2015 may qualify as Vermont Tier II resources. The Department estimates that each year 25-27 MW of new distributed generation will be needed to meet Tier II, assuming that Tier II continues to be met primarily with solar resources. Given the limited eligibility criteria for Tier II there is not a liquid market for these RECs and the necessary Tier II RECs have come from net-metering, Standard Offer, and resources owned by, or under contract to, utilities. To date, projects associated with existing programs have provided sufficient RECs for Vermont utilities to meet their RES requirements. As RES requirements increase and the Standard Offer program ends, there will be a need for additional Tier II resources. Given the limited eligibility for Tier II projects and lack of a market for Tier 2-eligible RECs, most DUs have chosen to over-procure Tier II resources to avoid paying the ACP. This compares with the market for Tier 1 RECs or for many of the other categories of renewable requirements established by other states.

The implementation of REC retirements for RES Tier I and Tier II 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 the 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 which required DUs to enter into stably priced long-term contracts, but did not require utilities to serve their load with renewable energy or to retire RECs.[67] The resources built or contracted for through SPEED continue to be in Vermont's power supply mix, and although many do not provide RECs for RES compliance, Vermonters are still paying for the energy and capacity procured under this program.

The REC markets in New England are all related to and driven by state renewable policies and eligibility criteria. "Existing" REC markets (e.g., Vermont Tier I, and Class II or "existing" in other states) are intended to provide incentives to existing resources to remain operational. "New" REC markets (e.g., Vermont Tier II, and regional Class I or "new" in other states) are designed to stimulate renewable development and provide a greater incentive than existing RECs. Vermont Tier I resources include any

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[64] 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).

[65] 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.

[66] Net-metering customers elect whether to transfer the RECs to the utility in exchange for a higher compensation rate. The vast majority of customers choose to transfer the RECs to the utility. However, prior to the PUC's change to the net metering rule, there was no provisions regarding the RECs from these facilities and therefore net metering facilities constructed prior to July 1, 2017, are not counted toward Vermont's renewable requirements.

[67] The use of RECs to track renewability is the generally accepted standard across the country.

renewable generator in the region and imports from neighboring control areas (e.g., Hydro Quebec – "HQ" – and New York Power Authority – "NYPA" – hydro). Vermont Tier I RECs are generally consistent with regional Class II or "existing" RECs in neighboring states, and in their short history, Tier I RECs have traded at similar prices to regional Class II RECs. Since the implementation of renewable standards in the region, there has been excess supply of these types of resources in the region, resulting in prices around $1/REC. In the region, regional Class I RECs have unique eligibility criteria by state, but generally, new renewable resources qualify, regardless of size, except in Vermont. Vermont Tier II, however, has a much narrower eligibility criteria than other states, and a resource that qualifies as regional Class I in neighboring states will not necessarily qualify as Vermont Tier II.

When there is sufficient supply of Tier II RECs, it is expected that Tier II and regional Class I RECs will trade at similar prices. However, if there is a shortage of Tier II RECs, then Vermont Tier II will trade at a premium to regional Class I in other states. Many Vermont utilities have resources in their portfolio that qualify as regional Class I (high-priced) and Vermont Tier I (low-priced), but not Vermont Tier II, resulting in the out-of-state sale of regional Class I RECs from Vermont resources (e.g., McNeil biomass, Kingdom Community Wind, pre-July 2015 Standard Offer projects, etc.) and the purchase of lower-priced Vermont Tier I RECs from out of state.

Act 56 also created Tier III, which requires DUs to achieve fossil-fuel savings from energy transformation projects or retire additional Tier II RECs. For Tier III, the RES requires savings equivalent to 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 III obligation. 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 III requirements are additional to the Tier I requirements and Tier III compliance can also be met through the retirement of Tier II RECs or payment of an ACP.

To date, Tier III measures have focused on electrification measures—both custom and programmatic. In 2019, almost half of Tier III requirements were met with heat pumps and another 10% with electric vehicles. Utilities have reduced fossil fuel usage through various means including line extensions,[68] weatherization, industrial compressed natural gas burners and electric boilers.

Standard-Offer Program

The Standard Offer program, established in 2009, was designed to provide a financing mechanism for small-scale renewable energy projects of 2.2 MW or less by offering renewable resources long-term fixed price contracts with the state, through the Standard Offer program administrator (currently VEPP, Inc.). This requirement was imposed before Tier II and before the above-retail rate solar adder for net metering, when there was a limited amount of distributed renewable generation in Vermont.

The Standard Offer program initially had a 50 MW program capacity that was expanded to 127.5 MW in 2012. The 2012 statutory changes set an annual schedule that require the PUC to issue standard offers

[68] Many of these line extensions are related to providing sufficient electric service for a sugaring or sawmill operation to switch away from diesel generators.

for 5 MW in each of the first three years, 7.5 MW each year for 2016-2018, and 10 MW annually in 2019-2022 until the cap of 127.5 MW is reached.[69] Prior to 2012, there was a centralized procurement process and an administratively determined fixed price for all resources within a particular technology category. This approach resulted in rapid deployment of solar resources at a significant cost, with early solar projects receiving $0.30/kWh. In 2012, the program was modified to allow for a market mechanism to set the contract price. Contracts are now awarded to generators annually through a Request for Proposal ("RFP") process which includes a price cap for each technology type including solar, wind, biomass, landfill gas, and food-waste methane digesters, and hydroelectric facilities of up to 2.2 MW.[70]

Under the program, the Standard Offer facilitator is required to enter into fixed price, long-term contracts for the output of awarded projects. The costs associated with the program, as well as the energy, capacity and RECs from the projects, are allocated to each DU based on their pro-rata share of load.[71] Vermont utilities may use RECs from Standard Offer projects commissioned after July 1, 2015 to satisfy Tier II of the RES. RECs from Standard Offer projects built before this date may be used to satisfy Tier I. However, RECs from Standard Offer projects commissioned prior to July 1, 2015 are generally qualified as regional Class I resources in neighboring states. As described earlier, regional Class I prices are typically similar to Vermont Tier II and therefore significantly more valuable than Vermont Tier I. Therefore, those RECs would most likely be sold out of state as regional Class I RECs rather than used for Tier I compliance in Vermont.

Ryegate

Ryegate is a 20 MW biomass (wood-fired) generator that qualifies for Vermont's Baseload Renewable Energy Standard. Under 30 V.S.A. § 8009, utilities must purchase their pro rata share of the output from Ryegate under a 10-year contract administered by VEPP, Inc. The current contract expires November 1, 2022. Given the size and age of the plant, RECs generated by Ryegate are not eligible for Tier 2 and are sold outside of Vermont.

Renewable Energy Standard

RES Performance to Date

Pursuant to the Commission's *Order Implementing the Renewable Energy Standard*, issued in Docket 8550 on June 28, 2016, Vermont utilities were required to submit annual RES compliance filings by August 31 each year demonstrating compliance for the previous calendar year. On February 20, 2019, the Commission issued an order in Docket 19-0716-INV concluding that all Vermont utilities met their 2018 RES requirements. On December 17, 2020, the Commission issued an order in Docket 20-0644-INV approving 2019 RES compliance for all utilities. In its review of the 2019 compliance filings, the

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[69] Pursuant to 30 V.S.A. § 9005a(c)(1)(A), "The amount of the annual increase shall be five MW for the three years commencing April 1, 2013, 7.5 MW for the three years commencing April 1, 2016, and 10 MW commencing April 1, 2019."

[70] Standard Offer rates are also available for farm methane digesters. These projects do not count toward the 127.5 MW programmatic cap.

[71] A utility may seek exemption from the standard-offer program if during the previous year it had renewable energy, through either ownership or contracts, that was not less than its amount of retail sales.

Department found that utilities demonstrated compliance with Tiers I and II of the RES by retiring RECs in the NEPOOL Generator Information System ("NEPOOL GIS"), which closed its trading period for 2019 on June 15, 2020. Additionally, utilities submitted Tier III compliance claims to the Department on March 15; the Department evaluated Tier III performance and presented those findings in a Tier III Report filed on July 1, 2020. Table 1, below summarizes Tier I and Tier II REC retirements and Tier III savings claims by utility for the previous two years.

2018 & 2019 REC RETIREMENTS AS A PERCENT OF RETAIL SALES

	2018			2019		
Utility	Tier I[72]	Tier II[73]	Tier III	Tier I	Tier II	Tier III
Barton	55%	1.6%	0.0%	55%	2.2%	2.0%
Burlington	103%	0.0%	2.7%	103%	0.0%	3.3%
Enosburg Falls	55%	1.6%	0.0%	55%	2.2%	2.0%
GMP	60%	1.6%	2.7%	64%	2.2%	3.3%
Hardwick	55%	1.6%	0.0%	55%	2.2%	2.0%
Hyde Park	55%	1.6%	0.0%	55%	2.2%	2.0%
Jacksonville	55%	1.6%	0.0%	55%	2.2%	2.0%
Johnson	55%	1.6%	0.0%	55%	2.2%	2.0%
Ludlow	55%	1.6%	0.0%	55%	2.2%	2.0%
Lyndonville	55%	1.6%	0.0%	55%	2.2%	2.0%
Morrisville	55%	1.6%	0.0%	55%	2.2%	2.0%
Northfield	55%	1.6%	0.0%	55%	2.2%	2.0%
Orleans	55%	1.6%	0.0%	55%	2.2%	2.0%
Stowe	55%	1.6%	0.0%	55%	2.2%	2.0%
Swanton	100%	0.1%	0.0%	100%	0.2%	2.0%
VEC	55%	1.6%	2.7%	55%	2.2%	3.3%
WEC	100%	1.6%	2.7%	100%	0.0%	3.2%
Vermont State Total	**63%**	**1.8%**	**2.5%**	**66%**	**2.0%**	**1.1%**

Table 1: 2018 & 2019 Tier I and Tier II REC retirements and Tier III savings claims

RES allows for the banking (up to 3 years) of excess RECs to then be used for compliance in future years. In 2019, several utilities acquired RECs in excess of their RES requirements, with the intention of using those RECs for compliance in one of the next three years. REC retirements shown in Table 1 reflect only those RECs being used in 2018 and 2019, and do not report on RECs being banked for future years.

Retail sales for Vermont utilities have been relatively flat to decreasing in recent years, somewhat offsetting increases to RES requirements. Statewide electric sales declined by 2.1% from 2018 to 2019

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[72] Tier I percentages reflect total renewable percent, inclusive of Tier II (i.e. in 2018, DUs served 63% of the retail load with renewable resources). Several utilities elected to retire RECs in excess of their statutory requirement.
[73] If a DU demonstrates that it is 100% renewable through Tier I REC retirements, then the DU is not required to meet the annual requirements set forth in Tier II but is required to accept net-metering systems and retire the associated RECs per Section 5.127(B)(1) of Rule 5.100 and 30 V.S.A. § 8010(c)(1)(H)(ii).

and have been on a declining trend for the past 10 years due to energy efficiency measures and net-metering. In 2018 and 2019, Vermont DUs were required to retire qualified Tier I RECs or attributes equivalent to 55% of their retail sales, including Tier II RECs. In 2018, the Tier II requirement was 1.6% and in 2019 it was 2.2%. Retail sales and annual RES requirements by tier for calendar years 2018 and 2019, the two most recent years available, are presented in Table 2 and Table 3 below.

VERMONT ELECTRIC RETAIL SALES AND RES OBLIGATIONS: 2018

UTILITY	Retail Sales (MWh)	Tier I Obligation	Tier II Obligation	Tier III Obligation
Barton Village Inc	13,646	7,505	218	n/a
Burlington Electric Dept	333,764	183,570	5,340	9,012
Enosburg Falls Village	26,848	14,766	430	n/a
Green Mountain Power	4,222,266	2,322,246	67,556	114,001
Hardwick Village	33,546	18,450	537	n/a
Hyde Park Village	11,774	6,476	188	n/a
Jacksonville Village	4,987	2,743	80	n/a
Johnson Village	12,509	6,880	200	n/a
Ludlow Village	54,579	30,019	873	n/a
Lyndonville Village	58,533	32,193	937	n/a
Morrisville Village	45,789	25,184	733	n/a
Northfield Electric Dept.	28,217	15,520	451	n/a
Orleans village Inc	13,690	7,530	219	n/a
Stowe Village	75,165	41,341	1,203	n/a
Swanton Village Electric	54,620	30,041	874	n/a
Vermont Electric Coop	459,995	252,997	7,360	12,420
Washington Electric Coop	70,494	38,772	1,128	1,903
TOTAL	**5,520,422**	**3,036,232**	**88,327**	**137,336**

Table 2: 2018 Vermont electric retail sales and RES obligations reflect retail sales as reported by the Vermont electric distribution utilities to the Public Service Department.

VERMONT ELECTRIC RETAIL SALES AND RES OBLIGATIONS: 2019

UTILITY	Retail Sales (MWh)	Tier I Obligation	Tier II Obligation	Tier III Obligation
Barton Village Inc	13,565	7,461	298	271
Burlington Electric Dept	322,601	177,430	7,097	10,753
Enosburg Falls Village	26,262	14,444	578	525
Green Mountain Power	4,128,426	2,270,634	90,825	137,613
Hardwick Village	33,785	18,582	743	676
Hyde Park Village	11,998	6,599	264	240
Jacksonville Village	4,906	2,699	108	98
Johnson Village	12,583	6,920	277	252
Ludlow Village	55,340	30,437	1,217	1,107
Lyndonville Village	61,855	34,020	1,361	1,237

Morrisville Village	45,180	24,849	994	904
Northfield Electric Dept.	28,824	15,853	634	576
Orleans village Inc	12,688	6,978	279	254
Stowe Village	74,798	41,139	1,646	1,496
Swanton Village Electric	53,139	29,226	1,169	1,063
Vermont Electric Coop	451,381	248,259	9,930	15,046
Washington Electric Coop	68,358	37,597	1,504	2,279
TOTAL	5,405,687	2,973,128	118,925	174,389

Table 3: Vermont electric retail sales and RES obligations reflect retail sales as reported by the Vermont electric distribution utilities to the Public Service Department.

In 2019, Tier I was met with RECs from a variety of resources including utility-owned hydro facilities, long-term HQ bundled purchases, regional hydro REC-only purchases, and unbundled attribute-only HQ purchases, among others. In 2019, Tier II was satisfied with continued growth in net-metering, Standard Offer projects, and in-state solar, both utility- and merchant-owned. Tier I and Tier II REC retirements for 2019 are summarized in Figure 1.

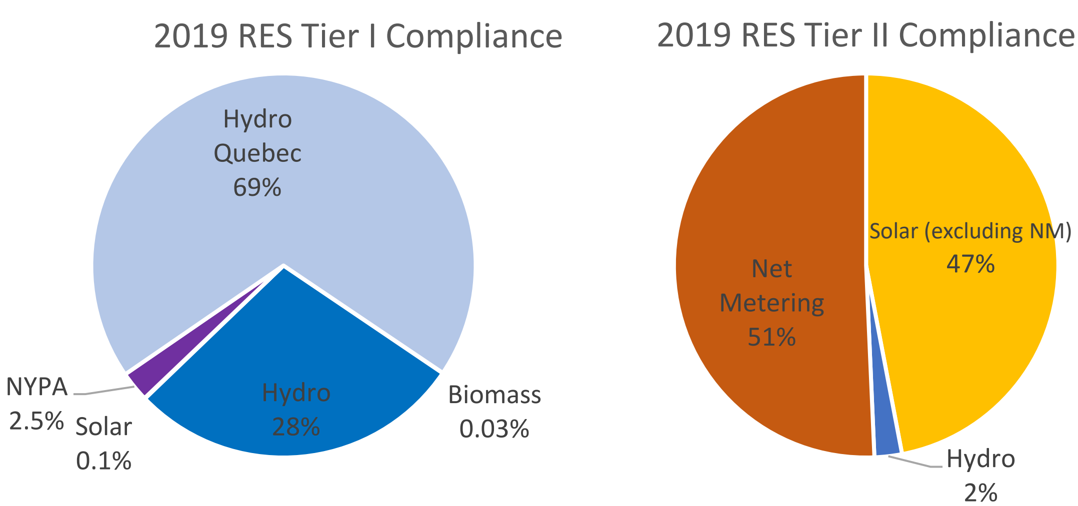

Figure 27: 2019 Tier I and Tier II REC retirements

Tier III obligations were met with a combination of approved programs, custom projects, and Tier II RECs. Programs to promote the adoption of cold-climate heat pumps, electric vehicles, electric vehicle charging stations, heat pump water heaters, weatherization, and wood heat were all utilized. Additionally, several utilities developed custom projects, primarily for Commercial and Industrial customers, to meet their Tier III obligations which were both cost effective and delivered significant fossil-fuel savings, while other DUs met portions of their Tier III obligation with the retirement of Tier II RECs. Custom projects included: extending electric lines to operations that were previously dependent on diesel or gasoline generators; electric boilers; and other custom heating and cooling projects. A breakdown of measures that were used to meet Tier III requirements can be seen in Figure 2.

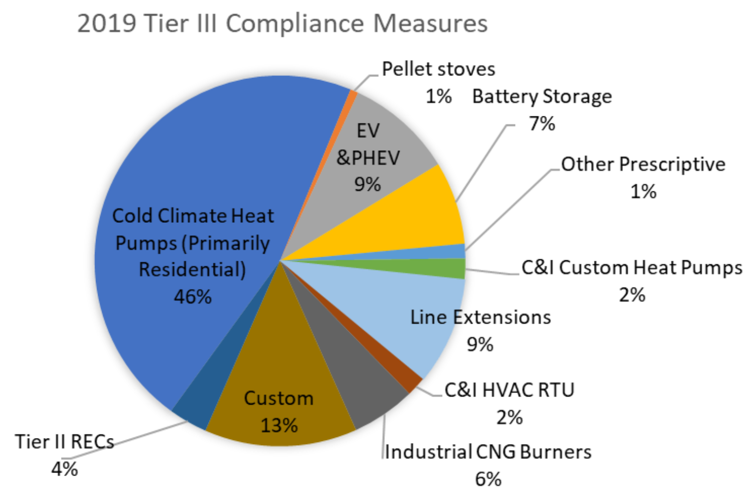

Figure 28: 2019 Tier III Measures

Key metrics summarizing 2019 RES performance are included in the table below:

2019 RES Performance	REC Retirements		Compliance Cost
Tier I	3,564,110	RECs	$1,240,000
Tier II[74]	118,262	RECs	$4,650,000
Tier III	176,839	Mwhe[75]	$6,030,000
Total Cost of Compliance			$11,920,000
Retail Sales	5,405,687	MWh	
Rate Impact of RES Compliance[76]	1.4%		
CO2 Reduction from RES[77]	558,694	tons of CO2	
Vermont Emissions Profile	47	lbs per MWh	

Table 4: 2019 RES Performance

Compliance costs for 2019 were estimated to be about $11.9 million, compared to maximum potential costs of $48 million.[78] For context, gross revenues for all DUs in 2019 was $850 million. Total Carbon Dioxide ("CO_2") emissions in the electric sector were reduced by approximately 842,000 tons from 2016

[74] The 118,262 2019 Tier II REC retirements include 8,998 RECs retired for Tier III compliance.
[75] MWhe is the nomenclature for MWh equivalent for Tier III savings claims.
[76] The rate impact is based on the 2019 total gross receipts of $849,972,131.
[77] Emissions reductions for 2019 are based on the change in Vermont's power supply portfolio from renewables, which increased from 35% in 2016 to 66% in 2019, resulting in a reduction in the amount of energy from the residual mix, which in 2019 had an emissions factor of 723 lbs/MWh. Emission reductions associated with Tier III measures are also included. Tier III credits are based on lifetime savings. Based on average 13-year life of Tier III measures and applied to all installed Tier III measures in the first 3 years of RES. The total annual MWh savings was calculated to be 30,828 MWh resulting in the equivalent of 11,035 tons of CO2 avoided in 2019.
[78] Maximum potential costs reflect what the costs would have been if ACP was paid to meet all 2019 RES requirements.

emissions.[79] This shift to more renewables combined with an increased share from nuclear energy and an overall cleaner system in New England brings Vermont's average emissions rate down to 47 pounds of CO_2 per MWh compared to the regional New England average of 658 pounds per MWh in 2018.[80]

After three years of experience, it is still in the early stages to draw conclusions about the overall impacts of the program. To date, the direct economic impacts of RES have been modest, but because a significant amount of Tier II has been met with net-metering projects, RES is not being met at the lowest possible cost. Utility programs that have incentivized electrification have resulted in customer savings and fuel price stability. The Department will continue to monitor each of these areas as the program matures.

Projections of Future Program Performance

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 can model a range of assumptions regarding energy and REC price, net-metering deployment, technologies used to meet Tier III requirements, and the impact of new Tier III load on peaks.[81] 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 in *Projected Program Impacts.*

The main outputs of the RES model, for any given set of assumptions, is a calculation of the total incremental utility expenditure required, the resulting rate impact of compliance with the RES requirements, and the cumulative greenhouse gas ("GHG") emission reductions over the next ten years. The compliance cost can be mapped to each tier of RES. The costs of Tier I and Tier II compliance are determined primarily by the amount that utilities are assumed to pay to acquire RECs from eligible renewable generation resources. The cost of Tier III 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. Reduced GHG emissions reported are a result of Tiers I, II and III, and do not include other changes in Vermont's energy portfolio.[82]

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 2021 VELCO Long-Range Transmission Plan ("LRTP") baseline load forecast

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[79] In addition to CO2 reductions directly resulting from RES, Vermont's electric mix was 28% nuclear in 2019 compared to 12% in 2016. This increase may be a result of utilities being incentivized to decrease their share of fossil fuel energy for Tier III purposes, but for purposes of this report, the reduction in emissions from increased nuclear has not been categorized as being attributable to RES, except as accounted for in the Tier III credit calculation. Additionally, the region's electric mix has been getting cleaner, further contributing to lower emissions, though not directly tied to RES.

[80] https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf.

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

[82] From 2017 to 2019, Vermont's share of energy from nuclear generators increased from 13.5% to 27%, resulting in a significant decrease in GHG emissions. These reduced emissions are not included in the reported GHG emission reductions in this report.

developed by Itron, which includes existing energy efficiency, net metering, and load from electrification measures through 2019.[83] The baseline forecast was developed by estimating customer class sales and end-use energy requirements.[84]

To forecast net-metering installations, Itron uses a customer payback model. The result is high net-metering deployment rates in the near-term that slow in the long-term as the market becomes saturated and net-metering compensation is reduced. The Department considers Itron's forecast to be a reasonable base case, but likely high in the near term given the recent reduction in compensation resulting from the net-metering biennial review[85] and the impacts of COVID-19 on 2020 deployment. Alternative scenarios reflecting higher and lower net-metering deployment have also been developed and are shown in Figure 3. In the ongoing net-metering rulemaking, Docket 19-0855-RULE, the Department proposed altering the net-metering compensation structure to significantly reduce the compensation for excess generation exported to the grid, to better align the compensation with the value it provides and the system installation costs, as well as to minimize the program's cross-subsidy.[86] If the compensation rates are adjusted in line with the Department's straw proposal, the pace of net-metering deployment will likely decrease, making the mid net-metering scenario the most probable.

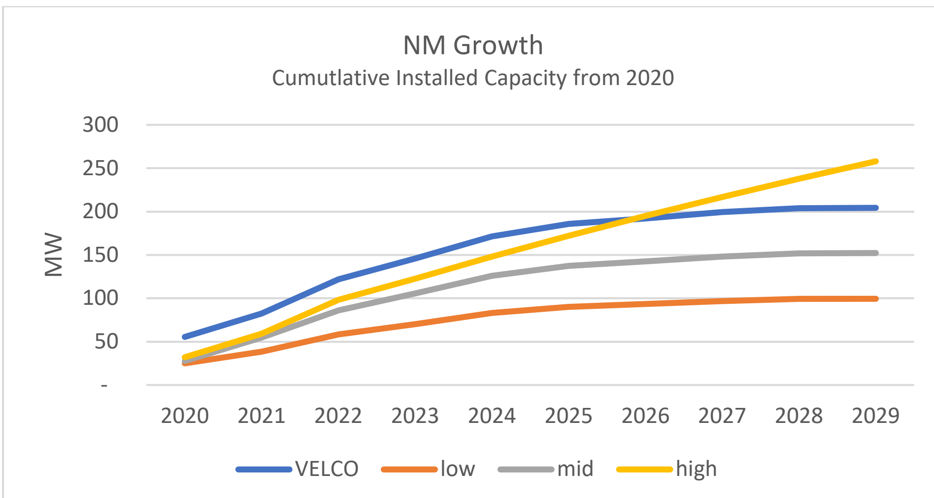

Figure 29: Net-metering growth scenarios

Additional load from Tier III measures is dependent on the assumptions regarding the technologies deployed to achieve Tier III fossil fuel reductions. For example, a future with weatherization as the primary tool used to meet Tier III 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").

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[83] The report containing the forecast has not been published, as of the date of this report. The report was prepared by Itron, a consultant to VELCO, for the Vermont System Planning Committee. Further information can be found at: https://www.vermontspc.com/.

[84] *Id.*

[85] See Case No. 20-0097-INV, Order of 11/12/2020.

[86] See Case No 19-0855-RULE for additional details.

Based on the forecasted loads, Tier I, II and III requirements forecasts follow. Figure 4 shows Vermont's projected mid-case retail sales including additional load from Tier III, and Tier I and II RES requirements through for the 10-year projection period.

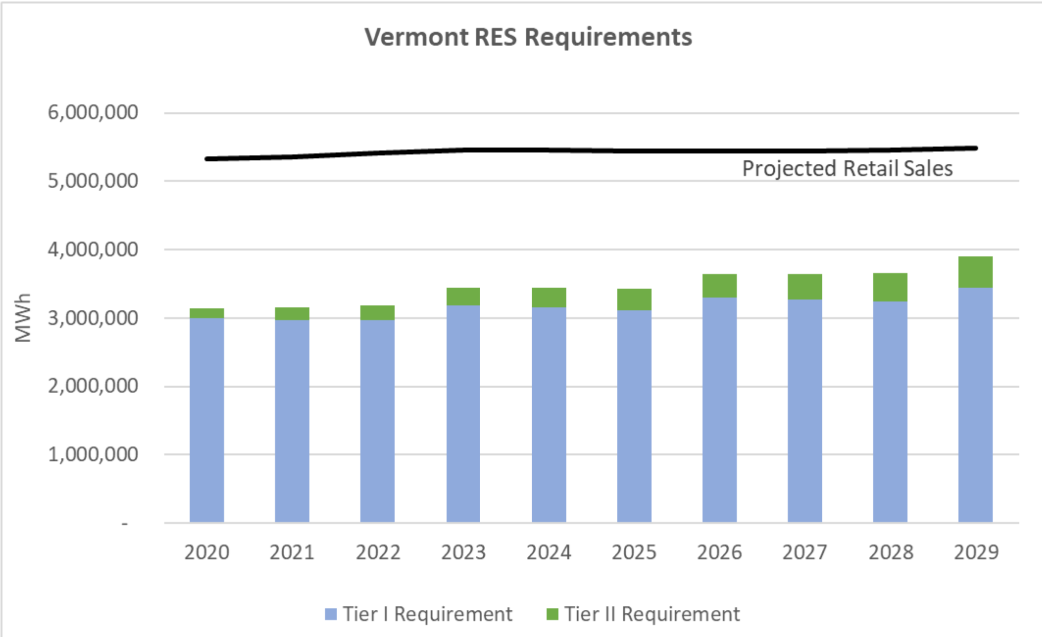

Figure 30: Projected retail sales and RES requirements

Tier I and Tier II Compliance Costs

Utilities must demonstrate Tier I and Tier II compliance with the retirement of qualified RECs. Absent sufficient RECs, an ACP must be paid to the CEDF. The RES Model makes assumptions about the price utilities will pay to procure RECs to estimate the cost of compliance. For each MWh of generation from qualified renewable resources, a REC is also created. The Department expects Vermont utilities to have sufficient RECs or attributes to meet their Tier I and Tier II requirements from a combination of:

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.

If a utility does not have sufficient RECs to cover its obligation, in the near term, the Department expects RECs will be available for purchase at prices lower than the ACP and consistent with premium RECs in other New England states.

In order to understand Vermont REC price forecasts, it is important to first understand the relationships among the different regional REC markets. Vermont Tier I RECs are generally equivalent to regional Class II or existing RECs in neighboring states, with the exception that imports from Quebec and New

York are considered renewable under Vermont law but not in neighboring states.[87] It follows that Vermont Tier I prices tend to be very similar to regional Class II prices in neighboring states. Vermont Tier II resources are a small subset of regional Class I or premium resources in other states, so when there is sufficient Tier II supply in Vermont, excess RECs will be sold as regional Class I to neighboring states, which results in Tier II prices that are very similar to regional Class I prices. However, if a shortage of Vermont Tier II resources develops, then prices will diverge with Tier II prices approaching the ACP while regional Class I prices would trade at a lower market price. More details on the Renewable Energy Markets outlook can be found in the Renewable Energy Markets Assessment section of this appendix.

REC markets provide the opportunity to claim renewability 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 I ACP was $10.40/REC and Tiers II and III were $62.42/REC in 2019; each will escalate annually with the Consumer Price Index. The RES Model includes three REC price forecasts that are intended to capture the market's supply-side uncertainty.

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, and the RPS requirements have been below available supply. The demand for RECs is created by state policy, and with a push for cleaner energy and reduced emissions in the region, other states are beginning to allow hydro imports to be used for clean energy requirements. This would increase demand for these RECs and result in higher prices. In recent years, Tier I RECs have traded around $1/REC, and are expected to remain at that level absent significant changes in demand for these resources in neighboring states.[88] Since July 2020 both New York[89] and Massachusetts[90] have modified their Clean Energy Standards (CES) to allow existing hydroelectric and nuclear generation facilities to meet clean energy mandates. In Massachusetts, the "CES-E" requires retail electric providers to procure a certain percentage of their retail sales from existing clean generation units[91] to help retain the contribution of these resources to the state's clean electric supply and meet low carbon objectives. Such modifications increasingly recognize the value of such resources to reduce carbon emissions in the region.

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[87] Clean energy standards in neighboring states are gaining traction and may soon allow for the use of these attributes. Massachusetts and New York recently modified their standards to allow for them.

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

[89] State of New York Public Service Commission, Case 15-E-0302 *Order Adopting Modifications to the Clean Energy Standard, Oct. 15, 2020.* https://www.nyserda.ny.gov/-/media/Files/Programs/Clean-Energy-Standard/2020/October-15-Order-Adopting-Modifications-to-the-Clean-Energy-Standard.pdf.

[90] *Final Amendments to 310 CMR 7.75.* Available at: https://www.mass.gov/doc/310-cmr-775-clean-energy-standard-amendments-july-2020/download.

[91] *Id.* Defines "Clean Existing Generation Units" as "A nuclear or hydroelectric generation unit that: (a) is located in Massachusetts, or in a jurisdiction that exported at least 4,000,000 MWh of electricity to Massachusetts in at least two years from 2001 through 2016, on a net annual basis, as reflected in the state greenhouse gas emissions inventories published annually by the Department; (b) has a nameplate capacity greater than 30 megawatts; and, (c) commenced commercial operation before January 1, 2011."

The Department expects utilities will be able to meet most of their Tier I obligations in the near term 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 Tier I base case assumes an average price of around $2.60/REC, with prices starting at $1/REC in 2020, increasing by 20% annually. The low case remains flat at $1/REC, and the high case averages $5.50/REC for 10 years.

Tier II 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 II REC supply going forward and could result in Vermont Tier II 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 II RECs. In the near term, Tier II obligations are expected to be met mostly with net-metering[92] and Standard Offer RECs, and the balance will likely trade at prices very similar to Massachusetts and Connecticut Class I markets. Looking further out, as RES requirements increase, additional in-state resources will be needed. As siting becomes more difficult, project costs may increase, which may lead to price separation between Vermont and other states. The Tier II base-case price forecast assumes an average price of $31/REC for Tier II RECs. The low-case averages $18/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 ignores banking and assumes that excess RECs in a given year will be sold at market prices to offset total compliance costs. Given the current robust Tier II availability, this is a reasonable assumption because utilities will sell excess RECs in the current year with the expectation of acquiring RECs in future years at a lower price.

In the RES model, total compliance costs for Tiers I and II 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 relevant statutory percentage to the annual retail sales forecast. Much of Vermont's Tier I obligation will be satisfied with RECs from existing long-term purchases from HQ and the NYPA Niagara Project[93] that come at no additional cost. The forecasted Tier I REC price is then applied to the balance of the obligation.[94] A similar method was applied to Tier II costs, with expected RECs from net-metering being assigned the REC adjustor spread, Standard Offer RECs assigned a $25/REC price,[95] and the balance (purchases or sales) assigned Tier II price forecast. Assuming all else equal, when the load forecast is higher, it follows that the obligations are higher, and therefore Tier I and II compliance costs will also be higher. The factors that most significantly impact obligations and costs are REC prices, net-

[92] 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). The cost of net-metering RECs is substantially higher than the cost of Tier II RECs from alternative sources. In 2019, utilities reported paying $40 million more than the market value for net-metering generation.
[93] The Niagara contract expires September 1, 2025. Vermont, along with other Neighboring States, is seeking to renew the contract.
[94] Tier I 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.
[95] This represents the estimated imputed price between the wholesale energy and capacity value and the PPA price paid to the generator.

metering deployment, and the extent to which utilities comply with Tier III obligations with measures that increase electric load.

The RES model projects the cost of Vermont utilities meeting RES requirements. However, in the three years of experience, Vermont utilities have exceeded RES requirements. Three utilities have demonstrated 100% renewability with the retirement of Tier I RECs, resulting in exemption from Tier II requirements, and one utility has elected to exceed Tier I requirements. The retirement of excess Tier I RECs has come at a very low cost, to date. These deviations from explicit RES requirements are not captured in the model.

Effect of Net-Metering on Obligations and Costs

Net-metering is a financial arrangement whereby a participating customer provides the financing for the development of a renewable resource – almost always solar – in return for the ability to use generation to help offset that customer's bill. Net-metering reduces the volume of electricity that utilities would otherwise sell to ratepayers. Larger volumes of generation from net-metering results in lower load and lower RES obligations, but also higher power supply costs, lower retail sales revenues, and more RECs from high-priced net-metering projects. Vermont utilities may not sell RECs associated with net-metering generation, which effectively makes net-metering a carve-out for Tier II. In other words, Tier II requirements are first met with net-metering RECs, and the remaining requirement is met with other Tier II resources. While RES could be satisfied at a lower cost with RECs from other resources, the net-metering statute[96] requires that utilities purchase and retire the RECs for RES compliance. The costs associated with net-metering RECs are discussed in further detail in the net-metering report included as an appendix to the Annual Energy Report.

As outlined in Commission Rule 5.100, in 2017 net-metered customers received $60 per MWh ($0.06 per kWh) more for their generation when they transferred their RECs to the host utility, compared to if the customer elected to retain the RECs. In July 2018 the REC adjustor differential decreased to $50 per MWh, and in July 2019 it decreased another $10 per MWh to $40 per MWh, where it remains today. Given the current favorable customer economics of transferring RECs to utilities, the Department expects most future net-metering customers to transfer their RECs, which will then be used by host utilities toward Tier II obligations. The unpredictable pace of net-metering deployment has made it difficult for utilities to strategically procure other Tier II resources. The result is that some utilities, in preparation for RES, invested in Tier II-eligible projects or entered into long-term bundled contracts and now have over-procured Tier II resources in the short-term and must sell excess RECs out of state, often at a loss. Currently, regional premium REC markets are relatively balanced and trading around $40/REC, so while DUs are acquiring some net-metered RECs at $60/REC, they are selling equivalent RECs at a loss. In the scenarios analyzed by the Department for this report, RECs from net-metering generation are more expensive than RECs from all other Tier II resources.

[96] 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)

Effect of Tier III Electrification on Tier I and Tier II Obligations

Several eligible Tier III measures offer sources of new load for utilities.[97] The RES model allows the user to specify which Tier III measures will be used to meet obligations. [98] If utilities are assumed to incentivize Tier III measures that build electric load, their retail sales will be higher and thus Tier I and Tier II obligations will also be higher, but those costs will be offset by increased retail sales revenue. 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 III compliance, this would amount to over 104,000 new EVs on the road between 2020 and 2029, and a total of 288,000 MWh of new load by 2029 that is not in the baseline load forecast. Higher costs for utilities to serve the additional load would be offset by additional retail revenues from increased electric sales. In contrast, if utilities exclusively incentivized non-electric Tier III measures, like biofuel burning equipment or weatherization upgrades, there would be no additional load or costs, and the Tier III costs would not be offset by higher retail sales.

The Department has assumed the following constant allocation of technologies will be used to meet Tier III requirements in each year of the projection:

Tier III Technology Allocation	
Cold Climate Heat Pumps	40%
Electric Vehicles and Charging Stations	40%
Weatherization	5%
Custom	10%
Tier II RECs	5%

This allocation is intended to be a proxy for the state over 10 years and does not represent forecasted adoptions of each technology. Each utility will have a different allocation of measures based on its service territory and customers' needs that will change over time. For example, Burlington Electric Department customers are primarily natural gas customers as well and much less likely to adopt CCHPs than customers that primarily heat with oil, due to poor customer economics. This illustrative allocation was informed by utilities' Tier III plans, Efficiency Vermont's Demand Resource Plan, and conversations with the utilities. The allocation does not, however, consider any other state goals such as those for weatherization or electric vehicles. The Department does not expect this to be the actual allocation in each year but uses this illustrative allocation of measures in an effort to quantify the associated additional load and costs. In the first two years of compliance, more than 70% of obligations were met with custom measures, but by year 3, just 14% of compliance was met with custom projects. Custom projects will likely become increasingly difficult to identify going forward. The electrification of transportation, including commercial scale, is also expected to ramp up to help achieve requirements. With the current calculation method for Tier III credits where a heat rate is applied to fossil-fuel offset

[97] Tier III 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 Department is a member. Since the establishment of the RES in 2015, the TAG has been developing calculations that prescribe the amount a given Tier III measure will be credited toward a DU's Tier III obligation, informed by a variety of primary and secondary empirical and engineering studies.

[98] The current version of the RES model includes CCHPs, EVs, weatherization and custom projects as Tier III compliance measure options. For all projections, the technology allocation is kept constant over the 10-year projection.

measures, utilities have generally not focused on weatherization because the credits are discounted, and no additional load is gained.

Tier III Compliance Cost Components

Incentive Payments

Fossil-fuel price levels and project incentives influence customer adoption of Tier III measures. In general, consumers are assumed to act rationally, and the benefits of a Tier III 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 install, own and operate a substitute Tier III measure. Therefore, in a low fossil-fuel price environment, utilities may need to offer a greater financial incentive to encourage Tier III measures. Conversely, when fossil fuel prices are high, then the cost to operate traditional fossil fuel equipment relative to alternative Tier III measures is also high, and customers may not need as significant of a financial incentivize to invest in a Tier III measure.

The RES model allows for different assumptions about the future price of fossil fuels. In the scenarios analyzed by the Department 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 2029, 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%.

Retail rates are also affected by the fossil fuel scenario. For this analysis, retail rates are assumed to be tied to the market, inflation, and depreciation. The portion that is tied to the market is assumed to be 50% of rates, and includes costs associated with energy, capacity, and transmission.[99] Energy prices in New England tend to track closely with natural gas prices such that in the high fossil-fuel price scenario, wholesale electricity prices reflect higher natural gas prices which then flow through to higher retail electric rates. The opposite is true for the low fossil-fuel price scenario, which results in lower retail rates.

Program Administration Overhead

Utilities will incur costs to design, administer and document their Tier III programs. The scenarios the Department analyzed for this report assume these costs will total $800,000 in 2020, escalating by 3% thereafter.[100] 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.

Costs and Revenues of New Tier III Loads

If the Tier III measures incentivized by utilities create new electric load, then 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 costs included in this model do not include investments in transmission and distribution ("T&D") infrastructure that may be both significant and required to accommodate additional loads. The

[99] No T&D investments associated with upgrades to accommodate Tier III loads have been included in this analysis.
[100] Actual 2019 overhead costs were reported to be $758,195. See Case No. 20-0644 for 2019 RES compliance filings made by utilities.

incremental costs to provide capacity and transmission is determined by the operations of the Tier III equipment. If Tier III equipment increases peak loads, capacity and transmission costs will be incurred, increasing the cost to serve. Conversely, Tier III 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 III measures should be controllable and not increase peak loads so that they will help to offset other RES compliance costs. The contribution of new Tier III load to peak loads is a variable in the RES model and is used to test the financial implications of load management; the scenario resulting in the low incremental cost of RES assumed 10% of the new load is present at the time of the peak, and the high incremental cost scenario assumed 75% of new load would add to the peak.

Projected Program Impacts

In 2016, before the implementation of RES, Vermonters directly consumed around 103,000,000 mmBtu of fossil-fuel energy for heating buildings and transportation.[101] Additionally, Vermonters indirectly consumed around 22,000,000 mmBtu of fossil fuel through electric usage.[102] Meeting the RES Tier III obligations requires ongoing reductions in direct fossil fuel consumption (or end-use consumption) of several tens of thousands of mmBtu each year. At this trajectory, Department estimates that end-use consumption of fossil fuels will be about 3,200,000 mmBtu lower in 2029 as a direct result of Tier III, a reduction of 2.6% relative to 2016 levels. Meeting the Tier I and Tier II requirements implies ongoing reductions in utility procurement of non-renewable, translating to hundreds of thousands MMBtu per year. 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 almost 15,500,000 mmBtu in 2029, a reduction of 12% reduction from 2016 levels.[103] Additionally, Vermont's portion of electricity from nuclear has increased from 13% in 2016 to 28% in 2019; while that share could decrease with contract expirations, the Department has assumed that 28% will continue to come from nuclear or other non-fossil fuel sources for the entire projection period. Overall, across all energy using sectors, the Department estimates that by 2029 Vermont will consume around 15% less fossil-based energy than it does today as a direct result of RES, with an additional 5% reduction resulting from the increased share of nuclear. Similarly, CO_2 emissions could be reduced by 870,000 tons in 2029 as a direct result of RES, a reduction on the order of 11% relative to recent levels across all sectors (estimated to be around 10,000,000 tons[104]), with an additional 273,000 tons of carbon saving resulting from the assumed increased share of electricity from non-fossil generators.

Using the RES model, the Department finds there to be a wide range of credible outcomes of the total incremental cost of the RES requirements over the next ten years (2020-2029). Cumulative costs could be as low as $30 million in net present value ("NPV"), or as high as $156 million. The primary net cost drivers in the model are:

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

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

[103] Much of Tier I and Tier II savings are a result of purchasing RECs from existing resources, so while Vermont is reducing its fossil fuel consumption, the regional impact on incremental renewable energy is limited.

[104] Vermont Greenhouse Gas Emissions Inventory Update: Brief 1990-2015, published the Agency of Natural Resources.

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

The table below summarizes the assumptions used to develop this credible range of outcomes over the next 10 years.

	HIGH INCREMENTAL COST	LOW INCREMENTAL COST
REC Price Forecast	HIGH	LOW
NM Adoption 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	-$28,000,000	-$60,000,000
TOTAL Cost of RES	$171,000,000	$8,000,000
Rate Impact	5.02%	0.56%

The most significant difference between the upper and lower bounds in the table above is related to Tier I REC prices. The Department expects Tier I compliance costs to be around $32 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 II 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 III 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 meet Tier III 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 III 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.[105] Low electric rates are critical to successful electrification.

As an example, if utilities were to rely exclusively on heat pumps to meet Tier III obligations, by 2029 they would be selling an additional 340,000 MWh of electricity. This additional load represents almost 6% of current retail sales (about 5,400,000 MWh annually) and has a meaningful moderating effect on upward rate pressures if the new load does not contribute to peak loads. If electric prices are low relative to fossil fuel prices, there will be less need for incentives from utilities to encourage the

[105] This dynamic is clear under the low-cost scenario. While there is $26.4 million cost associated with RES over 10 years, the total retail sales will be higher as a result of RES, and therefore electric rates ($/kWh) will be lower.

adoption of heat pumps. Conversely, if electric prices rise and customer economics of installing a heat pump are marginal, then a greater incentive from utilities will be required to encourage the adoption of heat pumps. All but one scenario analyzed for this report resulted in upward rate pressure. In the scenarios the Department considers most likely, the rate impacts attributable to the RES ranged from a 1% to 3% percent higher than a baseline rate path on average over the next ten years. In the unlikely scenario where Tier III is met without load building measures (i.e., weatherization) the annual rate impact averaged 4.5%.

The higher compliance cost-scenarios analyzed by the Department for this report assume that 75% of all new electric load resulting from Tier III 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 net upward rate pressure over time.

Overall, the Department anticipates the RES will result in 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 III 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. This is significantly more than the current residential retail rate of roughly $164 per MWh (and would thus contribute to upward rate pressure). If those same technologies can avoid electric consumption at peak times though, it might only cost utilities $30 to $50 per MWh. This does not account for the fact that increases in peak could also result in increased distribution and subtransmission costs related to upgrades required to serve increased loads.

The Standard Offer Program

The Standard Offer program was established in 2009 to stimulate the development of small, in-state renewable resources. Under the program, a third-party entity, currently VEPP, Inc., contracts with developers and allocates the energy, capacity, and RECs to utilities, along with the corresponding costs, based on each utility's load ratio share. Vermont utilities are required to purchase the output of the projects at the contracted prices. Utilities demonstrating 100% renewability are exempt from the program.

At the end of 2020, the program had contracted for 113 MW of renewable resources, with 70 MW of those resources commissioned as of December 11, 2020. A summary of the Standard Offer projects that have been contracted, built, and that are in development is shown in Table 5, below.

STANDARD-OFFER PROJECT SUMMARY

Technology	Contracted Capacity (kW)	Contracted Number of Projects	Online Capacity (kW)	Online Number of Projects	In Development Capacity (kW)	In Development Number of Projects
Biomass	865	1	865	1	0	0
Farm Methane	5,249	15	5,205	14	44	1
Food Waste	3,388	5	0	0	3,388	5
Hydroelectric	4,939	6	4,939	6	0	0
Landfill Methane	0	0	0	0	0	0
Large Wind	0	0	0	0	0	0
Small Wind	886	15	0	0	886	15
Solar PV	97,647	57	58,797	39	38,850	18
TOTAL	**112,974**	**99**	**69,806**	**60**	**43,168**	**39**

Table 5: Standard-Offer Summary for projects on-line courtesy of VEPP, Inc.

In 2019, Standard Offer projects generated 109,516 MWh, which was purchased by Vermont utilities. In 2020 (through November), 112,185 MWh was generated. The total program cost in 2019 was approximately $22 million, with an average cost of $201/MWh. The total program cost in 2020 through November was $22.3 million, with an average cost of $199/MWh. It is important to note that Standard Offer contracts for all technologies, except farm methane, are for the entire plant output of a project, including energy, capacity, and RECs. Utilities can then use the RECs for RES Tier 2 compliance or sell the RECs out-of-state, which during robust REC markets can help to reduce the cost of the program. Actual generation, costs, average price per MWh, and average capacity factor for the past six years are shown in Table 6, below.

HISTORICAL STANDARD OFFER PERFORMANCE

Year	MWh Generation	Program Cost	Average Price per MWh	Avg. Capacity Factor
2015	90,126	$20,100,371	$223	20.1%
2016	101,377	$22,042,023	$217	19.8%
2017	103,519	$21,342,884	$206	18.8%
2018	103,658	$21,250,884	$205	18.1%
2019	109,516	$21,991,994	$201	17.9%
2020	112,185	$22,273,981	$199	20.0%

Table 6: Source: VEPP, Inc.

Figure 5, below, shows the actual installed capacity at the end of each year, the contracted capacity at the end of each year, and the targeted cumulative capacity for each year going forward.[106]

[106] The capacity shown in Figure 5 only includes projects that count towards the Program’s 127.5 MW capacity; farm methane projects are excluded from the totals above.

STANDARD-OFFER CAPACITY

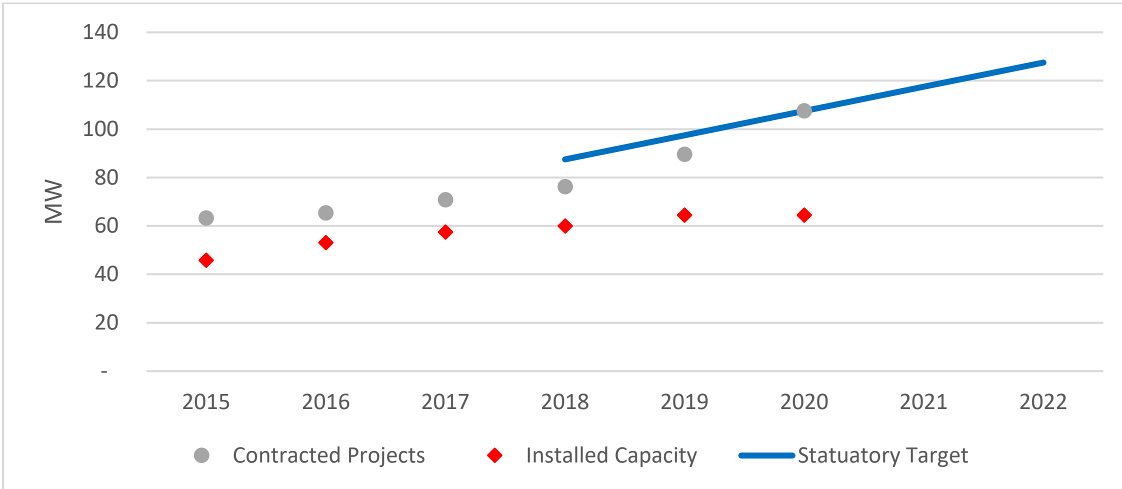

Figure 31: Actual historical installed capacity, contracted capacity, and cumulative contracted capacity targets through 2022.

Interest and participation in the Standard Offer program have been strong since the program's inception. Initially the program offered rates that were set based on administratively determined estimates of the cost to build a project of a specific technology type. However, it quickly became clear that lower prices could be achieved through a competitive market solicitation, resulting in Act 170 of 2012, which enabled the Commission to conduct an annual RFP to procure the desired capacity. The annual RFP, which awards contracts to the lowest-bidding resources, has resulted in lower contract prices, as evidenced by the decreasing average price per MWh shown above in Table 6. Below is a summary of the number of offers received in each RFP.

STANDARD-OFFER RFP PARTICIPATION

Year	Developer Offer	Utility Offer
2013	34	1
2014	18	1
2015	22	2
2016	25	0
2017	30	2
2018	13	1
2019	36	2
2020	25	2

Table 7: Source: VEPP, Inc.

The RFP bid process has resulted in significantly lower prices for newer projects. Solar projects that were awarded a contract in the early years of the program received a rate of $0.30/kWh compared to newer projects that are online with prices as low as $0.095/kWh. Projects have been awarded contracts at prices as low as $0.08/kWh, although these project have not yet been built. This declining price trend is a result of both declining solar costs as well as allowing a competitive market solicitation process.

The statute provides a clear directive to encourage the development of different technologies through technology allocations. However, it has been difficult for technologies other than solar to be awarded a contract, reach all the milestones, and achieve commissioning. Almost all the projects built in recent years have been solar, as shown in Figure 6. The second largest category of Standard Offer resources are farm methane projects, which were financed by market-based contracts before the implementation of the Standard Offer program and transferred to the Standard Offer program when market prices began to decline. The Commission has attempted to address this lack of technology diversity by instituting technology allocations (set-asides for technologies other than solar), yet the Standard Offer portfolio of new acquisitions remains heavily reliant on solar.

TOTAL INSTALLED CAPACITY OF STANDARD OFFER PROJECTS BY FUEL TYPE

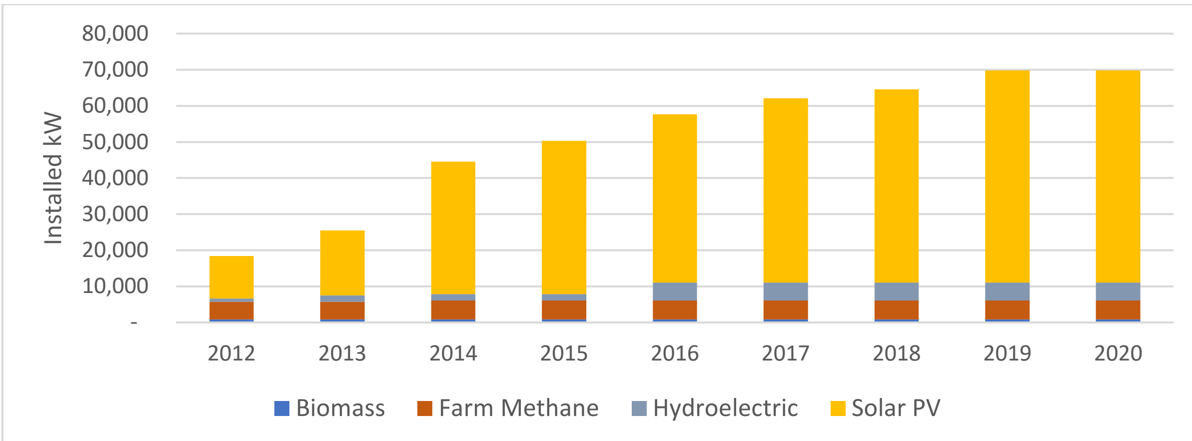

Figure 32: Installed capacity of Standard Offer projects by fuel type

On several occasions over the past two years, the Department has recommended that the program not be extended, in either length or capacity, and end as scheduled in 2022, for several reasons. The enactment of the Standard Offer program in 2009 came at a time when the development of renewable resources within the state was moving relatively slowly, and before the enactment of the RES in 2015. Since that time, the development of distributed renewable generation has matured and an administratively burdensome program like Standard Offer is no longer necessary to facilitate the deployment of new renewable resources. Additionally, some of the grid benefits of distributed generation – solar in particular – have declined considerably as constraints are now more likely to result from excess generation rather than load.

RES is the overarching state-level electric renewable policy, with the Standard Offer program contributing to the achievement of Tier II requirements. However, with the evolving renewable landscape, the Department does not believe the continuation of the program is in the best interests of Vermont ratepayers and instead inhibits progress toward the goals of the Comprehensive Energy Plan. Utilities cannot control the pacing of Standard Offer projects, which makes planning for RES obligations highly uncertain and can result in higher costs. In addition to the unpredictability of Standard Offer projects, the value that the projects provide has eroded as a result of the state's declining and flatter loads and increased distributed generation, such that in some cases, these projects impose distribution costs rather than obviating the need for system upgrades, as originally intended. Another area with negative consequences is the imposition of unnecessary costs of wheeling power from the service territories of utilities that are hosting a disproportionate share of generation. Furthermore, in recent years, significant time and money has been spent litigating the legality of the Standard Offer program.[107] For these reasons, the Department recommends that the Offer program be allowed to end in 2022.

Market Assessment

30 V.S.A. § 8005b(c)(5)

Renewable Energy Markets

Renewable energy markets in New England are driven by state RPS. Throughout New England, compliance with RPS requirements is demonstrated with the retirement of RECs in NEPOOL GIS. With each MWh of electric generation from a qualified renewable resource, a renewable attribute – a REC – as well as an environmental attribute is created. An eligible renewable resource can qualify its generation in different states and attributes associated with that resource receive a "REC" designation for each state (e.g., an attribute can be qualified for VT Tier II, MA Class I, and CT Class I). 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 compliance, and 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.

With the implementation of Vermont's RES in 2017, all six New England states now have active RPS or RES policies. Each RPS program has multiple classes – referred to in Vermont as tiers – which are used to differentiate incentives by energy technology, vintage, emissions, and other criteria, based on state-specific policy objectives. Regional premium REC requirements are intended to create demand for new renewable energy and stimulate development. [108] In order to achieve continued growth of renewable energy, the RPS targets for these classes increase annually. Existing REC classes focus on resources that were in service prior to the implementation of the RPS and are generally described as "maintenance tiers."[109] They are designed to provide sufficient financial incentive to keep the existing fleet of renewable resources in reliable operation. Generally, RPS requirements for the existing tiers remain flat, except for Vermont's Tier I requirement, which increases every third year.

REC markets provide utilities an opportunity to obtain RECs and comply with renewable requirements without having to make a long-term commitment of purchasing or generating physical power. However, REC markets can be volatile, illiquid, and lack transparency. Adding to the complexity of the markets, RPS eligibility by state and class varies, which can result in convergence (e.g., when eligibility is similar in multiple states) or divergence (e.g., when eligibility is unique to a state) of REC prices by state. For example, Vermont Tier II eligibility requires the generator to be less than 5 MW and interconnected to a Vermont DU, whereas MA Class I has broader eligibility requirements, thus greater supply, which may result in Vermont Tier II RECs trading at a premium to MA Class I if there is a tight supply of Tier II RECs in Vermont.

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[107] These include multiple appeals of PUC orders filed at the Vermont Supreme Court, as well as cases challenging the consistency of the program with federal law, which have been filed at the Federal Energy Regulatory Commission and in Vermont Federal District Court.

[108] Premium RECs include VT Tier II, CT Class I, MA Class I, ME Class I, NH Class II, and RI New.

[109] Existing RECs include VT Tier I, CT, MA & ME Class II, III & IV, and RI Existing.

Theoretically, REC prices should be the revenue, in addition to energy and capacity, required by renewable resources to make a project economically viable. When energy and capacity revenues are high, then REC prices should be low; when energy and capacity revenues are low, then REC prices should be high. However, in reality, prices are a function of supply and demand. Supply is the qualified renewable generation in the region, which increases with additional new renewable resources, but can also change with a change in eligibility criteria (e.g., the disallowance of biomass). Demand is a function of load and renewable requirements, which can change significantly with a change in legislation. Early renewable markets experienced a shortage of supply as RPS requirements increased faster than resources could come online, resulting in prices near the ACP. Then, renewable development outpaced demand, resulting in very low REC prices. Now, after several large-scale projects were delayed, the regional supply and demand has become more balanced with prices for 2020, 2021, and 2022 trading around $40/REC. Prices in the longer term, for 2023 and 2024 RECs, are in the low- to mid-$30s.[110] The lower prices are a result of more projects expected to be online, as well as proposal to lower the Massachusetts ACP.[111]

All RPS programs in New England have an ACP, which is the price paid when insufficient RECs are retired. The ACP acts as a ceiling for trading prices. The current proposal in Massachusetts to lower the ACP would effectively lower the price ceiling on the regional markets going forward. Historically, RECs have traded at a wide range of prices, with Class I RECs trading as high as $64/REC in 2014 and as low as $2/REC in 2017. In 2019, the Tier I ACP was $10.40/REC and Tiers II and III were $62.42/REC; each will escalate annually with the consumer price index (CPI). Historical MA Class I REC prices are shown in Figure 7.

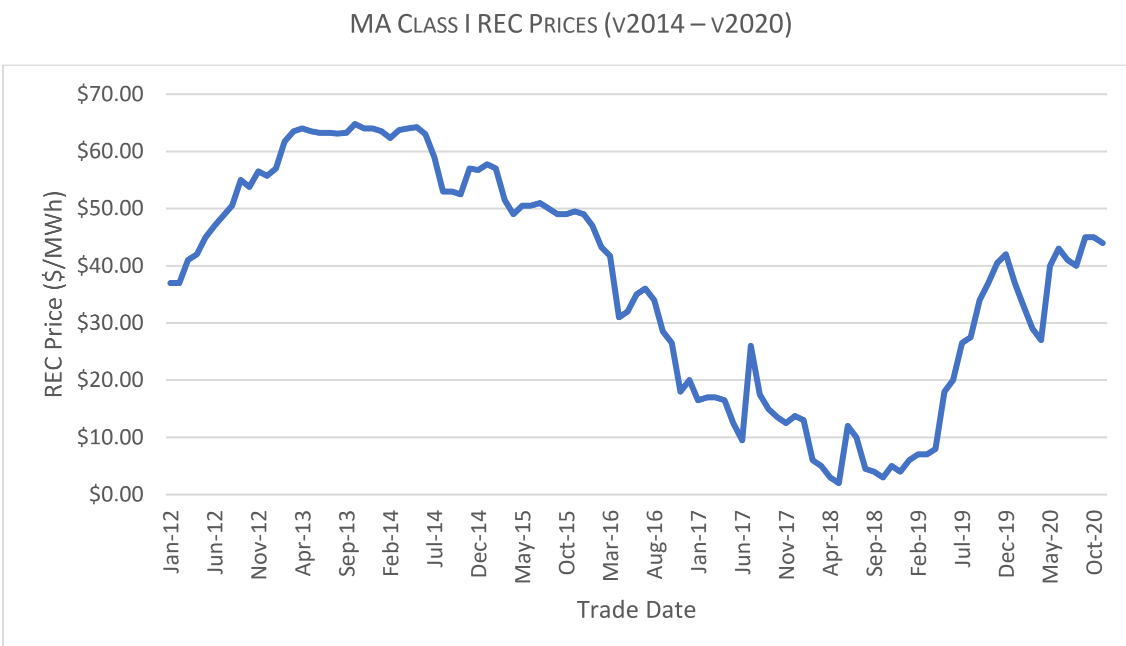

Figure 33: MA Class I REC Prices in New England (vintages 2014-2020), courtesy of GT Environmental REC Brokers

[110] REC pricing reflects data through November 2020.

[111] The 2020 MA ACP was $71.57/ MWh escalating annually at CPI. The proposal would drop the ACP down to $60 in 2021, $50 in 2022 and $40 in 2023 and thereafter.

In Vermont, Tier I resources include any renewable generator in ISO-NE and renewable imports from Quebec and New York. This category of "existing" RECs has consistently been in excess supply since the inception of renewable standards in the region, as there generally is no requirement that the eligible resources be new or limited to a certain size. Tier I RECs have historically traded around $1/MWh.[112] The emergence of the Vermont Tier I market has increased regional demand slightly and caused modest price increases in the existing market. As Tier I requirements continue to increase, additional substantive increases to the price are not expected because Vermont allows for the use of HQ and NYPA attributes for compliance, which are not currently eligible in other states.[113] However, as other states put more emphasis on emissions reductions and move towards clean energy standards, it is conceivable that the demand for these HQ and NYPA attributes will increase, which would result in higher Tier I prices. 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.

Tier II 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 are a limiting factor on the tradable Tier II REC supply going forward and may result in Vermont Tier II 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 II RECs in the long-term. Instead, most Tier II RECs will come from net-metering, Standard Offer, utility-owned resources, and long-term bundled purchases. Given the recent pace of net-metering adoption, many utilities expect to meet most, or all, Tier II compliance needs for the next five years with RECs from net-metering projects. [114] Standard Offer projects, from which utilities are required to purchase their pro-rata load share (except DUs that are exempt) also include Tier I and/or Tier II RECs. [115] However, even though Standard Offer projects commissioned prior to July 1, 2015 are eligible for Tier I compliance, as previously described, the Department expects utilities to sell these higher value RECs out of state as Class I resources. Additionally, several utilities own or have existing contracts to purchase the output from Tier I and/ or Tier II qualified generators. If a utility does not have sufficient RECs to cover its obligation, in the near-term, the Department expects sufficient excess RECs will be available for purchase at prices lower than the ACP and 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 Tier II 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 II.

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[112] 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.

[113] Currently unbundled attributes from a neighboring control area may be used for compliance if the utility can demonstrate ownership, eligibility and that attributes have not been claimed in any other jurisdiction.

[114] 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)

[115] 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."

Energy Efficiency Markets

Robust energy efficiency efforts in Vermont will drive down the cost of compliance with the RES. Efficiency measures not only reduce the energy that utilities must purchase but also reduce the RES obligation of the utility. A more detailed discussion of energy efficiency markets is included in the main body of this Annual Energy Report.

Every three years, as part of the Public Utility Commission Demand Resource Plan (DRP) proceeding, the Department commissions an evaluation of the remaining electric efficiency potential in the state, to help inform the setting of appropriate budgets. This study was last updated in 2019.[116] Four types of potential were assessed, including technical potential, economic potential, and achievable potential (achievable potential includes two types of potential, maximum achievable and program achievable potential). The realistic achievable potential, based on historical incentive levels and corresponding program adoption rates, is approximately 14.4% of the forecast kWh sales in 2037. The potential for efficiency improvements remains high in the state.

Efficiency programs in Vermont and other larger states have helped move the market more generally, helping lower costs of efficient appliances and lighting faster than would have otherwise occurred. Federal appliance and lighting standards reflect this movement toward affordability when they require efficient appliances and lighting.

Renewable Energy Programs Impact on Rates

Over the past five years, Vermont rates have remained relatively stable. As shown in Table 8, while inflation averaged 1.8% between 2015 and 2019, the Vermont blended statewide rate[117] experienced an average annual increase of 0.7% over the same timeframe. Although growth in rates has remained lower than inflation in recent years, costs such as those related to net metering and transmission will likely spur increased upward rate pressure in the future. In the 2020 net-metering Biennial Review,[118] the Commission recently approved a 6.5% increase in the statewide blended rate to 16.41 cents/kWh, based on 2018 kWh sales and 2019 rates. This will go into effect February 2, 2021.

While utility fixed costs remain relatively consistent, the net-metering program has driven reduced retail sales while requiring utilities to procure net-metering resources that are above market cost, shifting costs to non-participating customers through increased rates. Further, while Vermont's early adoption of distributed renewables (particularly solar) helped lower the state's peak load and therefore the related share of regional transmission costs, these early gains have receded as other Vermont peaks occur after dark throughout the year, and New England states have caught up in the deployment of renewables. Transmission costs must still be recovered and as the peak demand decreases, the rate increases.

[116] The full study can be found at https://publicservice.vermont.gov/content/vt-energy-efficiency-potential-study-2019. The Department's most recent 2019 Energy Efficiency Market Potential Study (2019 MPS) was conducted by GDS Associates

[117] As defined in Rule 5.100, the statewide blended rate is the weighted average of all electric company blended residential retail rates, weighted based on a company's kWh sales.

[118] Case No. 20-0097-INV.

BLENDED STATEWIDE RETAIL ELECTRIC RATES IN VERMONT OVER TIME COMPARED TO INFLATION

	2015	2016	2017	2018*	2019	**5-Year Avg**
Vermont Blended Residential Rate(cents/kWh)	14.90	14.90	14.90	15.15	15.40	15.03
Change in Electric Rates	0.00%	0.00%	0.00%	1.68%	1.65%	0.7%
Inflation Rate	0.7%	2.1%	2.1%	1.9%	2.3%	1.8%

Table 8: Blended statewide retail electric rates in Vermont compared to inflation

*Since the rate changed halfway through 2018, this is an average of the two rates (14.9 and 15.4 cents/kWh).

Figure 8 compares the average retail price of electricity[119] in Vermont to those in other New England states and New York. Over the past several years, the average retail price of electricity in Vermont has remained roughly 2-3 cents/kWh below most other New England states. In 2019, Vermont had the second-lowest average price in New England (second only to Maine). When also considering New York, Vermont has the third lowest in the region.

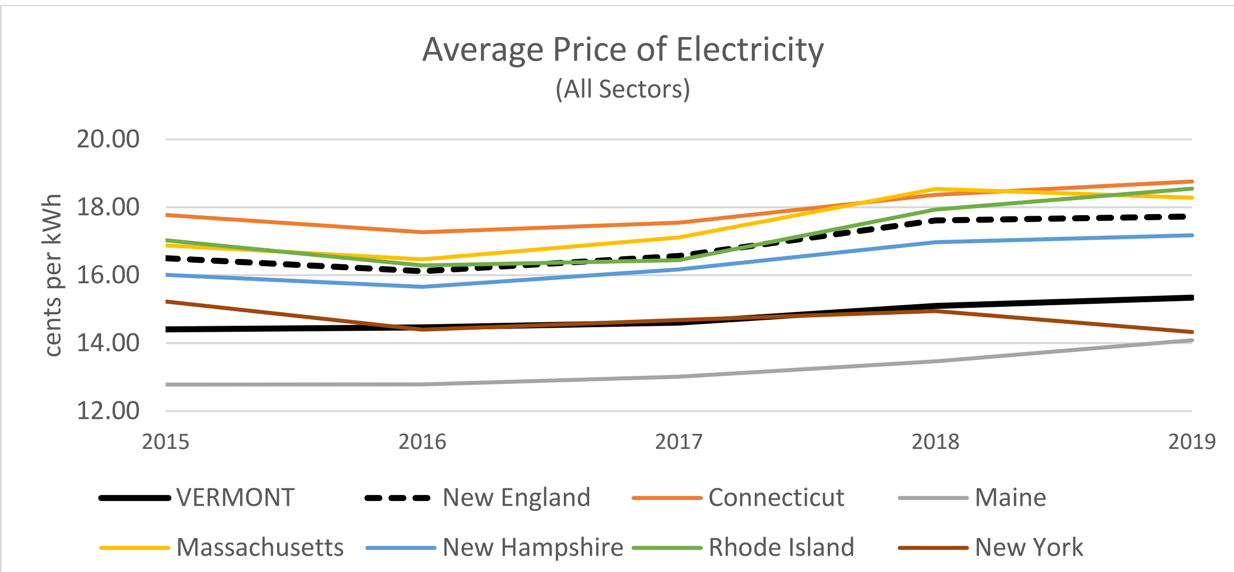

Figure 34: Comparison of average retail price of electricity in New England and New York[120]

[119]U.S Energy Information Administration (EIA). *Electricity Data Browser: Average retail price of electricity*, Retrieved from https://www.eia.gov/electricity/data/browser. Note, to compare Vermont electric rates with the New England states and New York, we use EIA data on average retail price of electricity as a proxy. EIA calculates the average price of electricity to customers by taking the ratio of electric revenue divided by sales, so provide an estimate for "cost per unit of electricity sold". EIA uses information on the weighted average of consumer revenue and sales within and across sectors. While this data does not represent actual rates, it provides the best way to compare costs across states.

[120] U.S Energy Information Administration. *Electricity Data Browser: Average retail price of electricity*, Retrieved from https://www.eia.gov/electricity/data/browser.

Since Vermont electric utilities are vertically integrated, and therefore own generation, transmission, and distribution systems used to serve retail customers, they have greater certainty over the long-term load they will serve than other New England utilities. As a result, they can enter long-term power procurements, and while these long-term procurements prevent Vermont utilities from accessing full benefits of low market prices, they tend to lead to less volatile rates over time. Conversely, most other New England states deregulated in the late 1990s toward a paradigm of retail choice. In these states, utilities generally own and operate the distribution grid, while third-party providers acquire and sell electricity. Unlike Vermont, retail providers in deregulated states do not have as much long-term certainty in the amount of load they will serve and have therefore been limited to short-term procurements[121], which can lead to more volatile rates.

Since January 2019, five Vermont utilities have submitted six tariff filings, requesting five rate increases.[122] None of these increases have been directly caused by compliance with RES or the Standard Offer program, although a handful of tariff filings for rate increases did reference a need to increase rates due to depressed REC markets, lost revenues due to an increase in net-metering, or the need to procure above-market-price solar resources to avoid the development of even costlier net-metering projects.

While RES is the overarching framework in Vermont, both the Standard Offer program and net-metering programs complement those goals. Net-metering in particular is making a significant contribution toward meeting RES requirements. The current net-metering program requires that Vermont DUs purchase net-metering RECs and in 2019, RECs from net-metering systems constituted over half (53%) of Tier II REC requirements. In the current low-priced REC environment, this leads to paying an excess price premium for RECs, and in certain instances can lead to purchases in excess of both quantity and price of their RES requirements. Therefore, the Department believes the program is out of alignment with RES and should be reconfigured to reduce the burden on ratepayers, while still advancing our renewable goals pursuant to the RES.

Recommended Statutory Changes

The Department is not recommending specific statutory changes related to RES or the Standard Offer program. The RES continues to be an effective mechanism for addressing climate emissions from the electric sector. The Standard Offer program is scheduled to end in 2022, after which time, Vermont's electric utilities will continue to meet the Tier II requirements through their own procurement process.

[121] This dynamic is beginning to shift with the implementation of long-term statewide renewable procurements in Massachusetts and Connecticut.

[122] Information on these rate cases can be found in case numbers 19-1932-TF and 20-1407-TF (Green Mountain Power; GMP), 19-3020-TF (Hyde Park), 19-4585-TF (Vermont Electric Cooperative), 19-4576-TF (Washington Electric Cooperative), and 20-1234-TF (Enosburg Falls). GMP rates are regulated under a multi-year regulation plan pursuant to 30 V.S.A § 209, 218, and 218d (see case no. 18-1633-PET), which sets much of the costs that go into rates for a three-year period. Under this plan, base rates are updated annually with quarterly adjustments as needed. The current plan covers FY2020-22, and the cases referenced here represent the first two base rate filings, which included one base rate increase.

Appendix E – Net Metering Report

Report on Vermont Net Metering Program

A Report to the Public Utility Commission and the Vermont General Assembly Pursuant to 30 V.S.A. § 8010.

Prepared by the Department of Public Service

January 15, 2021

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Overview

Vermont's net metering program has changed considerably since it was first authorized in 1998. Early iterations of the program were designed to incentivize small-scale (15 kW) projects that were used to offset the onsite electric consumption of the net metering customer. Under the current program, projects can be up to 500 kW and there is no requirement that a net metered project actually offset a customer's load, although projects directly tied to a customer's usage receive higher compensation. In 2019, approximately 75% of the generation produced by net metered resources was exported directly to the grid and not used onsite, with participating customers receive bill credits for that exported generation. In effect, net metering has become a financial construct that allows customers to offset their electric bills by supporting the development of a net metered system.

This model has resulted in a significant expansion of the amount of distributed renewable generation in Vermont and also increased the number of clear energy jobs in the state. However, as with any state-mandated program, there should be periodic evaluations of whether the benefits associated with the program are outweighed by the costs. As the amount of net metering has grown to almost 30% of Vermont's peak load (a significantly higher percent than any other state), it has become clear that the current structure of net metering will need to be modified to reduce the financial impacts on non-net-metered customers and to help advance Vermont's transition to a low-carbon economy.

Under the current net metering structure, new participating customers are compensated at $0.17/kWh (prior net metered customers generally receive higher compensation). Outside of the net metering program, new solar resources are being built for a cost of less than $0.10/kWh. All electric customers are paying this differential, and since net metering customers have reduced their electric bills, the customers causing this cost shift do not equally share the burden of these additional costs. Customers have the right to manage their electric usage, including through on-site generation to reduce purchases from their electric utility. However, there is no corresponding right to have other electric customers subsidize this practice; and with increasing adoption of heat pumps and electric vehicles, net metering is starting to result in Vermonters paying for the heating and transportation costs of net metered customers in addition to the electric costs.

New renewable generation can be procured in multiple ways, and almost all other options come at significantly lower cost than the current net metering program. A net metering program that would promote Vermont's clean energy goals in an equitable manner would be structured to allow participating customers to offset on-site consumption in real time and receive compensation for the generation exported to the grid at the value of that generation to other electric customers. This structure would return the net metering program to its roots of incentivizing customers to offset their onsite energy usage and would better align the net metering program with promotion of distributed, flexible loads.

History of Net-Metering in Vermont

In 1998, Vermont enacted net-metering, requiring electric utilities to permit customers to generate their own power from small-scale renewable energy systems of 15 kW or less. Farms could have larger, anaerobic digesters systems up to 100 kW. The utilities were required to allow net-metering up to 1% of their 1996 peak demand, and any excess power (not consumed on site) generated by these systems could be fed back to the grid, running the electric meter backwards. Excess generation rolled over month to month as kWh but was zeroed-out on December 31st.

The net-metering statute was changed in 1999 and almost annually after that, with major modifications in 2001, 2007, 2012, and 2014. These changes included:

- Raising the percent cap of net-metering to 2%, then 4%, then to 15% in 2014.
- Increasing the allowed net-metering system capacity to 150 kW, then 250 kW, then 500 kW in 2011.
- Allowing for credits to roll forward on a 12-month basis. In 2012, the kWh credits were changed to monetary credits and applied to non-energy charges on the electric bills, including monthly service charges, reducing some customers' bills to $0.
- Group net-metering was initially restricted to farmers and their meters. In 2007, group net metering was expanded to all customers as long as the group members were contiguous. Group net-metering was eventually made available to all customers within a service territory.
- Established a simplified registration and permitting process for systems under 5 kW. This was expanded to 10 kW, then 15 kW, and in 2017 to 150 kW for roof-mounted systems.
- Created a solar adder of up to $0.06/kWh for all solar net-metered systems (based on the solar adder GMP had been paying to solar net-metered systems in its territory). The legislation required the solar adder be paid for ten years from the commissioning of the system and initiated a Commission process to determine the compensation framework for net-metering going forward.

Act 99 of 2014 moved net-metering out of the statutes and created a regulated net-metering program administered by the Commission. The Commission was charged with putting a new "Net-Metering 2.0" program in place in 2017.

In 2017, the Commission established new rules for net-metering as required by Act 99. Notably the new net-metering program eliminated the cap of net-metering and the solar adder and created siting adjustors for projects on so-called preferred sites and REC adjustors for projects that transfer the RECs to the utility (before 2017, RECs were owned by the customer by default).

Rates, Deployment, and Technology Types

Rates

Since Net-Metering 2.0 was first implemented in 2017, the compensation rates have been periodically evaluated and adjusted to ensure that the requirements set forth in the statute are met. Specifically, the net-metering statute, under 30 V.S.A § 8010(c)(1), requires the Commission to promulgate rules that establish and maintain a net-metering program that:

> (A) advances the goals and total renewables targets of [30 V.S.A. Chapter 89] and the goals of 10 V.S.A. § 578 (greenhouse gas reduction) and is consistent with the criteria of subsection 248(b) of [Title 30];
>
> (B) achieves a level of deployment that is consistent with the recommendations of the Electrical Energy and Comprehensive Energy Plans under sections 202 and 202b of [Title 30] . . . ;

(C) to the extent feasible, ensures that net-metering does not shift costs included in each retail electricity provider's revenue requirement between net-metering customers and other customers;

(D) accounts for all costs and benefits of net-metering, including the potential for net-metering to contribute toward relieving supply constraints in the transmission and distribution systems and to reduce consumption of fossil fuels for heating and transportation;

(E) ensures that all customers who want to participate in net-metering have the opportunity to do so;

(F) balances, over time, the pace of deployment and cost of the program with the program's impact on rates; and

(G) accounts for changes over time in the cost of technology; and

(H) allows a customer to retain ownership of the environmental attributes of energy generated by the customer's net metering system and of any associated tradeable renewable energy credits or to transfer those attributes and credits to the interconnecting retail provider, and:

(i) if the customer retains the attributes, reduces the value of the credit provided under this section for electricity generated by the customer's net metering system by an appropriate amount; and

(ii) if the customer transfers the attributes to the interconnecting provider, requires the provider to retain them for application toward compliance with sections 8004 and 8005 of this title.

Table 1 below summarizes net-metering compensation rates over time.

			RECs		CATEGORY				
Program	CPG Application Date	Statewide Blended Rate	Transfer to Utility	Retain Ownership	I	II	III	IV	Hydro
NM 1.0[123]	before 1/1/2017	$0.149	n/a		n/a				
NM 2.0	1/1/2017 - 6/30/2018	$0.149	$0.03	-$0.03	$0.01	$0.01	-$0.01	-$0.03	$0.00
NM 2.1	7/1/2018 - 6/30/2019	$0.154	$0.02	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.2	7/1/2019 – 2/1/2021	$0.154	$0.01	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.3	2/2/2021 – 8/30/2021	$0.164	$0.00	-$0.04	$0.00	$0.00	-$0.03	-$0.04	$0.00
NM 2.4	9/1/2021 –	$0.164	$0.00	-$0.04	-$0.01	-$0.01	-$0.04	-$0.05	$0.00

Table 9: Net-metering programs and rates

The net-metering rates – historical, current, and future – aim to strike a balance among the goals of the program. As conditions related to renewable technology, costs, the economy, and environmental goals

[123] After 2011, and before NM 2.0 (beginning January 1, 2017), systems received overall compensation of $0.19/kWh - $0.20/kWh and retained the RECs. Additionally, other up-front capacity-based incentives were also available.

shift, it is appropriate to reevaluate net-metering rates and make appropriate adjustments to achieve these goals at the lowest feasible cost, consistent with Vermont's least-cost planning framework.

Net-Metering Installed Capacity

While the net-metering program is open to a variety of technologies and fuel sources, as illustrated in the chart below, actual installations have been dominated by solar. Of the 264 MW of currently installed net-metering, almost 25 MW, or 97%, is solar, 2% is hydro (primarily pre-existing resources), and the remaining 1% is split between wind and biomass.

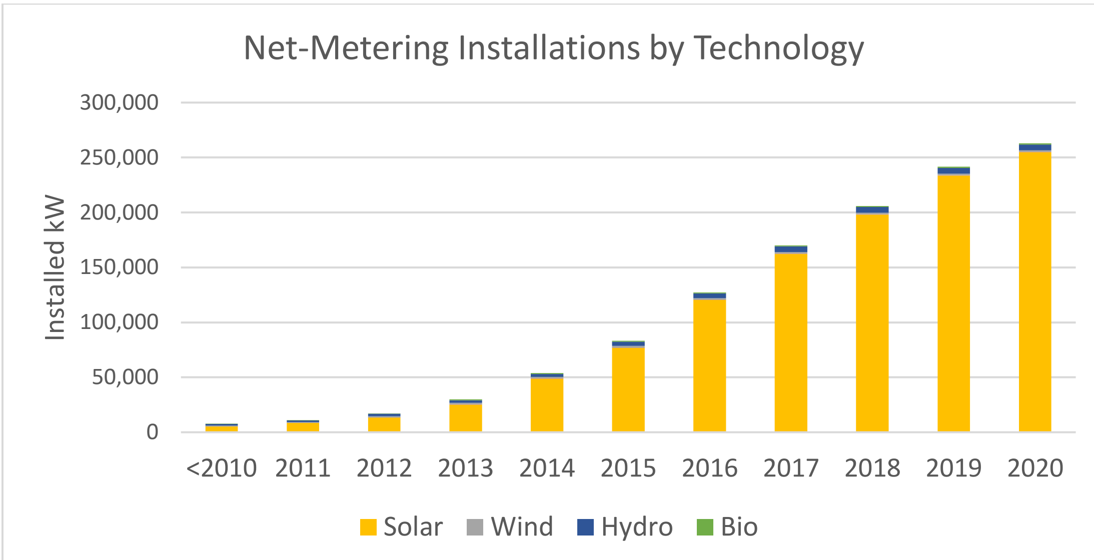


Figure 35: Cumulative net-metering installations by year

All Vermont utilities host net-metering projects. Green Mountain Power has the greatest share of projects, with more than 84% of Vermont's total capacity, exceeding its 74% share of the state's load. Burlington Electric Department, Vermont's mostly densely populated service territory, hosts just 1.8% of the state's net-metering capacity while serving 6% of the load. Table 2 below shows the distribution of net-metering installations among utilities.

Utility	Total Installed NM (kW)	2019 Non-Coincident Peak	NM as % of Peak Load	Percent of NM Capacity	Percent of Retail Sales
Green Mountain **Power**	221,266	684,450	32%	84.2%	76.4%
Vermont Electric **Cooperative**	20,720	80,082	26%	7.7%	8.4%
Vermont Public **Power Supply Authority**	10,251	71,019	14%	4.0%	6.4%
Burlington Electric **Department**	4,718	63,076	7%	1.8%	6.0%
Washington Electric **Cooperative**	3,722	16,067	23%	1.4%	1.3%
Stowe Electric Department	1,645	17,655	9%	0.6%	1.4%
Hyde Park **Electric**	528	3,370	16%	0.2%	0.2%
TOTAL	262,850	909,433	29%	100%	100%

Table 10: Net-metering deployment by utility

Net-Metering RECs

The current net-metering compensation structure provides an effective incentive for customers to transfer the RECs to the utilities. Net-Metering 1.0 did not differentiate compensation based on REC disposition. As a result, more than 98% of Net-Metering 1.0 projects retained the ownership of RECs and those projects cannot be claimed as renewable by Vermont utilities to be used for RES compliance. Compensation rates for Net-Metering 2.0 and beyond have had up to a $0.06/kWh differential between a system owner retaining (and potentially selling RECs in the regional REC market) versus transferring them to the utility. The current differential is $0.04/kWh, which still appears to decisively encourage REC transfers with more than 99% of RECs being transferred to utilities. In the 2020 Biennial Review, the Commission maintained the $0.04/kWh differential.

In 2018, net-metering RECs accounted for about 17% of utility Tier II compliance.[124] By 2019, with more systems online, net-metering RECs accounted for 53% of Tier II compliance.[125] As additional projects are built and transfer RECs to the utility, RECs from net-metering projects will continue make up a large share of Tier II compliance.

The Department expects about 25-27 MW of distributed generation will be needed annually to meet increasing Tier II RES requirements, assuming that the majority of Tier II compliance continues to be met by solar resources. That will include a variety of project types, from net-metering to Standard Offer to utility-owned and -contracted projects, in order to meet the RES requirements in the most cost-effective manner. Consistent with 30 V.S.A. §§ 202(b), 218c, 8001, 8010(c)(1)(F) and Vermont's least cost planning rubric, the highest priority should be ensuring that the state's renewable energy policies continue to deliver renewable energy at least cost. Currently, net-metering is the most expensive means for utilities to meet the Tier II requirements, and the current structure is a barrier to realizing greenhouse gas reductions, and to achieve the goals of the Vermont Electrical Energy and Comprehensive Energy Plans.

The Department notes that installation costs continue to decrease, though at more modest rates than previously experienced. From 2009-2014, installed prices saw significant annual declines, but these have since tapered off. The decreasing REC and siting adjustor compensation rates have thus been partially offset by the decreasing installation costs and higher retail rates, making net-metering profitable for both participating customers and developers over the years. Looking forward, solar installation costs are expected to continue to see declines like those experienced in recent years.

Other Net-Metering Technologies

Net-metering is available to renewable facilities in Vermont that have a capacity of 500 kW or less. The current net-metering rule allows for existing resources that meet net-metering eligibility requirements to convert that system into a net-metering system. This applies to existing facilities that do not need the additional compensation that net-metering provides and do not provide Tier II RECs for RES compliance. For example, several hydroelectric projects that had contracts under Rule 4.100 that have expired are

[124] In 2018 13,765 net-metering RECs were retired for compliance and an additional 5,629 RECs were banked and used for 2019 compliance. If all 2018 generated RECs were used for 2018 compliance, net-metering would have accounted for 24% of Tier II compliance.

[125] In 2019, the 5,629 vintage 2018 RECs were used for 2019 compliance along with 52,395 vintage 2019 RECs. In addition, 3,437 vintage 2019 RECs were banked for used in future years.

eligible for net-metering, although they are not providing new renewable power and the long-term contracts previously received should have paid most or all the initial capital costs of the project.

Economic Impacts of Net-Metering

Cost of Net-Metering

The net-metering compensation rates over time are summarized above in Table 1: Net-metering programs and rates. Each biennial review by the Commission has resulted in gradual decreases to the compensation rate, but net-metering remains one of the highest-cost renewable resources. Based on data collected from each utility, the cost of net-metering in 2019 was more than $40 million higher than the market value of the products provided, resulting in an inequitable cost-shift from participating net-metering customers to non-participating customers.[126] As previously noted, the large majority of net-metered projects are solar, so the Department's analysis of the costs and benefits of net-metering focus on that technology. Below, Table 3 shows the total net-metered generation and above-market costs in 2019 as reported by each utility.

Utility	Reduced Retail Sales (kWh)	Excess Generation (kWh)	Gross Generation (kWh)	Net Metering Above Market Cost
Barton	140,202	81,191	221,393	$25,441
BED	1,183,645	2,389,135	3,572,780	$401,020
Enosburg	261,024	902,107	1,163,131	$157,815
GMP	44,162,155	192,402,097	236,564,252	$34,963,804
Hardwick	622,278	757,625	1,379,903	$146,894
Hyde Park	152,384	337,384	489,768	$54,910
Jacksonville	52,447	155,291	207,738	$23,078
Johnson	38,630	716,399	755,029	$96,364
Ludlow	34,126	277,846	311,972	$42,087
Lyndonville	577,112	1,815,734	2,392,846	$298,601
Morrisville	246,076	851,856	1,097,932	$124,893
Northfield	118,398	606,821	725,219	$91,737
Orleans	27,817	7,068	34,885	$3,626
Stowe	1,071,634	416,324	1,487,958	$268,919
Swanton	109,653	1,737,318	1,846,971	$238,558
VEC	9,827,998	11,948,418	21,776,416	$2,653,006
WEC	3,455,322	604,509	4,059,830	$630,107
TOTAL	**62,080,901**	**216,007,123**	**278,088,023**	**$40,220,861**

Table 11: 2019 net-metering generation and above market costs

As shown in the table above, utilities must absorb a significant amount of "excess generation" from net-metered projects. When the profile of the generation does not match a customer's load shape, the customer must rely on the grid to balance their energy needs. At times when the generation is insufficient to meet demand, electricity is delivered from the grid. At times when generation is greater

[126] This figure represents the costs and values of solar projects in 2019, treating all net-metering projects equally. In recent years, the high adoption of solar in Vermont, and throughout New England, have effectively flattened loads and shifted peak hours. Therefore, projects that came online 10 years ago provided a greater value than projects that came online one year ago. This analysis does not assign a greater value to first-generation projects.

than on-site demand, the excess is pushed onto the grid – this is called excess generation.[127] Due to the predominance of solar as a net-metering resource and its seasonal nature, some of the highest generation occurs at times with the least demand. For example, in May, when days are long, and temperatures are moderate, solar is producing the most and demand for electricity is already very low. Additionally, group net-metering allows several customers to share the output of a single larger project, for which all the energy is exported to the grid. The result is significant amounts of excess generation. Customer generation that serves on-site load reduces the utility's need to purchase energy as well as reducing the burden on the distribution system. Excess generation, on the other hand, is essentially an power supply resource that utilities must purchase, but it does not provide the same distribution benefits as generation that is consumed onsite – unless it happens to be located very close to load centers.

In 2019, more than 77% of total net-metered generation was excess and exported to the grid. Credits for excess generation totaled more than $46 million in 2019 with the generation valued at less than $13 million. If net-metering systems are appropriately sized such that most of the generation is consumed onsite, or if excess generation were compensated based on the value provided as proposed by the Department in Docket 19-0855-RULE, then the cost-shift caused by net-metering would be greatly reduced.

Impact on Retail Revenue

The extent to which net-metering costs have impacted Vermont utilities' revenues and retail rates varies. As described above, net-metering systems cost more than the value they provide. Additionally, net-metering reduces the utility's retail sales without reducing fixed costs; therefore, there are fewer MWhs to spread the costs over, resulting in higher retail rates for all customers. On average, in 2019, net-metering is estimated to have caused 4.7% of electric rate pressure. Table 4 below shows the impact by utility in 2019, with Green Mountain Power reporting the greatest rate impact of 5.4% and Orleans reporting just 0.2% rate impact.

Utility	Net-Metering Generation (kWh)	NM Capacity as % of Peak Load	Rate Pressure	Blended Residential Rate ($/kWh)
Barton	221,393	8%	0.9%	$0.171
BED	3,572,780	7%	0.9%	$0.138
Enosburg	1,163,131	27%	4.0%	$0.148
GMP	236,564,252	32%	5.4%	$0.169
Hardwick	1,379,903	32%	2.4%	$0.155
Hyde Park	489,768	20%	2.5%	$0.154
Jacksonville	207,738	13%	2.8%	$0.143
Johnson	755,029	22%	4.5%	$0.151
Ludlow	311,972	1%	0.5%	$0.100
Lyndonville	2,392,846	17%	3.3%	$0.139
Morrisville	1,097,932	13%	1.8%	$0.140
Northfield	725,219	14%	2.4%	$0.123

[127] Excess generation figures are based on the current net-metering convention of monthly netting of a customer's excess production (anything not used in real-time) with their consumption from the grid.

Orleans	34,885	1%	0.2%	$0.112
Stowe	1,487,958	9%	2.3%	$0.158
Swanton	1,846,971	12%	3.5%	$0.121
VEC	21,776,416	25%	3.6%	$0.160
WEC	4,059,830	23%	4.1%	$0.194
TOTAL	**278,088,023**	**28.2%**	**4.7%**	**$0.164**

Table 12: Rate pressure of net metering by utility

Going forward, the impact of net-metering should taper off as the older and most expensive systems reach the end of their 10-year adder or positive adjustor incentives and revert to the current net-metering tariffs, and new projects have lower compensation rates.

Economic Benefits of Net Metering

Early in the net-metering program, new solar projects effectively shifted the peak hour, and reduced load at the time of peaks, resulting in reduced capacity and transmission costs. However, the benefits provided by new and future net-metering projects have diminished as the peak shifts into the evening, where solar can no longer contribute. Regional capacity and transmission ("RNS") costs are allocated based on a utility's load at the time of the system peak load. As more solar comes online, and peak hours shift later in the day to hours when solar is not generating, the value of new solar has been eroded. The Department estimates that net-present value of solar over a 25-year project life to be $0.082/kWh compared the compensation paid to a new system under Net-Metering 2.3 of $0.164/kWh. Compared to other renewable resources, the cost of net-metering is significantly higher, as shown in Figure 2.

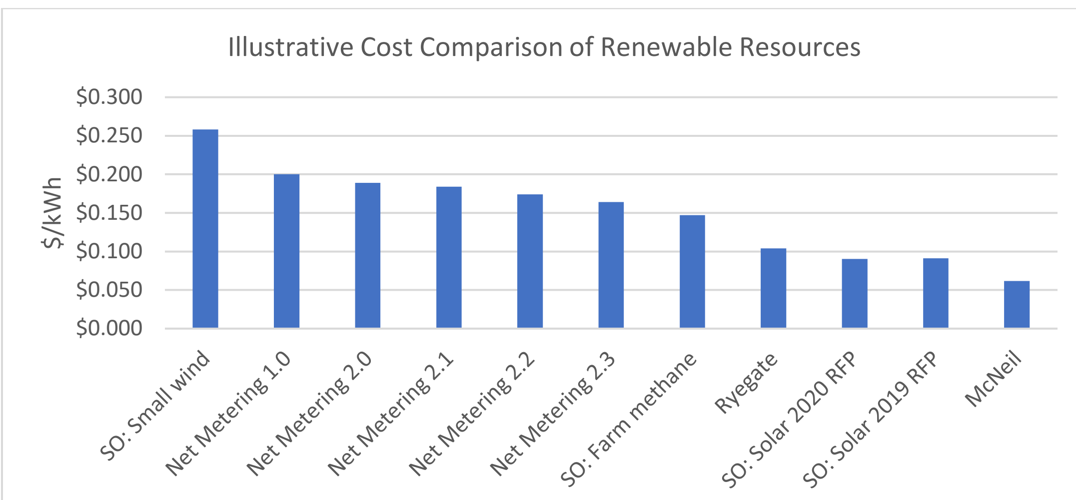


Figure 36: Cost comparison of renewable resources

It is important to note that while the costs of these resources vary greatly, so does the value of the products delivered. For example, the shape of generation from a solar net-metering project is very seasonal and much different than the shape of the generation from a farm methane generator that has a high capacity factor across all hours of the day throughout the year. It follows that the value of the generation is also different, as a farm methane project is more likely to be generating at the time of monthly peaks that occur after the sun sets. The solar Standard Offer prices have the most comparable value to net-metering but come at a much lower cost, making it clear that even with reduced compensation rates that will go into effect February 2, 2021 as a result of the Biennial Review, net-metering still does not satisfy the least-cost planning requirements of 30 V.S.A. § 218c.

Economic Development

While net-metering is one of the most expensive resources available to meet Vermont's renewable energy goals, it does employ many Vermonters. According to the 2020 Vermont Clean Energy Industry Report prepared by the Clean Energy Development Fund,[128] the number of Vermont jobs associated with renewable energy overall in 2019 was expected to be 6,035, based on pre-pandemic estimates, with approximately 2,000 of these jobs in the solar industry.[129] These are meaningful jobs that contribute to the Vermont economy.

However, it should be acknowledged that under the existing framework of net-metering incentives, these jobs come at a net cost, especially compared to alternative resources available to meet Tier II of the RES. Vermont ratepayers are effectively paying a premium to retain jobs associated with net-metering. While subsidies are ubiquitous in many job sectors, it is useful to recognize the extent of the subsidy in order to make an informed policy decision. The existing framework for net-metering provides jobs but does so in a way that results in economic distortion. To the extent that electric rates are higher than they could otherwise be, there is less disposable income and therefore less economic activity across the Vermont economy.

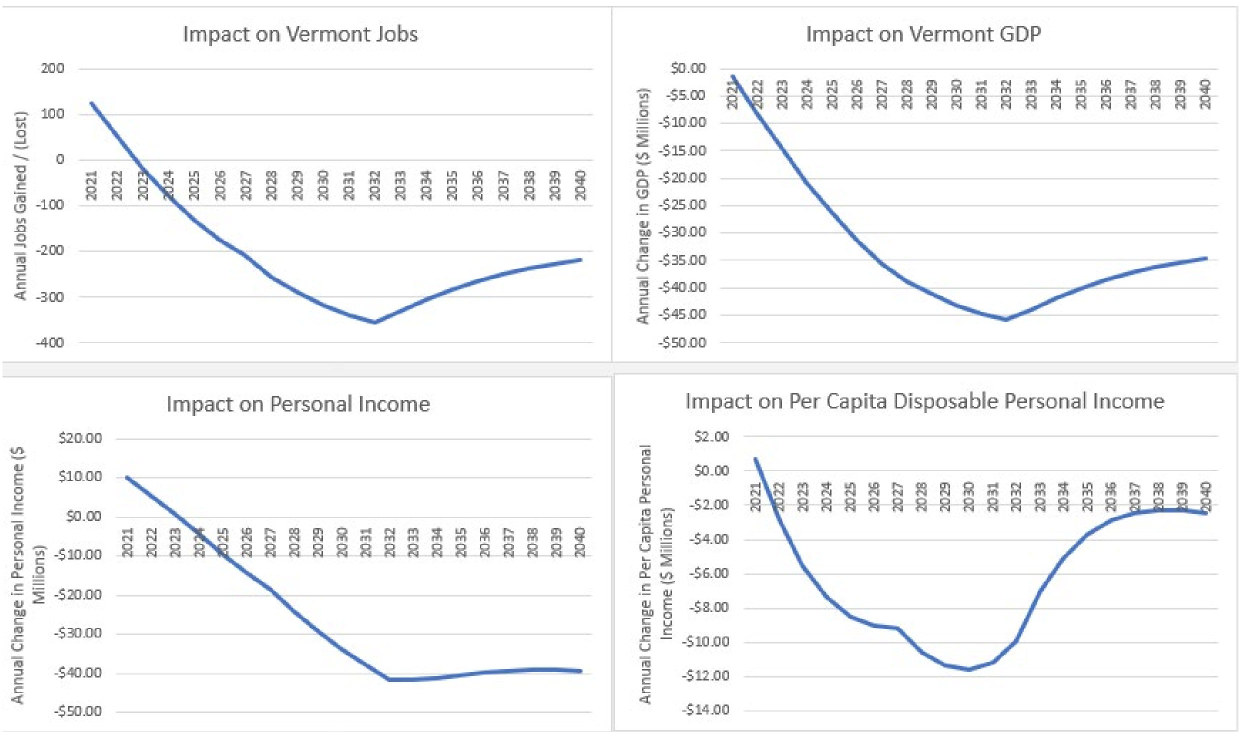
The Department worked with the Agency of Commerce and Community Development ("ACCD") to model the economic impacts of net metering, using the REMI model. The assumptions are below. In general, the construction of solar installations provides a short-term stimulus to the Vermont economy that is more than offset by an increase in electric costs that cause a long-term reduction in Vermont economic outputs. In part, this a result of the fact that most of the in-state economic benefits are associated with development of solar resources, as opposed to ongoing operations and maintenance. As more net-metering capacity is added, electric rates increase causing greater economic losses over time. The tables below set forth the assumptions and the outputs of the model.

ASSUMPTIONS	Residential Project	Group Net Metering	Total
Total Annual Installed Capacity	10 MW	10 MW	20 MW
Average Project size	7 kW	500 kW	14 kW
Average Project cost	$17,500	$750,000	$40,000,000
Average Annual Generation	8,584 kWh	788,400 kWh	28,032,000 kWh

[128] 2020 VERMONT CLEAN ENERGY INDUSTRY REPORT, *available at*: https://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/CEDF/Reports/2020%20VCEIR%20Final.pdf.

[129] Since the onset of the COVID-19 pandemic, Vermont has lost roughly 2040 clean energy jobs, equal to about 11% of the clean energy workforce. While the majority (64%) of these job losses have been in the energy efficiency sector, the pandemic has also impacted renewable energy jobs as well. Source: BWR Research, *Clean Energy Employment Initial Impacts from the COVID-19 Economic Crisis, October 2020,* available at: https://www.bwresearch.com/covid/docs/BWResearch_CleanEnergyJobsCOVID-19Memo_Oct2020.pdf.

Contribution to Vermont Economic Activity	50%	33%	44%
Annual Rate Impact of All Installed Projects	0.12%	0.16%	0.28%



Meanwhile, to the extent that keeping electric rates low is essential to encourage electrification – and therefore decarbonization – in Vermont's carbon-intensive heating and transportation sectors, current net-metering compensation is stymying progress toward Vermont's greenhouse gas goals. To meet these goals, too, Vermont will need more people working in weatherization, electric vehicles, heat pumps, and advanced wood heating systems. Decreasing compensation for net-metering need not lead to job losses in the energy sector if a concerted effort to redirect efforts and incentives toward these sectors, and to retrain the solar (and obviously the fossil fuel) workforce, is undertaken.

Environmental Impacts of Net Metering

Net-metering, like other distributed renewable generation resources eligible under Tier II of Vermont's Renewable Energy Standard (RES), reduces greenhouse gas emissions and air pollution when it displaces fossil fuel alternatives. A range of variables can affect a specific project's net emission reductions, including the project's generation capacity and lifespan and – when looking at the project from a life-cycle perspective – the amount of embodied emissions associated with the manufacturing of project components, transportation, site preparation and construction activities, and for ground mounted projects, the extent of soil disturbance and forest clearing. These environmental benefits and costs accrue to society in general and may support the greenhouse gas reduction goals codified in 10 V.S.A. § 578(a).

The Agency of Natural Resources ("ANR") may assess lifecycle (or "embodied") emissions when it evaluates particular projects during Section 248 siting proceedings before the Public Utility Commission. Otherwise, for reporting purposes, ANR calculates year-end emissions based on the overall state power supply for its emissions reporting.[130] The Department's approach to analyzing emissions reductions is to calculate the "but-for" emissions reductions attributable to specific programs. When Vermont adopted the RES in 2015, it articulated statutory requirements for renewable energy supply from resources of various sizes, types, vintages, and locations. The "distributed generation" tier of the RES (also called "Tier II") can be met with a variety of project types, as long as they are less than 5 MW, built after June 1, 2015, and connected to the Vermont grid. Net-metering, Standard Offer, utility-owned, or utility-contracted project are all eligible. Compliance is demonstrated with Renewable Energy Credits ("RECs") and under this framework, a net-metering solar system, for example, will contribute to portfolio renewability and commensurate emission reductions like any other distributed solar resource in Vermont.

Using 2016, the last year before RES was implemented, as the baseline, the Department calculated what Vermont's emissions would have been based on the electric mix in 2016, which included 35% renewables and 12.8% nuclear. To evaluate 2019 impacts, the Department then calculated what the emissions would have been with 2019 emissions factors applied to the 2016 energy mix. As a result of RES, the electric mix is much different now, with 66% renewables and 28% nuclear. The Department attributes the 31% increase in renewables directly to the RES; in 2019 that corresponded to around 552,000 tons of carbon. Because utilities were required to meet a 2019 Tier II obligation of 2.2% of sales (a carveout of a broader "Tier I" obligation of 55% of sales), and net-metering comprised about 53% of Tier II in 2019, the approximate amount of emissions reductions that can generally be attributed to net-metering in 2019 is approximately 8,862 tons of carbon.[131]

Tier II-eligible resources such as net-metering are "behind the meter" to the regional system operator, ISO-NE: they look like a reduction in load, similar to energy efficiency, and reduce the energy products utilities need to procure from the regional markets. Any utility purchases that do not include environmental attributes, or RECs for renewable resources, are known as "system mix," and are assigned the emissions characteristics associated with that mix. Below, Figure 3[132] from ISO-NE shows the proportion of regional electric energy generation by resource type:

[130] https://dec.vermont.gov/air-quality/climate-change

[131] Statewide, utilities overcomplied in 2019 with Tier 1 requirements, retiring RECs equal to 66% of sales. Tier II RECs comprised 2/66 – or 3% - of that (not 2.2% overall statewide as three utilities, Burlington Electric Department, Washington Electric Cooperative, and Swanton Electric, have 100% renewable portfolios and are thus exempt from Tier II requirements). And net-metering RECs comprised 53% of retired Tier II RECs.

[132] https://www.iso-ne.com/about/key-stats/resource-mix/

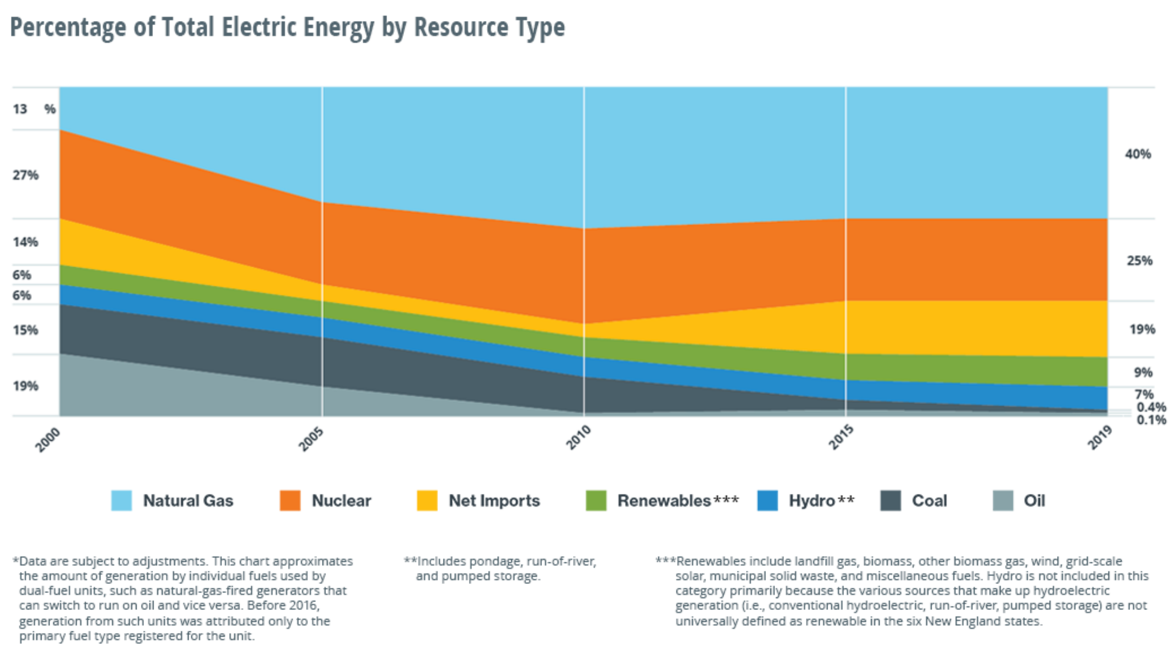


Figure 37: ISO-NE Electric Energy Generation

One takeaway from the chart is that accelerating clean and renewable energy requirements by New England states have led, at least in part, to nearly all the coal plants retiring and the oil plants that remain operate as capacity resources that generate limited energy; the proportion of market-facing renewables is growing, but load (real-time demand not being met with output from small renewables like net-metering, as well as efficiency) is still largely met with natural gas and nuclear generation at present. The system mix corresponds to the following changing emissions profile for the New England region, with decreases in air pollutants corresponding to fossil plant retirements as shown in Figure 4.[133]

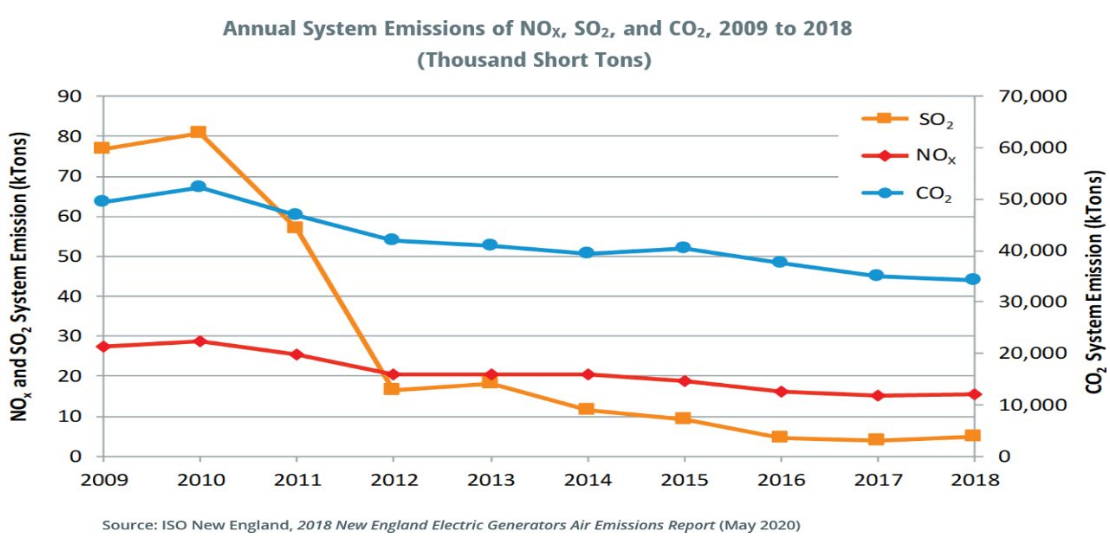


Figure 38: Historical ISO-NE Generators Air Emissions

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[133] https://www.iso-ne.com/system-planning/system-plans-studies/emissions/

As discussed above, in order to meet Vermont's RES requirements, utilities will need approximately 25-27 MW per year of distributed, Tier II-eligible renewable resources to be deployed. A MW of solar, for instance, generated by any one of these resource types contributes equally to meeting the RES requirements (though at widely varying costs to ratepayers, net-metering resources being the most expensive). Similarly, a MWh of solar from any of these resource types contributes equally to offsetting other energy purchases with a particular emissions profile in a particular day or hour. And while the Department evaluates the emissions impacts of the RES on a net annual basis, it's important to recognize that actual emissions from regional generation can vary widely depending on the day or hour, with the regional system emitting the most in the coldest days of winter (when solar, regardless of resource type, is not much help). ISO-NE demonstrates this in the Figure 5[134] below:

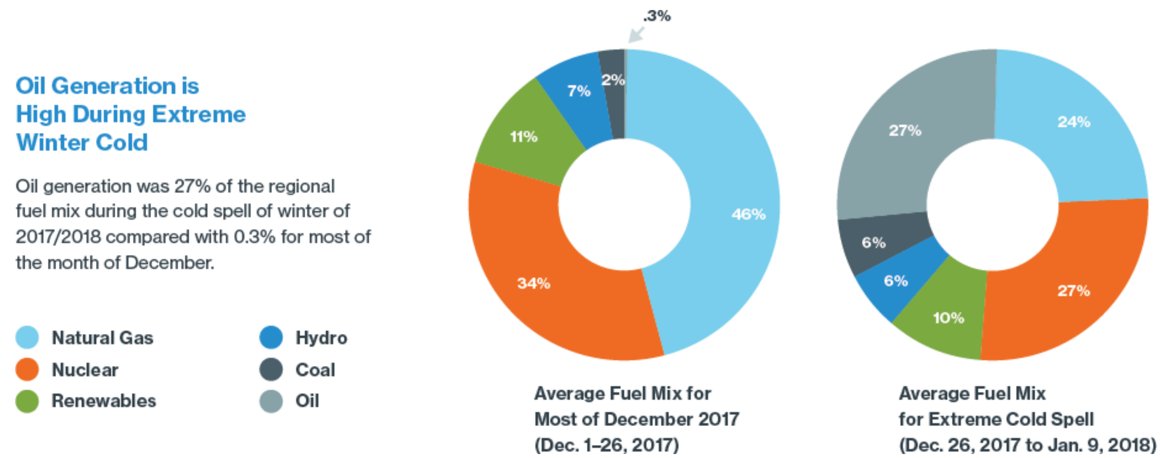

Figure 39: ISO-NE Fuel Mix During Normal and Extreme Winter Events

The Department has articulated concerns with the ability of net-metering customers to export most of their production in sunnier months, to monetize that excess, and to apply it to their bills in darker months elsewhere in this report and in Public Utility Commission Case No. 19-0855-INV, the net-metering rulemaking. This convention is beneficial to individual customers but adds stress to the grid and costs to other ratepayers, especially as distributed solar penetration increases. Like net-metering, the RES allows utilities to "net" their electricity sales with RECs that may be disconnected from real-time load. Some jurisdictions – notably Massachusetts – are taking the first steps toward attempting to incentivize renewable production when (if not necessarily where) it's needed with the adoption of a Clean Peak Standard. The Clean Peak Standard assigns higher value to generation correlated with peak loud hours. This change to their Renewable Portfolio Standard was only just recently enacted, and the Department looks forward to understanding its successes and challenges as it unfolds.[135]

In addition to environmental benefits from emissions reductions, net-metering - again like other distributed renewable generation resources eligible under Tier II of Vermont's RES) – is not without environmental costs. Construction of net-metering systems, like any construction project that uses fuel-burning equipment or generates dust, creates temporary air emissions. Also, all forms of energy development in Vermont have a footprint on the landscape. In some cases that footprint is on rooftops, parking lots, landfills, or other already developed sites; in other instances that footprint is on an

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[134] https://www.iso-ne.com/about/key-stats/resource-mix/

[135] https://www.mass.gov/info-details/clean-peak-energy-standard-guidelines

undeveloped landscape or 'greenfield' site. Conversion of land from natural conditions, as can happen with net-metering systems on greenfields, can result in loss of or damage to natural landscapes and ecological function. These natural landscapes provide numerous environmental benefits to Vermonters, including clean air and water, crop pollination, carbon sequestration, flood protection, and fish and wildlife habitat.

The Public Utility Commission's Net-Metering Rule (Rule 5.100) incents, and in certain cases requires, the siting of net-metering systems on one of 9 types of "preferred sites." One goal of the preferred site framework is to promote siting of net-metering systems on the already developed landscape. Since July 1, 2017, the effective date of the current Net-Metering Rule, 26 applications have been filed for net-metering systems at gravel pits and quarries, 6 applications have been filed for net-metering systems at Agency of Natural Resources (ANR)-certified sanitary landfills, and one application has been filed for a net-metering system at an ANR-certified brownfield. Combined, these systems provide 11.55 MW in capacity. Development of net-metering systems at gravel pits, quarries, landfills, and brownfields can hasten their reclamation, facilitate environmental investigation and remediation activities, and inject income to offset maintenance and site management costs, which are all beneficial outcomes. Though significant, development at these sites represents only 20 percent of all net-metering applications filed between July 1, 2017 and October 31, 2020 that were comprehensively reviewed by ANR (ANR generally does not review net-metering registrations and reviews applications for net-metering systems under 50 kW on a case-by-case basis). There have been no applications for net-metering systems for the Superfund preferred site type.

Of the 163 net-metering applications filed between July 1, 2017 and October 31, 2020 that required comprehensive review by ANR, over two-thirds were for systems designated as preferred in municipal plans or with joint letters of support (50%) or were located on the same parcel as or directly adjacent to the majority offtaker (23%). These are the two preferred site types that allow for greenfield development, and over half of these projects involved some forest clearing and conversion. 30 percent of them involved over 1 acre of forest conversion, 17 percent involved more than 3 acres of forest conversion, and 6 percent involved more than 6 acres of forest conversion. Conversion of forests for net-metering displaces the carbon sequestration benefits provided by forests.

Net-Metering and the Grid

Infrastructure Impact of Net Metering

Under the best-case scenario, net-metered and other distributed energy resources ("DERs") can minimize infrastructure needed to support the grid or import energy from more distant locations, and reduce line losses associated with such imports.[136] That's one of the reasons why the Vermont System

[136] In Case No. 19-0855-RULE, the Department included a line loss value of 8%, consistent with the Avoided Energy Supply Costs study and further explored by the Commission in Case No. 19-0397-PET. The line losses calculated in that proceeding were specific to energy efficiency. The Department expects that transmission losses would be similar for net-metering resources as they are considered behind-the-meter resources from a regional perspective. It is doubtful that the value for distribution losses would be appropriate, however. For energy efficiency, there is no excess generation exported to the grid, as there is under the net metering structure. This generation in itself can result in losses, particularly in constrained areas with significant amounts of generation on the distribution

Planning Committee ("VSPC") evaluates distributed generation – alongside energy efficiency and demand response – as an alternative to poles-and-wires solutions when it assesses potential solutions to grid reliability concerns. In the past, many of these concerns were driven by load growth. And while energy efficiency and net metering have effectively flattened overall load growth in Vermont, the challenge of strategically deploying these resources in time and space to match specific areas or times of higher loads grows. Since nearly all the net-metering in Vermont is "uncontrolled" solar – in that it's not time-shifted with storage to match demand – its output coincides with the daily and seasonal arc of the sun. Customer demand for energy in the dark of night and of winter is therefore not being served with net-metered resources, a trend growing with penetration of solar and increasingly eroding its infrastructure-deferral benefits.

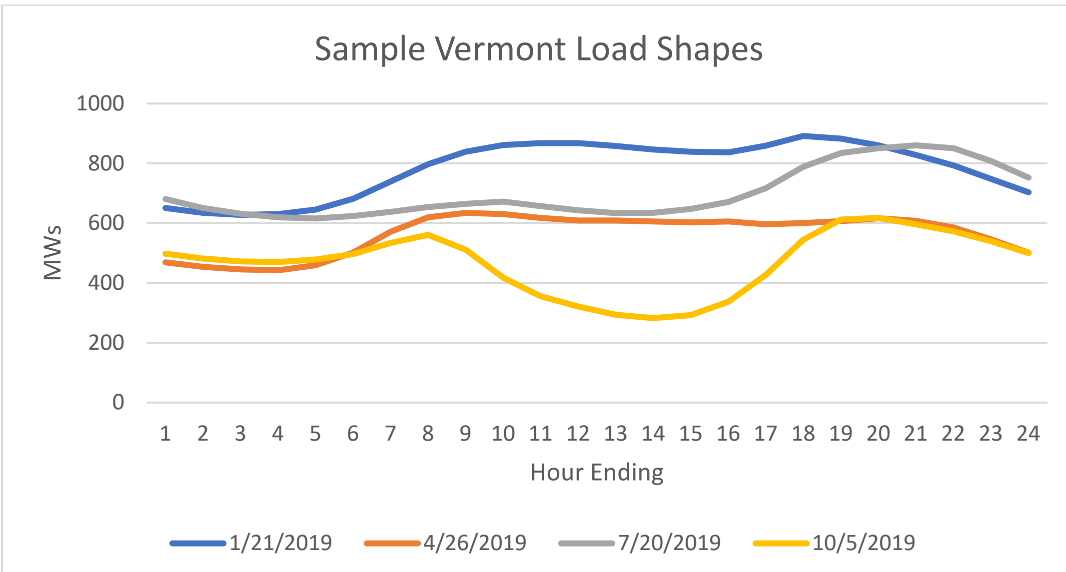

Figure 40: Sample of Vermont load shapes throughout the year [137]

In fact, there's a growing likelihood that net-metering will necessitate – rather than reduce – the need for additional electric infrastructure. This is directly related to the large amount of net-metering (250 MW) and other distributed solar (another 131 MW) in Vermont compared to load (~1,000 MW), particularly on a localized basis, where solar penetration can be so high that at times, generation exceeds load at the distribution transformer. When that happens, a number of reliability issues and potential costs can arise. According to IEEE,

> *One of the more frequent issues utilities will have to address is the potential for a large amount of substation transformer backfeed stemming from reverse power flow on distribution circuits. Excess PV output on the distribution system during periods of minimum daytime loading causes a number of issues for utility planning and operation, such as temporary overvoltage conditions, the need for protection schemes*

system. Consequently, there would need to be further thought as to whether line losses should appropriately considered a positive or negative value with respect to net metering.

[137] Source: VELCO

modifications, and equipment failure from an increase in voltage regulation operations.[138]

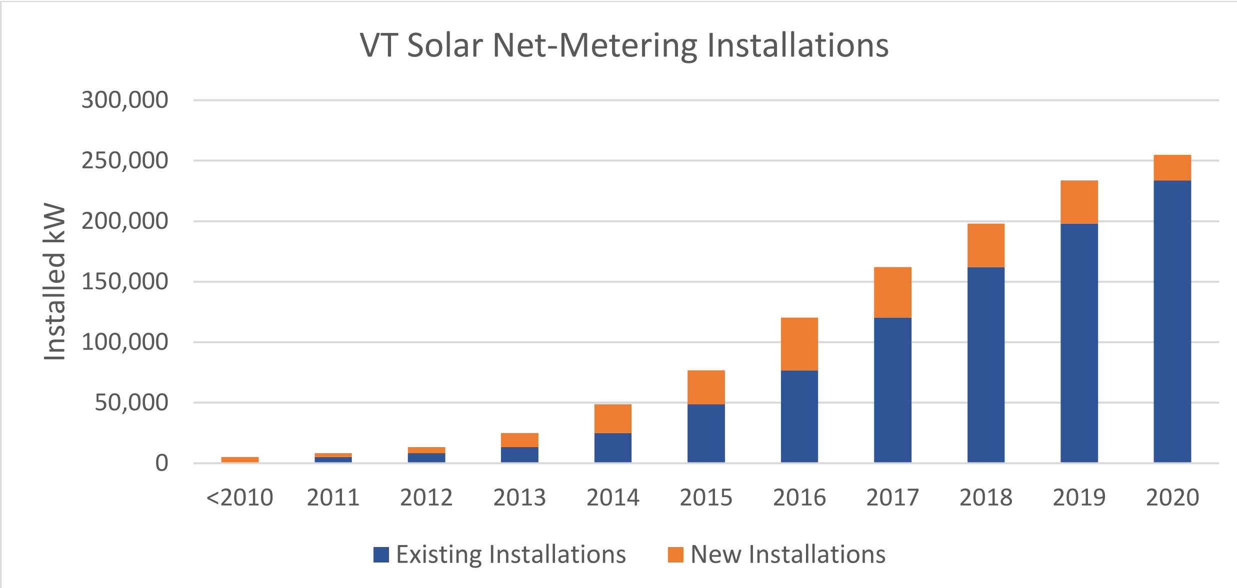

Figure 41: Vermont Solar Net-Metering Installations by Year [139]

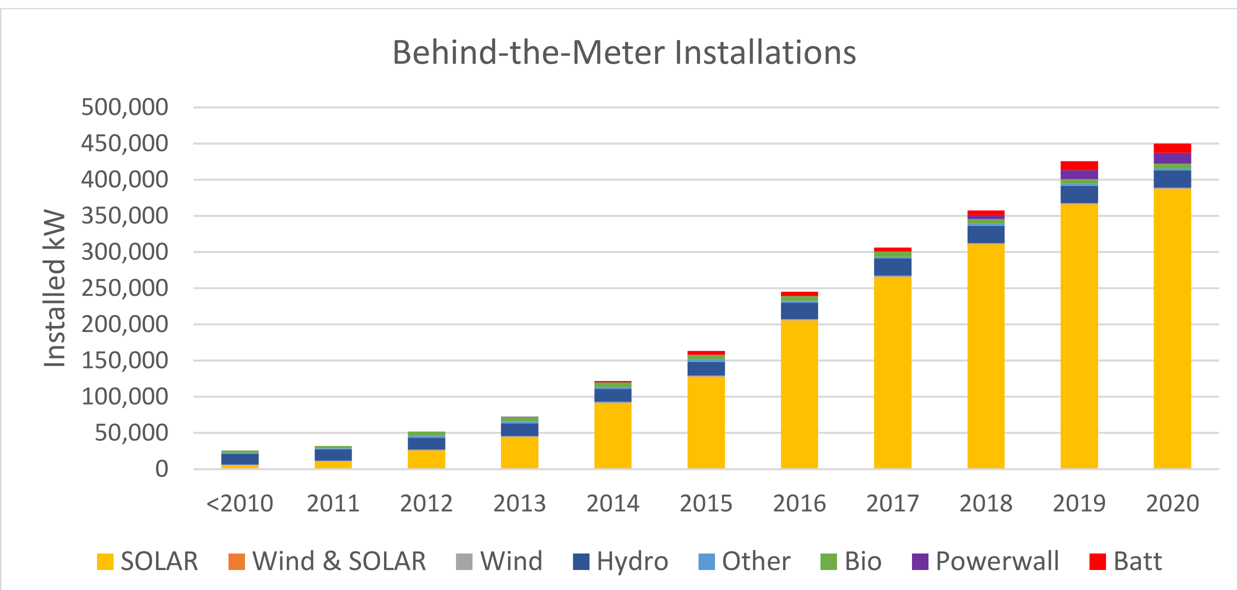

Figure 42: Vermont Behind-the-Meter Installations by Technology [140]

The blunt-edged tool to address so-called overgeneration is to upsize substation transformers – to the tune of several million dollars apiece. The long-standing regulatory principle of assigning costs to cost

[138] https://ieeexplore.ieee.org/document/8274081
[139] Derived from utility monthly DG resource surveys to ISO-NE and includes data for GMP through 10/31/20, VEC through 8/31/20, Stowe through 10/31/20, and BED and WEC through 8/30/20.
[140] Ibid

causers, in this case the net-metering systems, breaks down when the context changes from the next incremental individual system to the cumulative effect of tens or hundreds of existing net-metering generators that eat away at the remaining headroom on a substation transformer (or the desire to accommodate the next dozen or hundred net-metering customers) – although new approaches of distributing costs to interconnected DERs are emerging.[141]

This situation is not just hypothetical in Vermont. In Green Mountain Power ("GMP") territory, for example, at least 14 of 164 substations are approaching these types of limits. For at least one type of upgrade – Transmission Ground Fault Overvoltage or "TGFOV" – the Public Utility Commission has approved a methodology for addressing a potential grid liability by allowing GMP to collect an additional fee from interconnecting net-metering resources that goes into a fund used to pay for mitigating upgrades.[142] The map below shows circuits in GMP service territory, color-coded according to "room" on the substation transformer for additional generation. Projects proposed in areas outlined in gray are subject to the TGFOV fee; and the key explains limitations in other shaded areas (e.g., red circuits connect to the most highly generation-constrained substations).[143]

[141] https://www.nrel.gov/dgic/interconnection-insights-2018-08-31.html

[142] See Case No. 19-0441-TF

[143] GMP Solar Map, available at https://www.arcgis.com/apps/webappviewer/index.html?id=4eaec2b58c4c4820b24c408a95ee8956, accessed 11/27/20. Red corresponds to 14 substations, yellow to 6 substations, and gray to 46 substations (which may also have secondary red or yellow limitations, TGFOV being the most limiting condition). Burlington Electric Department has a similar map available here: http://burlingtonvt.maps.arcgis.com/apps/Embed/index.html?webmap=bb1b9156d8294e308ecfe803131e8c00&extent=-73.2731,44.4574,-73.1094,44.5091&zoom=true&scale=true&legend=true&disable_scroll=false.

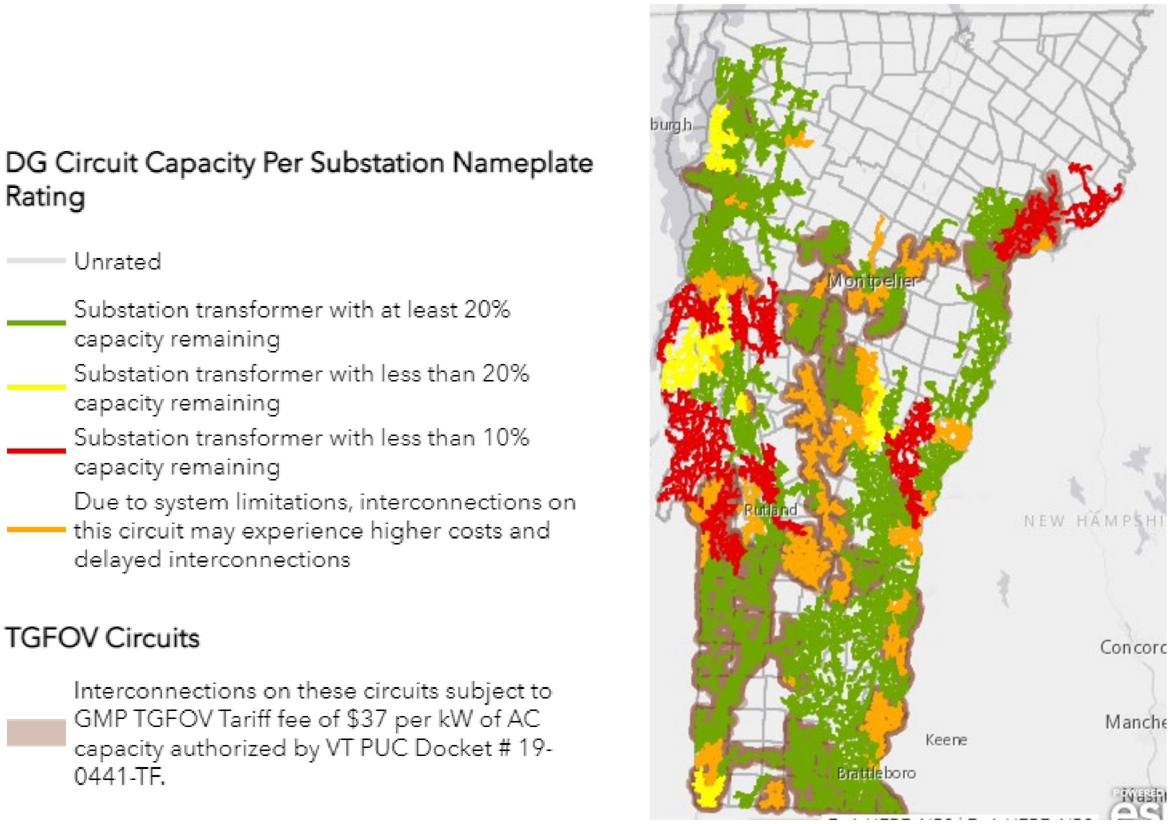

Figure 43: Green Mountain Power DG Circuit Capacity

One of the main challenges for Vermont policymakers, regulators, and utilities to address as net-metering (and other renewables programs) evolve is how to address such constrained areas in the myriad renewables policies, programs, regulations, and tariffs, from net-metering to transmission planning and interconnection requirements. This is playing out right now in the debate over whether and how to allow additional, larger-scale net-metering resources to interconnect in the so-called Sheffield Highgate Export Interface ("SHEI") area of Vermont's transmission system.[144] This area of northern Vermont has ten times more generation than load, resulting in curtailment of generation – including ratepayer-funded generation – about 20% of the time (and every additional renewable generation source exacerbates the curtailment).[145] Similarly, because distributed renewable energy has also boomed in other New England states – with whom we share a transmission grid (and related expenses) to transport wholesale generation across the region – these questions are starting to matter to the region's transmission grid planner and operator, ISO-NE, too.

As solar penetration has increased across the region, resulting load patterns reflect the "bite" solar has taken out of midday electricity demand – meaning once the sun sets, demand that had been served (and "masked") by distributed solar suddenly "reappears" to grid operators and must be served by other types of resources. This phenomenon, first observed in California, is commonly known as the "duck

[144] See Case No. 20-3304-PET.
[145] https://www.vermontspc.com/grid-planning/shei-info.

curve."[146] In the screen capture of ISO-NE's dashboard below (taken 11/27/20), the duck curve is apparent.

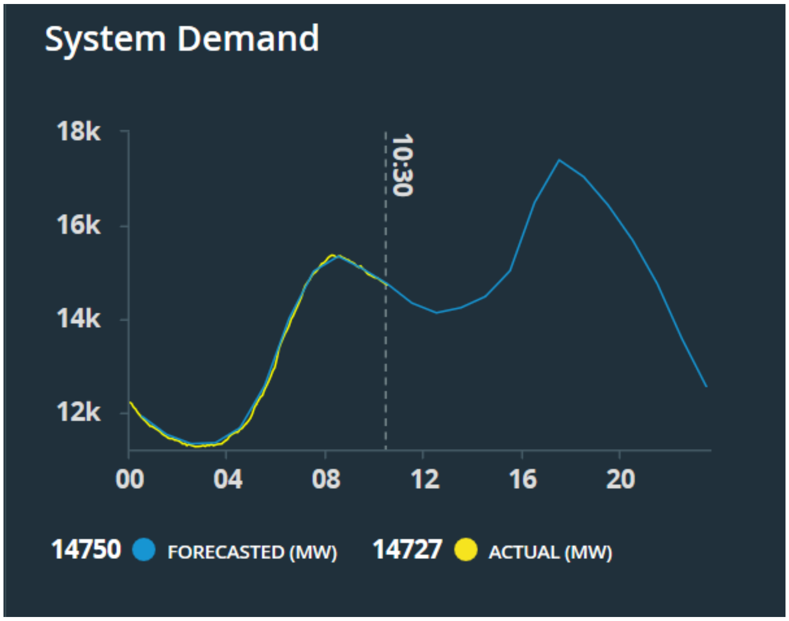

Figure 44: ISO-NE Energy Dashboard [147]

A decade or so ago, distributed solar had just started eating into mid-day peak demand in the region. ISO-NE recently analyzed solar penetration and demand from 2012 to 2015, in order to estimate demand reductions from each increment of solar installed going forward. The chart below shows estimated peak reductions per MW of installed solar and demonstrates the diminishing returns as penetration increases. This assumes no change in the demand profile of load or the generation profile of solar – both of which are, however, becoming increasingly likely as flexible load and energy storage technologies rapidly evolve and come down in cost.

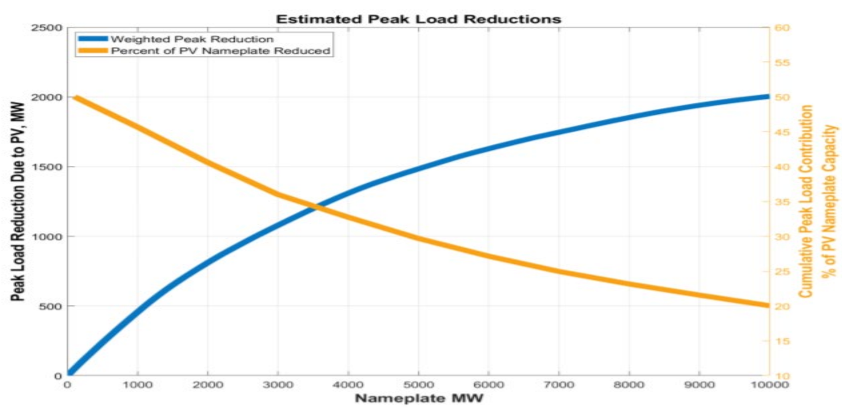

Figure 45: ISO-NE Peak Load Reductions Due to Solar [148]

[146] https://www.nrel.gov/news/program/2018/10-years-duck-curve.html
[147] https://www.iso-ne.com/ (retrieved 12/22/20 at 10:35 a.m.)
[148] See https://www.iso-ne.com/static-assets/documents/2020/03/3_peak_load_reductions_update.pdf

ISO-NE has recently launched its "Planning for the Clean Energy Transition Initiative," in recognition of the growing penetration of distributed solar and other DERs and the commensurate complexities in planning a reliable transmission system around potentially millions of resources it cannot see or control. ISO-NE anticipates incorporating additional study conditions beyond peak demand, including the intersection of high/low demand with high/low solar production, as it begins to observe extremely low midday net loads. It is also undertaking a pilot study to evaluate tradeoffs between flexibility and reliability, including risks of fleets of DERs tripping offline in response to transmission faults, and other novel conditions related to high penetrations of inverter-based resources, including grid stability and inertia.[149] The study will look at transmission system investments (more costly to ratepayers) alongside operational measures and policy changes (less costly to ratepayers), and will assume "business as usual" assumptions about DER deployment and behavior in the absence of proof or at least strong reassurance to the contrary.[150]

To give such assurance, as well as to enable growing penetrations of distributed generation in Vermont, the Department and many others are examining more precise, less expensive ways to address the issue of overgeneration than upsizing substation transformers. These all focus on better orchestration of generation and load and range from directing generation toward or away from particular locations to time-shifting generation or load with storage to maximizing the abilities of "smart inverters" to curtail excess generation. The key to many of these solutions is implementation of rate signals that direct a DER, including a load, to alter its behavior in response to a price signal associated with a grid requirement. A complementary tool is direct control of DERs by a utility (or third party on behalf of a utility), though given the proliferation of DERs, this is likely going to require investment in real-time situational awareness, monitoring, and control tools, some of which are not yet commercially available. Over the past year, the Department undertook a Rate Design Initiative to explore some of these concepts.[151] An ad-hoc subcommittee of the Vermont Systems Planning Committee is also in the process of examining how flexible loads, energy storage, and curtailment can be used – singly or in concert – to enable additional distributed generation on a constrained circuit.[152] The Department's proposal to reform net-metering compensation to value production consumed on-site higher than production exported beyond the customer meter would also have the effect of mitigating overgeneration and related infrastructure costs.[153]

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[149] ISO-NE has already asked distribution utilities throughout New England to require specific inverter settings for interconnecting solar generators to allow them to ride through grid perturbations. See https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwi-7q_N7KPtAhVrVzABHYoSAz8QFjABegQIARAC&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2018%2F02%2Fa2_implementation_of_revised_ieee_standard_1547_presentation.pdf&usg=AOvVaw1XF4tUehcQv9wj9zRgdIRg.

[150] https://www.iso-ne.com/static-assets/documents/2020/11/a6_transmission_planning_for_the_clean_energy_transition_updated_assumptions_and_pilot_study_proposal.pdf

[151] https://publicservice.vermont.gov/content/rate-design-initiative

[152] https://www.vermontspc.com/vspc-at-work/subcommittees

[153] See Case No. 19-0855-RULE, 11/1/19 *Department of Public Service Report on Public Utility Commission Net-Metering Information Requests*

Benefits of Connecting to Distribution System

Net metering, as defined in statute, only works when the customer is connected to and benefiting from their electric utility's distribution system:

> ***30 V.S.A. 8002(15):*** *"Net metering" means measuring the difference between the electricity supplied to a customer and the electricity fed back by the customer's net metering system during the customer's billing period.*

As electric customers are generally subject to a monthly billing period, the "netting" generally takes place over a month. Under the current net-metering rule,[154] small systems located at customer premises generally serve load in real time (i.e. "spin the meter backward), and either send "excess" kilowatt-hours ("kWh") back into the grid or pull additional electricity from the grid to serve demand that is higher than (or needed at a different time than) production. Customer electric meters can measure both of these flows, and at the end of the month, utility billing departments net excess kWh with utility-delivered kWh. If there are net kWh delivered, they are billed at the residential or other applicable rate. If there are excess kWh generated, those are credited to the customer at the applicable base rate (for most customers, this will be a blend of the statewide residential rates).

Separately, "gross" kWh produced by the net-metering system – measured by a separate production meter – are multiplied by applicable adjustors, which can either be positive or negative depending on the system's size and siting. The resulting credit (or debit) is also applied on customer bills. Credits cannot be used toward "fixed charges" such as the customer charge,[155] but they can roll over for a 12-month period, which enables customers to carry over excess production from summer to winter months *on paper*. For group net-metering systems – often larger, 150 kW or 500 kW – more often than not, all production is considered to be excess and is generally applied as a credit to all subscribers of the system, who can be located anywhere in a utility service territory.

Aside from relying entirely on the distribution system for the mechanics of net metering, net-metering customers are also reliant on the distribution system to serve load that their net-metering systems are unable to meet: in real time, throughout the day, at night, and over the course of the year. If a customer wanted to rely entirely upon their own distributed generation, they would need to add battery storage and size their overall system to meet their power needs throughout the year. Utilities are obliged to serve their customers, safely and reliably, and must ensure they have resources to meet and serve customer demand regardless of the existence and behavior of that customer's net-metering system.

Group systems generally send all of their production directly to the distribution grid. None of it is offsetting on-site load, and utilities therefore treat it all as "excess," allocating monetary credits to subscribers based on total production multiplied by the applicable base rate and by the applicable adjustors. Customers of these systems are entirely dependent on the grid and utility to supply their

[154] Net-Metering Rule Effective 07-01-2017 - 5100-PUC-nm-effective-07-01-2017_0.pdf

[155] Systems installed under pre-2017 rules were allowed to apply credits toward fixed charges and continue to be able to do so for ten years from their commissioning date, at which point they revert to net-metering tariffs in place at that time.

electricity demand. Without the net-metering construct, these customers would not be able to associate the virtual net-metering system with their home or business accounts.

Net-metering customers in Vermont participate in the program for a variety of reasons, from reducing their electric bill to participating in the state's renewable expansion and decarbonization. Because the state's electricity mix is highly renewable overall (66%, and 100% in some utility territories), and the greatest opportunity reduce emissions is in the transportation and heating sectors (including by electrification), it may be more impactful at this point in time for customers to instead invest in electric vehicles and heat pumps – and for policymakers to work to limit the rate impacts from net-metering in order to encourage use of electricity for these purposes.

Costs and Benefits of Reliability and Supply Diversification

Electric grid reliability is governed by specific requirements and standards, at both the bulk and distribution system levels – and net metering systems have potential impacts, both positive and negative, on both. The primary reliability authority is the Federal Energy Regulatory Commission ("FERC"): "All users, owners and operators of the bulk power system must comply with the mandatory Reliability Standards developed by the electric reliability organization and approved by FERC."[156] ISO-NE, Vermont Electric Power Corporation (VELCO, Vermont's transmission system operator), and others subject to this definition must comply with reliability standards set by the North American Electric Reliability Corporation ("NERC"),[157] and the Northeast Power Coordinating Council ("NPCC").[158] Distribution utilities are further subject to regulation by the Commission, and are required to file Service Quality and Reliability and Reliability Plans, with reporting on metrics such as the frequency and duration of outages.

At each of these levels, distributed energy resources such as net-metered solar are bubbling up as an area for greater attention and focus. NPCC, for instance, recently released the second version of its publication, *NPCC DER Guidance Document, Distributed Energy Resource (DER) Considerations to Optimize and Enhance System Resilience and Reliability*.[159] These two concepts – resilience and reliability – are often used interchangeably, but the Department believes careful usage and definition of each term is essential to ensuring that stakeholders discussing impacts of a resource such as net-metering on reliability, or resiliency, are not talking past each other. Reliability is a core tenet of Vermont energy policy:

> *30 V.S.A. § 202a: It is the general policy of the State of Vermont:*
>
> *(1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate**, reliable**, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.*

[156] https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf, p. 39.
[157] https://www.ferc.gov/industries-data/electric/industry-activities/nerc-standards
[158] https://www.npcc.org/program-areas/standards-and-criteria/regional-standards
[159] https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/der-forum/2020/der-v2-11-20-2020.pdf

It is also a core tenet of the concept of "energy assurance," as articulated in Vermont's Energy Assurance Plan (itself part of the state's Emergency Operations Plan) where energy assurance is defined as:

> "*The ability to obtain, on an acceptably **reliable** basis, in an economically viable manner, without significant impacts due to Energy Supply Disruption Event(s), or the potential for such events, sufficient supplies of the energy inputs necessary to satisfy Residential, Commercial, Governmental, and non-governmental requirements for Transportation, Heating (space and process heat), and Electrical Generation."*[160]

In other words, reliability is a strictly defined term subject to specific standards, metrics, reporting, enforcement, and penalties. It is, foundationally, about avoiding "loss of load," or power outages, both in number and duration, during day-to-day operations, with metrics focusing on reliability performance over a specified period of time. NERC defines a reliable bulk power system as, "one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity."[161] The concept includes both *resource adequacy* – i.e. sufficient supply – and *security*, or the ability to withstand sudden, unexpected disturbances, either natural or man-made.

Resilience (or resiliency), on the other hand, is more of a term of art, subject to a variety of proposed definitions, with an evolving landscape of potential metrics, but without specific regulatory "teeth." FERC has proposed the following definition of resilience, which has been adopted by NERC: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[162] Resilience, unlike reliability, is usually thought of in terms of a specific, low-probability, high-impact event. And without imposition of a measurement or valuation framework, it is not particularly meaningful to describe a grid as resilient or to describe a resource as providing grid resilience. The following graphic from the Pacific Northwest National Laboratory attempts to illustrate the resiliency vs. reliability domains:

160 https://publicservice.vermont.gov/sites/dps/files/documents/VT%20Energy%20Assurance%20Plan%20August%202013.pdf

161 https://www.nerc.com/AboutNERC/Documents/NERC FAQs AUG13.pdf

162 https://elibrary.ferc.gov/eLibrary/#, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, para. 14, FERC Dkt. No. AD18-7-000 (Jan. 8, 2018). Pp. 12-13. Accessed 12/5/20.

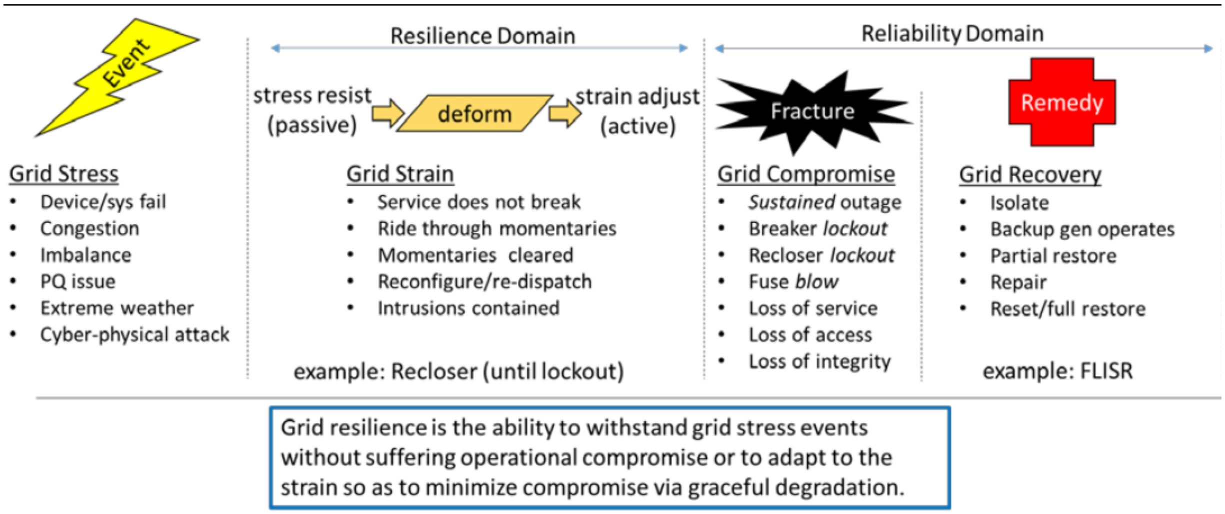

Figure 46: Pacific Northwest National Laboratory resiliency versus reliability [163]

At the Lawrence Berkeley National Laboratory, researcher Joe Eto proposes the following as a lens through which to understand how resilience differs from reliability:

	Reliability	Resilience
Common features/ characteristics	Routine, expected, normally localized, shorter duration interruptions of electric service Larger events will make it into the local headlines	Infrequent, unexpected, widespread/long duration power interruptions, often with significant corollary impacts Almost always "event" based Always national headline worthy
Metrics	Well-established, annualized (SAIDI, SAIFI, MAIFI), with provisions for "major events" Rarely include non-electricity impacts	Familiar, but non-standardized, and generally event-based (number of customers affected; hours without electric service) Routinely also include non-electricity impacts (e.g., costs to firms; health and safety impacts)
Actions to improve	1. Plan and prepare; 2. Manage and endure event(s); 3. Recover and restore; and 4. Assess, learn, and update plan.	No qualitative difference But generally larger in scope/cost (see next slide)

Figure 47: Reliability versus resilience [164]

And has also proposed the following as potential metrics for measuring the impacts of resilience investments:

[163] https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability.pdf
[164] https://eta-publications.lbl.gov/sites/default/files/5_-_eto_reliability_and_resilience_based_planning_4.pdf

GMLC Resilience Metrics	Data Requirements
Cumulative customer-hours of outages	customer interruption duration (hours)
Cumulative customer energy demand not served	total kVA of load interrupted
Avg (or %) customers experiencing an outage during a specified time period	total kVA of load served
Cumulative critical customer-hours of outages	critical customer interruption duration
Critical customer energy demand not served	total kVA of load interrupted for critical customers
Avg (or %) of critical loads that experience an outage	total kVA of load severed to critical customers
Time to recovery	
Cost of recovery	
Loss of utility revenue	outage cost for utility ($)
Cost of grid damages (e.g., repair or replace lines, transformers)	total cost of equipment repair
Avoided outage cost	total kVA of interrupted load avoided $ / kVA
Critical services without power	number of critical services without power total number of critical services
Critical services without power after backup fails	total number of critical services with backup power duration of backup power for critical services
Loss of assets and perishables	
Business interruption costs	avg business losses per day (other than utility)
Impact on GMP or GRP	
Key production facilities w/o power	total number of key production facilities w/o power (how is this different from total kVA interrupted for critical customers?)
Key military facilities w/o power	total number of military facilities w/o power (same comment as above)

Figure 48: Grid Modernization Lab Consortium Resilience Metrics [165]

While utilities are required to provide every customer with reliable electric supply, there are instances where customers may make investments (with or without utility involvement) to enhance their individual reliability (or, potentially, resiliency). Customer-sited generators, or batteries – such as those deployed under Green Mountain Power's Powerwall and Bring Your Own Device tariffs, for instance – are one such example.[166] In those programs, customers pay for the enhanced personal grid reliability offered by the battery storage, while all the utility's customers both pay for and gain benefit from the other values provided by the storage in the aggregate, such as reducing peak-related charges.

Net-metering, as a financial mechanism for incentivizing development of renewable energy systems by crediting customer bills for the production from those systems, does not have any defined relationship with the concepts of either reliability or resiliency. Small, distributed solar – the predominant type of system being incentivized with the net-metering program – potentially impacts both, in positive as well as negative ways. Distributed solar on its own is not going to keep customers' lights on if the grid goes down, unless additional investments in storage and protections are made in specific areas of the grid to benefit specific customers – such as in the case of those customer-sited battery storage programs or community microgrids. A customer – or group of customers, in the case of a microgrid – with a battery storage system may be able to continue to power specific loads for 1-2 days, longer if their "island" includes a solar system. In that sense, many net-metered systems can be considered to be a *precursor* to enhanced reliability (or, potentially, resiliency).

In terms of individual generation projects, impacts on grid reliability are reviewed through the interconnection process, which is required for a system to obtain a Certificate of Public Good and to interconnect to the grid.[167] A system might be required to install specific protective equipment in order

[165] Ibid.
[166] https://greenmountainpower.com/rebates-programs/home-energy-storage/
[167] https://Commission.vermont.gov/document/commission-rule-5500-electric-generation-interconnection-procedures

to demonstrate it won't adversely impact system stability and reliability – though small, customer-sited net-metered systems are unlikely to trigger such requirements. However, like the aggregated impacts on grid infrastructure discussed earlier, the cumulative impact of many small systems can eventually impact grid reliability in ways that are impossible to associate with any one individual system.

Another way net-metered systems act as a precursor to enhanced grid reliability lies in the inverters tying these systems to the grid. What is currently viewed as a reliability liability from the growing fleet of these resources – the potential for a fault on the grid to trip the fleet offline like so many dominoes, taking a chunk of supply offline all at once – can be mitigated with upgrades to inverter equipment and settings. Most net-metered solar in Vermont is tied to the grid with inverters (converting DC production to AC supply aligned with the grid) that signal the system to trip offline if they sense a grid perturbance. This is a safety function – if the power fails and a net-metered system is still energized, lineworkers coming into contact with the facility could get electrocuted. To encourage systems to stay offline in conditions shy of power outages, ISO-NE has issued a so-called "Source Requirements Document" ("SRD"), specifying inverter settings during the interconnection process to ensure inverters ride through grid perturbances.[168] Most – if not all – utilities in Vermont require interconnecting customers to follow the SRD specifications. As advanced inverters enter the marketplace, distributed solar employing these inverters (new systems and replacements for existing systems at the end of inverter life) hold potential to become a newfound source of grid support services, particularly if interconnection standards encourage them to do so.[169]

Other ways to harness the net-metered solar fleet to enhance (or not degrade) grid reliability include coupling systems with on-site or upstream storage to firm production or to store-and-release production to better match loads; encouraging system sizing to match on-site or area load; and implementing real-time grid visibility tools to enable situational awareness by system operators. These actions all require additional investment, however, and the Department would not support requiring ratepayers who already pay twice as much for net-metered solar as they would for other RES-eligible solar to also have to bear costs associated with better integrating this fleet of resources in order to maintain or enhance grid reliability. This is especially true when there are many other reliability investments that could yield greater benefits for the same amount of investment, including the basics such as tree trimming, moving cross-country poles to roadsides, animal protections, looping radial lines, and even undergrounding lines.

In general, having more diversity in type, size, scale, and vintage of resources is generally considered to bolster grid reliability and the robustness of resource portfolios (i.e., avoiding the problem of all the eggs in one basket). Distributed solar has increased these types of diversity in Vermont and the New England region over the last decade, but if solar continues to dominate as a resource type, benefits associated with that particular type of diversity will diminish. Distributed solar reduces Vermont's net loads and the need to purchase energy to serve load, when the solar fleet is producing. However, in the state and

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[168] https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj68rK0vMTtAhVYVs0KHTd7CxQQFjACegQIBBAC&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2018%2F02%2Fa2_implementation_of_revised_ieee_standard_1547_presentation.pdf&usg=AOvVaw1XF4tUehcQv9wj9zRgdIRg

[169] https://www.energy-storage.news/blogs/the-long-awaited-ieee-standard-that-paves-the-way-for-more-energy-storage-o

the region as a whole, each additional MW is shifting out the peak further into the evening, meaning incremental new solar will deliver energy at times it is not needed, necessitating utilities to resell excess supply at times when regional market prices are low (because everyone is doing the same thing). This issue is heightened in Vermont where utilities have invested through utility-owned generation or long-term contracts in non-solar renewable generation in order to fulfill statutory requirements.

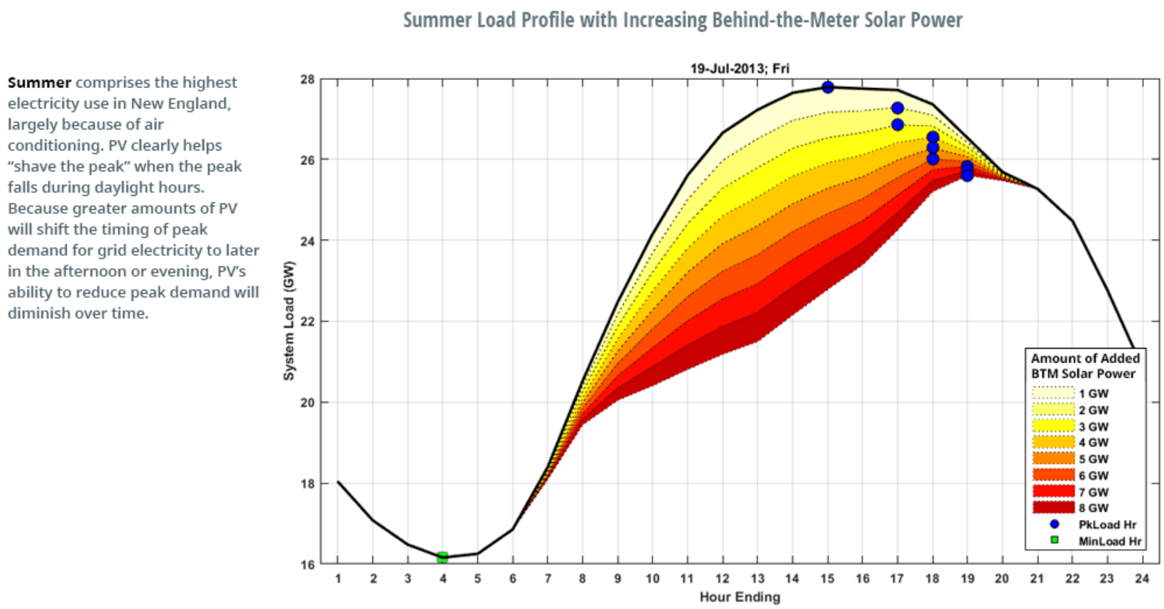
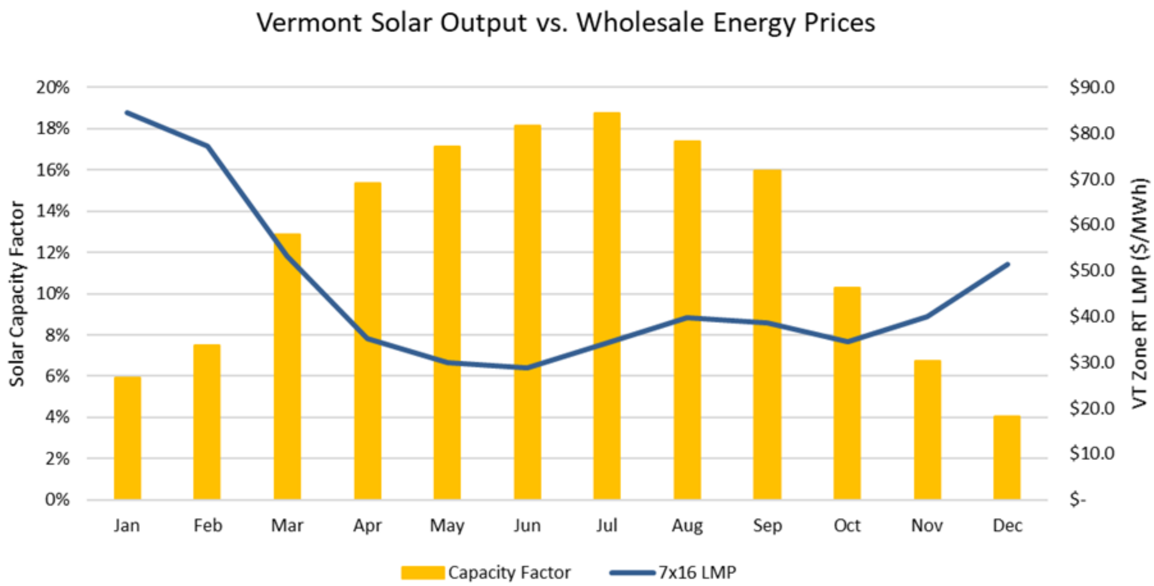


Figure 49: ISO-NE Summer Load Profile with additional behind-the-meter solar [170]

Figure 15 from ISO-NE shows the impact solar has had on net loads visible to the regional system operator, pushing them out into evening – a shape that will be exaggerated with the addition of electric vehicles that want to charge in the evening. Figure 16 below shows the average monthly wholesale energy prices over the past five years[171] and overlays the average monthly capacity factor of five representative standard offer solar projects.[172] As can be seen from the chart, the lowest energy prices tend to be in spring and fall, while the highest prices tend to be in winter. In other words, during the times when solar production is highest, wholesale prices tend to be low.

[170] https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact
[171] Monthly average prices were calculated based on hourly real-time Vermont zone clearing prices. This information can be downloaded here: https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/final-lmp-by-node (Last visited Oct. 25, 2019).
[172] Monthly average capacity factors were calculated based on the actual hourly generation from 2014 through 2018 for Ferrisburg Solar Farm, South Burlington Solar Farm, SunGen1 Solar, White River Junction Solar Farm, and Williamstown Solar Project. Each of these projects was commissioned before 2014 and has a contract through the Standard Offer program.



Based on actual capacity factors of 5 standard offer solar projects from 2014 through 2018.
7x16 LMP reflects the average Vermont Zone RT LMP from 7am-11pm each day of the year over the same 5-year period.

Figure 50: Vermont solar output compared to wholesale energy prices

In addition, utilities and system operators need to ensure sufficient resources are online to meet load regardless of the weather. Weather forecasting is becoming an increasingly powerful and accurate tool for assessing next-day and real-time demand in order to ensure sufficient resources are lined up to meet that demand, but day-to-day and minute-by-minute variability in storms and cloud cover for non-firm solar resources means grid operators may need to discount solar's availability (and thus contribution to meeting load and supplanting other resources). Figure 17 below shows the contribution (and resulting net load shapes) of solar on a cloudy vs. a sunny spring day, and the screen-capture of the regional system in real time just below that, Figure 18, shows the impact of winter storm Gail's snow cover on forecasted demand.

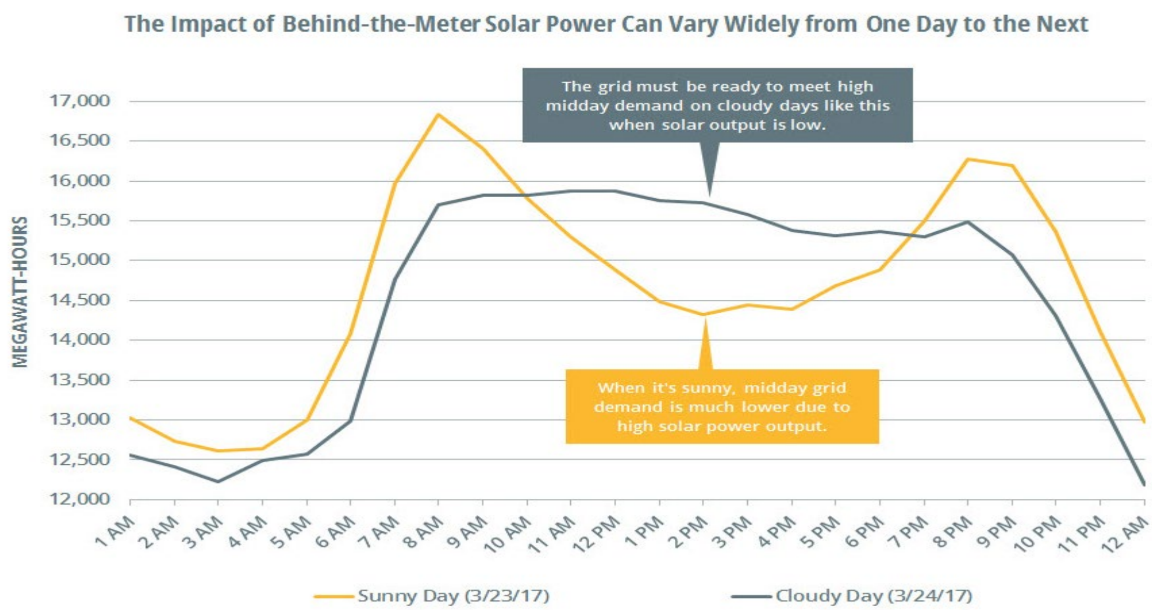


Figure 51: ISO-NE load shape with and without solar [173]

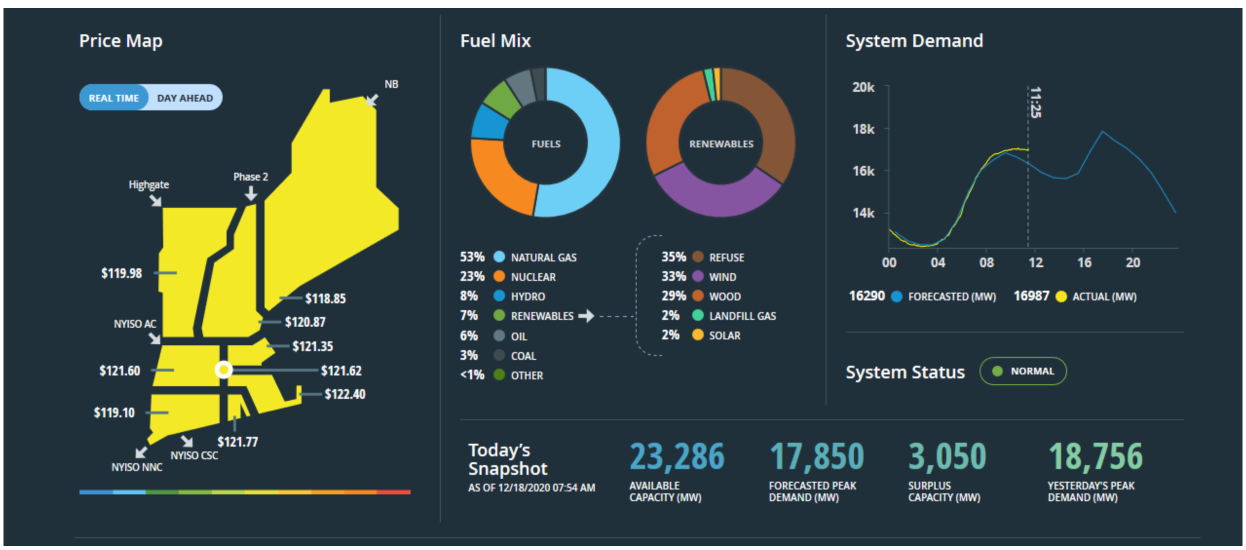


Figure 52: ISO-NE Energy Dashboard [174]

While net metering deployment has diversified resource supply in terms of sizes, it has been almost entirely composed of solar, most not coupled with storage, with uniform generation profiles that are

[173] See note 36.

[174] ISO-NE.com, screenshot taken at 11:30 a.m. on 12/18/20, the day after winter storm Gail. Relatively sunny conditions prevailed across the region, which ISO-NE likely took into account when they forecasted solar output decreasing midday-demand. The actual demand remained high, however, leading to increased prices and fossil fuel generation coming online. The Department interprets this chart to indicate many solar installations remained covered in snow, and it's unclear when they would start to again contribute to reducing loads.

becoming less well aligned with customer, circuit, utility, and regional load profiles, as penetration increases.

In other words, solar is becoming the biggest "egg" in Vermont's resource portfolio, at 30 percent of peak load (higher when considering average or low load days and months), and 50 percent penetration in some areas. Without changes to programmatic frameworks to better align production with loads (and vice versa), the value provided by net-metered solar will become increasingly disconnected from the compensation it is paid. Additive to the gulf between what ratepayers are paying for this resource and its value, are costs to integrate the solar fleet as it stresses the distribution system. Meanwhile, costs to serve load during non-solar hours and days remain. All these additional costs add to rate pressure, and keeping electric rates low is, in the Department's view, one of the most important measures Vermont can take to encourage electrification – and thus decarbonization – in the carbon-heavy heating and transportation sectors. A comprehensive approach to decarbonization, electrification, increasing renewables, grid modernization, and managing rates and costs is thus imperative to achieving Vermont's energy and climate goals in a least-cost manner.

Best Practices in Net Metering

Nationally, traditional net-metering – which typically involves crediting a customer for excess generation at the full retail rate the customer pays for energy services from the grid – is the most common program for customers who deploy small-scale generation. According to the North Carolina Clean Energy Technology Center, as of June 2020, 40 states, the District of Columbia, and four U.S. territories had mandatory rules regarding net-metering programs.[175]

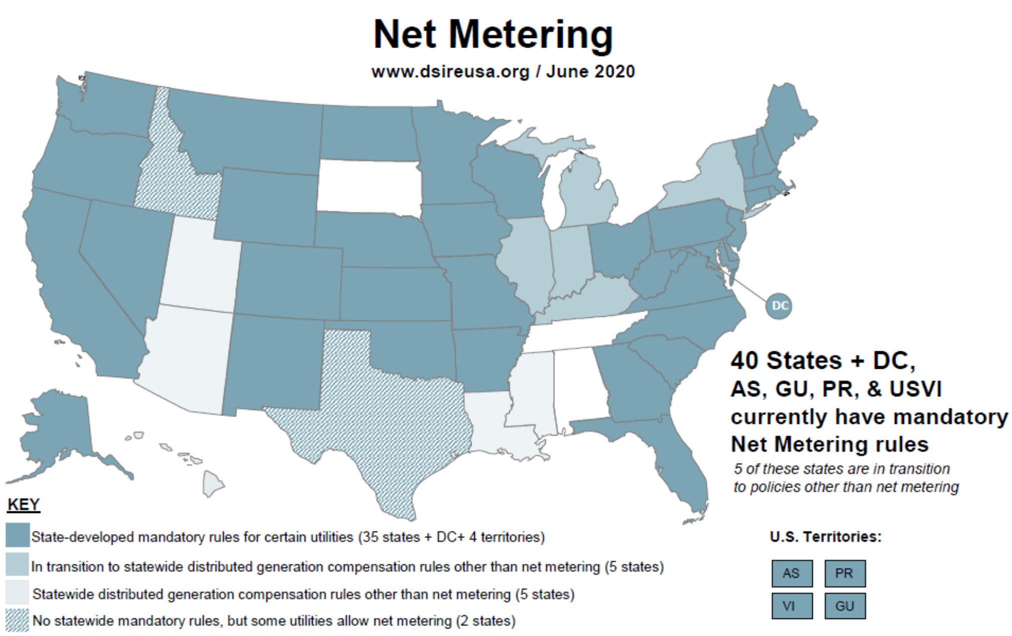


Figure 53: Summary of states with net metering rules

[175] North Carolina Clean Energy Technology Center, DSIRE. *Net Metering Policies (Updated June 2020)*. Retrieved from https://www.dsireusa.org/resources/detailed-summary-maps/

While traditional net-metering programs have helped stimulate the markets for small-scale, renewable distributed generation, as these programs have matured, a growing number of states (including Vermont) have started to explore and/or transition to alternative programs to support these resources. These transitions have been spurred by numerous reasons including:[176]

- Hitting previously established aggregate systems caps for traditional net-metering
- Proposals by utilities for alternative structures that better reflect the value these resources provide to the grid
- Concerns that net-metering customers are not fairly contributing to utility fixed costs and/or are being subsidized by non-participating customers
- Other legislative or regulatory requirements

Outside of Vermont, a growing number of states either have transitioned or are in the process of transitioning to alternative compensation structures for distributed generation. As illustrated in the figure, new net-metering and distributed generation programs focus on shifting several aspects of traditional net-metering rate designs in efforts to address more accurately reflecting the value of these resources to the grid and cost-shifts among customers, including: the rate at which excess generation is compensated; treatment of fixed charges and minimum bills for customers; and even creating separate customer classes for customers who own distributed generation resources.[177] In Q3 of 2020 alone, 43 states and the District of Columbia took 146 actions on distributed solar policy and rate design, with the top three actions involving distributed generation compensation rules (taken by nearly 30 states, 40% of actions), community solar (19 states, 24% of actions), and residential fixed charges or minimum bill increase (18 states, 14% of actions).[178]

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[176] Stanton, T. (2018). *Review of State Net Energy Metering and Successor Rate Designs.* Retrieved from https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/

[177] Stanton, T. (2018). *Review of State Net Energy Metering and Successor Rate Designs.* Retrieved from https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/

[178] North Carolina Clean Energy Technology Center, The 50 States of Solar: Q3 2020 Quarterly Report, October 2020. Retrieved from https://static1.squarespace.com/static/5ac5143f9d5abb8923a86849/t/5f8f47d4b9163c3af23b88cc/1603225561979/Q3-20_SolarExecSummary_Final.pdf

Policy Types	Vertically Integrated States	Restructured States
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

1 See Figure 2, p. 12.

2 In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

3 See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

Figure 54: DER Policy Types Adopted by States (including Vermont)[179]

With regard to compensation rules, programs differ a variety of issues, such as whether compensation is based on estimates of avoided costs or the value of solar, the extent to which they include time-based or location-specific components,[180] and when (or if) customers can export to the grid. Table 5 provides a comparison of 10 states that are considering or have adopted compensation mechanisms other than the full retail rate for net metering. Several states, including Arizona and Indiana, have moved toward tying compensation for excess generation to the utilities' avoided cost or wholesale prices for electricity. Others, such as Connecticut and Georgia, are considering compensation structures that combine kwh-netting with credits for excess generation at avoided cost.

[179]Source: Stanton (2018) *Review of State Net Energy Metering and Successor Rate Designs, Table 1, pg 2*

[180] Satchwell, A., Cappers, P. & Barbose, G. (2018). *Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources.* Retrieved from https://emp.lbl.gov/publications/current-developments-retail-rate.

State	Adopted or Proposed Alt. Compensation Mechanism/Value for Excess Generation	Description
Arizona*	Avoided cost (AC) or Resource Comparison Proxy (RCP)	Treats rooftop solar as a separate customer class; Compensation determined in rate cases; **AC**: Based on 5 year running average of utility scale solar, T&D, capacity, & line loss costs **RCP**: based on utility projects and PPAs with in-service dates within the five years up to and including the test year of the rate case;
Connecticut	kWh netting month-month; Credited at avoided cost annually	Credit the kWh amount of excess generation on the following months bill at 1:1 ratio; At the end of an annualization period, utility credits customers at avoided cost of wholesale power based on average hourly Connecticut ISO-New England Real-Time Locational Marginal Price (RT-LMP); For solar resources specifically, hours of 10 a.m. to 4 p.m. during the annual period are used to calculate the average avoided cost. For systems with nameplate capacity >10kW, will pay system benefits charge based on amount of energy provided by the utility without any netting of kWh; After 2039, PURA will est. rate for cents/kWh for DU to purchase excess gen
Georgia	kWh netting month-month + avoided cost	Excess kWh generation produced by systems less than or equal to 250kW will be summed monthly and applied to reduce that month's energy consumption; Any kWh that exceed the monthly usage will be credited at the "Solar Avoided Cost Rate" set by the Commission. In Georgia Power territory, facilities between 250kW and 80MW can sell electricity as a "Qualifying Facility" at the hourly avoided cost rate.
Indiana	1.25x average wholesale prices for electricity	Will phase out retail rate NM by either 1) Jul 2022 or 2) when utilities hit 1.5% peak summer load cap. New compensation will be set via rate cases annually and will vary by utility; Excess generation will be credited at 1.25 times the average marginal price of electricity paid by the utility in the previous year; Customers will receive bill credits each month for the value of excess generation
Kentucky	Bill credits for excess generation at a value set by PSC in rate cases	In comments to Commission, received numerous proposals for best way to consider utility-specific costs of NM including avoided cost, value of energy supplied to the grid, market-based rates, and quantification of externalities (ex. environmental, societal benefits); Commission will hire consultant to help review/analyze new NM tariffs and rate designs; In new NM program utilities may recover all costs necessary to serve NM customers
Louisiana*	Avoided cost	Based on 12-month average locational marginal price for each utility Updated annually
Mississippi*	Avoided cost + "Non-quantifiable expected benefits adder"	Customers have bidirectional meters, one channel measures net of total system generation and total customer electricity usage in real time; Self-supplied generation is credited at the retail rate and excess generation is credited at utility avoided cost plus adder of $0.025/kWh to account for benefits of DG; Credits apply to monthly bill; Adder value will be assessed within three years to calculate actual benefits of DG

Michigan	Inflow-Outflow; Credit at retail rate or power supply component of retail rate	Credit customer next bill at retail rate for systems <20kW; Credited at power supply component of retail rate for larger systems
New York	Value of Distributed Energy Resources (VDER) and volumetric crediting	VDER calculation ("value stack") includes five major pricing components: location-based marginal prices, install capacity, environmental benefits, demand-reduction value, and a location-based system relief value; Currently available to commercial and industrial customers, mass market & small commercial can opt into VDER but default to volumetric crediting. Solar customers will pay a customer benefit charge ("CBC") in efforts to begin to address the cost shift between participating and non-participating net-metering customers. The CBC is estimated to fall between $0.69 and $1.09/kW DC depending on the utility and customer service class.
South Carolina	Time-varying rates (Time-of-Use, Critical-Peak Pricing) and Avoided Cost	The program will net energy exports and imports within each TOU pricing tier. CPP will apply to any customer imports during the critical peak period, but any exports will be netted against peak imports (not CPP imports). At the end of each month, customers will receive bill credits for any net exports valued at avoided cost, with the credit reducing the bill after application of the minimum bill payment.
*Rate has been adopted by the state		

Table 13: Comparison of Alternative Compensation Mechanisms for Excess Generation from Net-Metered / Distributed Generation Systems

Alternatively, as part of the Reforming the Energy Vision ("REV") proceeding, New York has adopted an alternative to traditional net-metering which aims to compensate customers based on the value of distributed energy resources ("VDER"). The new program has five major pricing components: location-based marginal prices, install capacity, environmental benefits, demand-reduction value, and a location-based system relief value.[181] Together, these five components make up the "value stack." Location-based marginal pricing is tied to the day-ahead wholesale market hourly price for the energy commodity whereas install capacity values stems from the wholesale market average monthly price for capacity provided. For the environmental benefit, the cost is fixed for a 25-year terms based either on the social cost of carbon or REC Tier 1 value, whichever is greater. Note, if a customer keeps the RECs associated with the system, the environmental benefit is not included in the value stack calculation. Finally, the demand-reduction and location-based system relief values are calculated on a dollar per kW-year value (updated every three and 10 years, respectively) for each utility. Value stack compensation is provided to customers as a monetary value, crediting the customer for net hourly exports to the grid based on each of the values realized. New York intends to conduct a phased rollout of the new compensation mechanism, with value stack compensation available for most commercial and industrial customers while placing mass market[182] customers have the option to opt into value stack compensation.

In addition to the rate at which utilities compensate customers for the excess generation produced by their systems, states have begun to consider how programs might influence when net-metering or distributed generation systems can export that excess generation to the grid. For example, after helping

[181] Satchwell, Cappers, & Barbose (2018).
[182] Mass market is defined as a customer who has PV at the site of the offtaker, either residential or small commercial solar electric customers with non-demand billing.

install 487 MW of PV capacity between 2005-2015,[183] Hawaii's original net-metering program ended in late 2015 and the state has been working to transition to a longer-term solution which seek to better manage when customers are able to export to the grid and compensate them accordingly. Currently this solution involves two programs, called Smart Export and Customer Grid Supply Plus (CGS+), which are now available to customers.

On the CGS+ tariff, a customer can export energy from rooftop solar or other renewables to the grid in exchange for a monthly bill credit for the excess generation. Credits expire at the end of each year and a customer must install equipment to allow the utility to manage output. Thus, under certain situations, a utility may choose to curtail output from CGS+ customers. In such a scenario, all CGS+ would be curtailed in a single block, and customers would not be able to generate until the end of the event. Rates for excess generation differ by utility and currently range between $0.1055/kWh to $0.208/kWh. The program will remain open until capacity limits are hit (these differ by location: Oahu – 35 MW, Maui County – 7 MW, and Hawaii Island – 12 MW).[184]

The second option, Smart Export, allows customers to install distributed generation plus battery storage. Under this tariff, customers charge the battery from the generation system during daylight hours (9 a.m.-4 p.m.). Customers do receive a bill credit for excess generation exported to the grid outside the charging window, with the credits ranging from $0.11/kWh to $0.2079/kWh depending on the utility. Similar to CGS+, the Smart Export program will remain open until installed capacity limits are reached (Oahu – 25 MW, Hawaii Island – 10 MW, Maui County – 5 MW) and export credits expire on an annual basis.[185]

Underlying many new program proposals are considerations of how innovative rate designs might be employed incentivize customers to correctly size their net metered or distributed generation systems and augment they value they provide to the grid. In New York, the Commission convened a working group (the VDER Rate Design Working Group) to specifically investigate appropriate rate designs for future net-metering programs. Work from this group initially culminated in a NY State Department of Public Service staff white paper in December 2019 on *Rate Design for Mass Market Net Metering Successor Tariffs* and is ongoing today. In Kentucky, the Public Utility Commission aims to hire a consultant to help review and analyze new net metering tariffs and rate designs.

Similarly, in September 2020 a coalition of industry stakeholders announced a new settlement agreement for an alternative to net-metering in South Carolina seeks to combine innovative rate designs (time-of-use, or "TOU," and critical peak pricing, or "CPP"), demand response through load control technologies, distributed generation installation, and energy efficiency. The coalition included Duke Energy (who operates two of South Carolina's major utilities, Duke Energy Carolinas and Duke Energy

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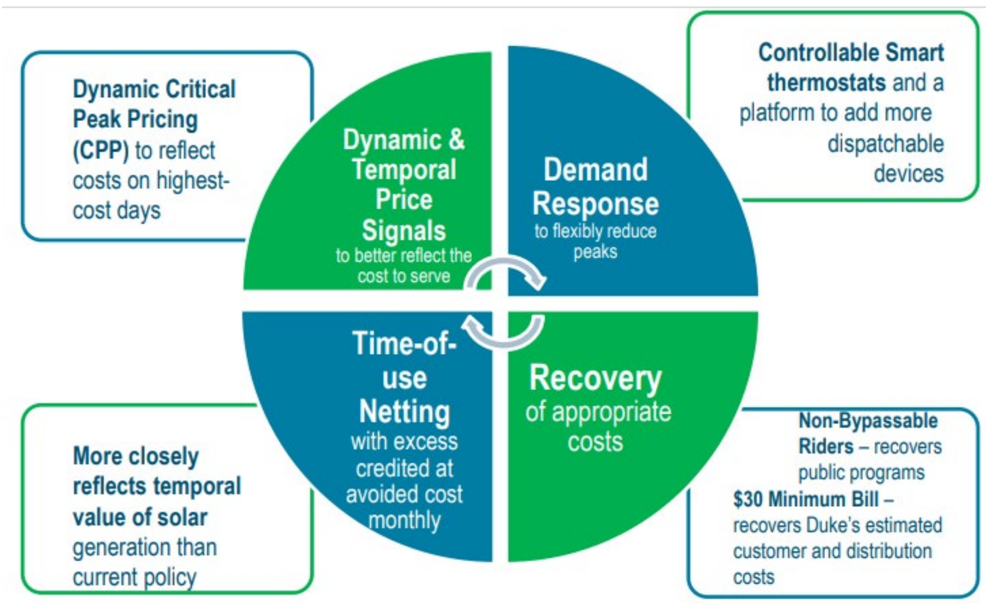
[183] Hawaiian Electric, *Customer Renewable Programs: Net Energy Metering.* Retrieved from https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/net-energy-metering.

[184] Hawaiian Electric, *Customer Renewable Programs: Customer Grid-Supply Plus.* Retrieved from: https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/customer-grid-supply-plus

[185] Hawaiian Electric, *Customer Renewable Programs: Customer Grid-Supply Plus.* Retrieved from: https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar/smart-export

Progress) and solar developers.[186] The proposed plan aims to send more accurate price signals through a number of customer rate structures. The TOU rate will have three tiers: on-peak (6 p.m.-9 p.m. annually, plus 6 a.m.-9 a.m. December-February), off-peak, and super off-peak (12 a.m.-6 a.m. March-November). CPP days and hours will be set daily and posted to the utility's website. The program will net energy exports and imports within each TOU pricing tier. CPP will apply to any customer imports during the critical peak period, but any exports will be netted against peak imports (not CPP imports). At the end of each month, customers will receive bill credits for any net exports valued at avoided cost, with the credit reducing the bill after application of the minimum bill payment. Demand response will initially be incentivized through a smart thermostat program (which comes with additional incentives), and Duke Energy will continue to explore additional bring-your-own controllable device options. Based on a cost-of-service rate design, the program is estimated to significantly reduce the cost-shift associated with net-metering by 92-96 percent.[187] The new settlement is currently under review by the South Carolina Public Utility Commission and, if approved, would apply to new net-metering customers starting January 1, 2022.



Overview of Duke / South Carolina Proposed Net Metering Successor[188]

As markets for solar and other distributed generation technologies have matured, many states have made concerted efforts to move away from traditional net-metering programs and identify alternative compensation mechanisms. These new programs aim to reflect the value these resources currently provide to the grid more accurately and reduce cost shifts to non-participating customers. As many of these programs are in the initial stages of development and/or implementation, the Department will

[186] Docket. No. 2019-169-E (Sept. 21, 2020). *Duke Energy Progress, LLC's Establishment of Net Energy Metering Tariff in Compliance with H. 3659 - Letter Regarding Stakeholder Agreement and Press Release.* Retrieved from https://dms.psc.sc.gov/Web/Dockets/Detail/117126
[187] Smart Electric Power Alliance Webinar (October 1, 2020) *Ask the Experts: Renovating Rooftop Rate Design.*
[188] Ibid.

continue to monitor early results of the programs to better understand lessons learned that might inform future net-metering programs in Vermont.

Conclusion

Net metering has made important contributions to Vermont's energy supply mix; however, after more than 20 years and hundreds of MW of installed projects, it is past time for an overhaul of the net metering compensation structure. The primary resource developed under net metering is solar generation, which is also being developed through competitive solicitations at substantially lower costs. If Vermont is serious about reducing climate change, it is imperative that the state be willing to take an objective view of what programs are helping to achieve this purpose.

Appendix F – Energy Data

Forecasted Annual Energy Use (GWh)

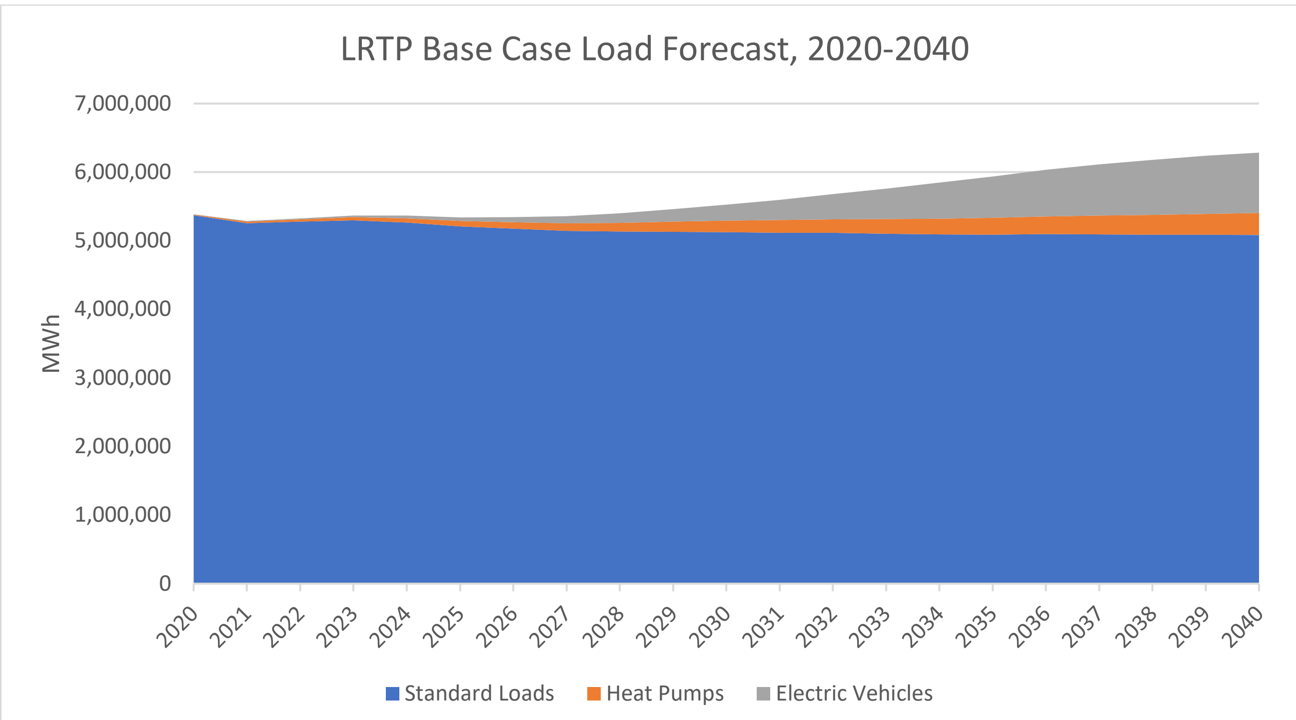
Energy use is estimated to be relatively flat over the next ten years. Both ISO-NE and Vermont load forecasts anticipate additional behind-the-meter generation that is more than offset by forecasted electrification in the heating and transportation sectors.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Vermont	5,385	5,288	5,326	5,369	5,365	5,341	5,345	5,357	5,399	5,460
New England	124,184	123,268	123,688	123,864	124,539	124,678	125,350	126,303	127,834	128,781

Source: Vermont data from: 2020 Long-Term Electric Energy and Demand Forecast Report, Vermont Electric Power Company, prepared by Itron (in press, but will be available at: https://www.vermontspc.com/)

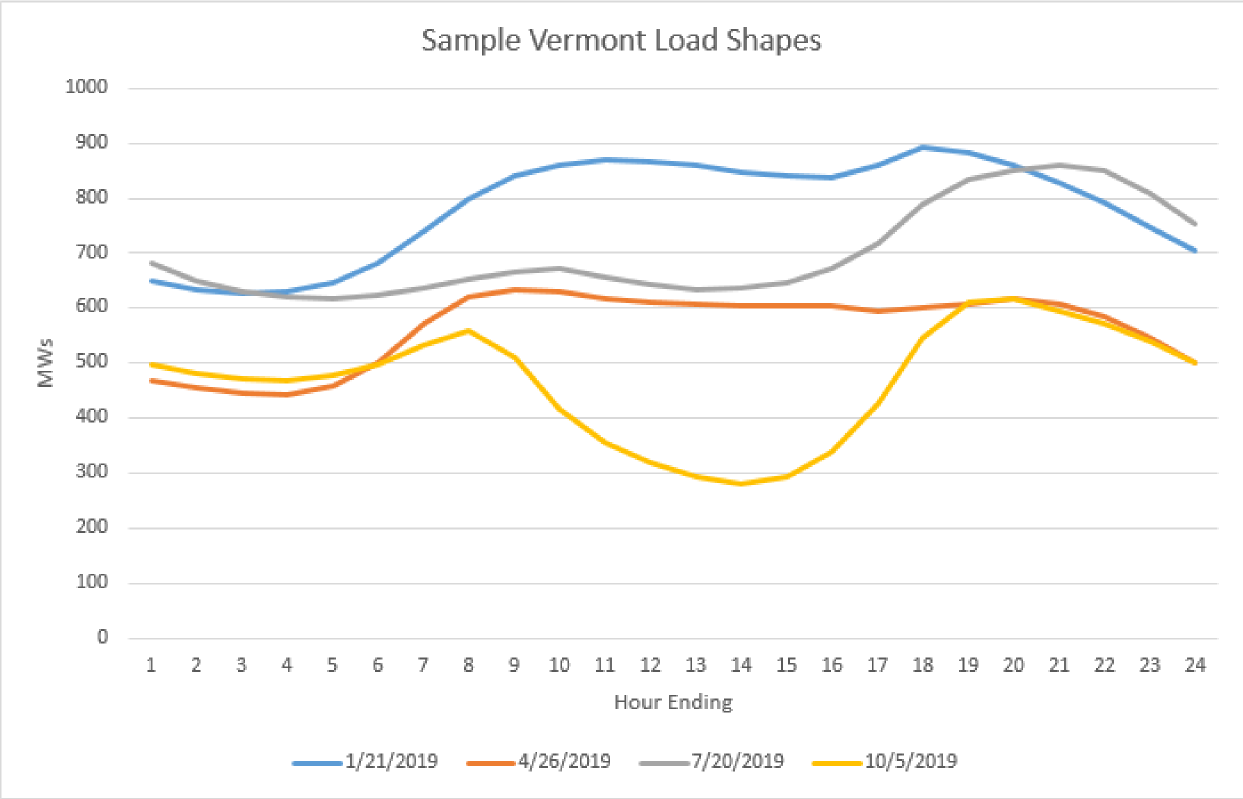
New England data from: 2020 ISO-NE CELT Report; Table 1.5.2 Net Annual Load Forecast (available at https://www.iso-ne.com/system-planning/system-plans-studies/celt)

VELCO Long Range Transmission Plan Load Forecast



Source: 2020 Long-Term Electric Energy and Demand Forecast Report, Vermont Electric Power Company, prepared by Itron (in press, but will be available at: https://www.vermontspc.com/)

Vermont Seasonal Load Profiles



Historical Peak Loads

ISO-NE System					Vermont		
Year	Peak Date	Hour Ending	System Peak Load (MW)	Vermont Coincident Peak (MW)	Peak Date	Hour Ending	System Peak Load (MW)
2001	8/09/2001	15:00	24,723				
2002	8/14/2002	15:00	25,103				
2003	8/22/2003	15:00	24,311				
2004	8/30/2004	16:00	23,719				
2005	7/27/2005	15:00	26,618				
2006	8/02/2006	15:00	28,038				
2007	8/03/2007	15:00	25,773		8/3/2007	14	1001
2008	6/10/2008	15:00	25,691		1/3/2008	19	983
2009	8/18/2009	15:00	24,708		12/17/2009	18	969
2010	7/06/2010	15:00	26,701	979	7/8/2010	14	1,007
2011	7/22/2011	15:00	27,312	931	7/22/2011	12	984
2012	7/17/2012	17:00	25,543	920	6/21/2012	16	945
2013	7/19/2013	17:00	26,911	946	7/18/2013	14	988
2014	7/02/2014	15:00	24,068	900	1/2/2014	18	972
2015	7/29/2015	17:00	24,052	868	1/8/2015	18	924
2016	8/12/2016	15:00	25,111	849	1/4/2016	18	931
2017	6/13/2017	17:00	23,508	726	12/29/2017	18	942
2018	8/29/2018	17:00	25,559	837	7/2/2018	20	935
2019	7/30/2019	18:00	23,929	796	1/21/2019	18	892
2020*	*7/27/2020*	*18:00*	*24,695*	*830*	*7/27/2020*	*20*	*890*

**2020 data is preliminary.*

Source: FCM Annual System Peak Day, Hour, and Load https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/ann-sys-peak-day-hr-load

Vermont data from: VELCO

Net Forecasted Summer Peak (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Vermont	942	937	957	974	982	986	992	1,000	1,011	1,026
New England	25,125	24,981	24,861	24,783	24,703	24,657	24,640	24,656	24,694	24,755

Source: Vermont data from: 2020 Long-Term Electric Energy and Demand Forecast Report, Vermont Electric Power Company, prepared by Itron (in press, but will be available at: https://www.vermontspc.com/)

New England data from: 2020 ISO-NE CELT Report (available at https://www.iso-ne.com/system-planning/system-plans-studies/celt)

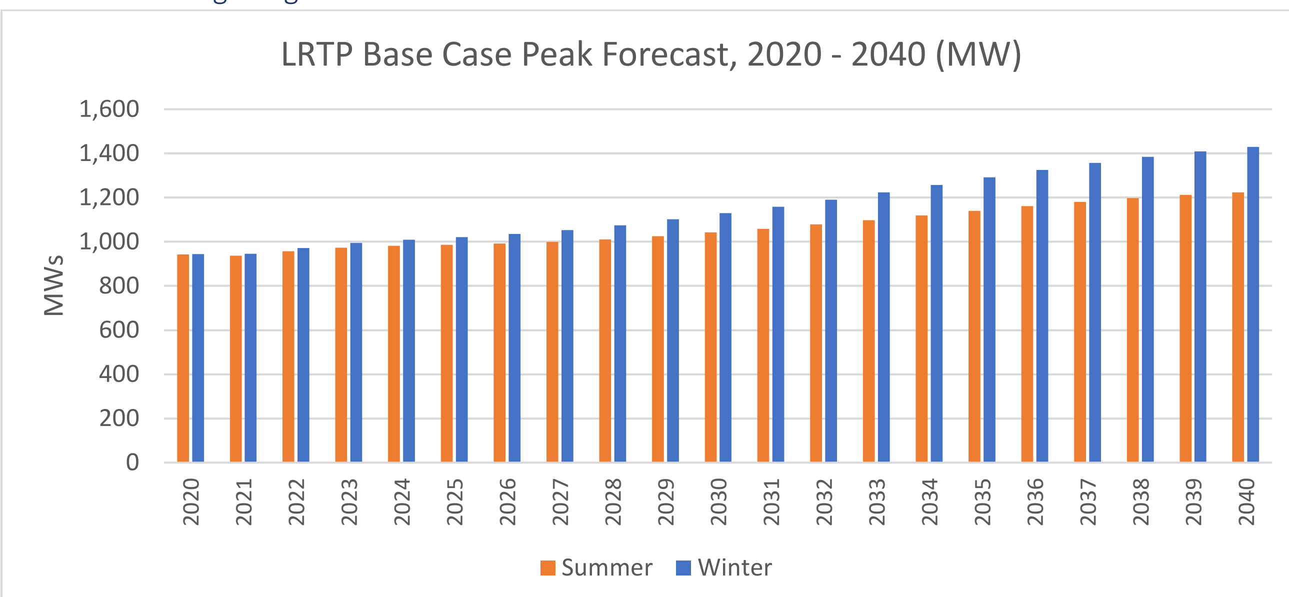
Net Forecasted Winter Peak (MW)

	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030
Vermont	945	972	995	1,009	1,021	1,036	1,053	1,075	1,101	1,130
New England	20,166	20,075	19,993	19,942	19,922	19,943	20,000	20,093	20,200	20,334

Source: Vermont data from: 2020 Long-Term Electric Energy and Demand Forecast Report, Vermont Electric Power Company, prepared by Itron (in press, but will be available at: https://www.vermontspc.com/)

New England data from: 2020 ISO-NE CELT Report (available at https://www.iso-ne.com/system-planning/system-plans-studies/celt)

VELCO 2021 Long Range Transmission Plan Peak Forecast

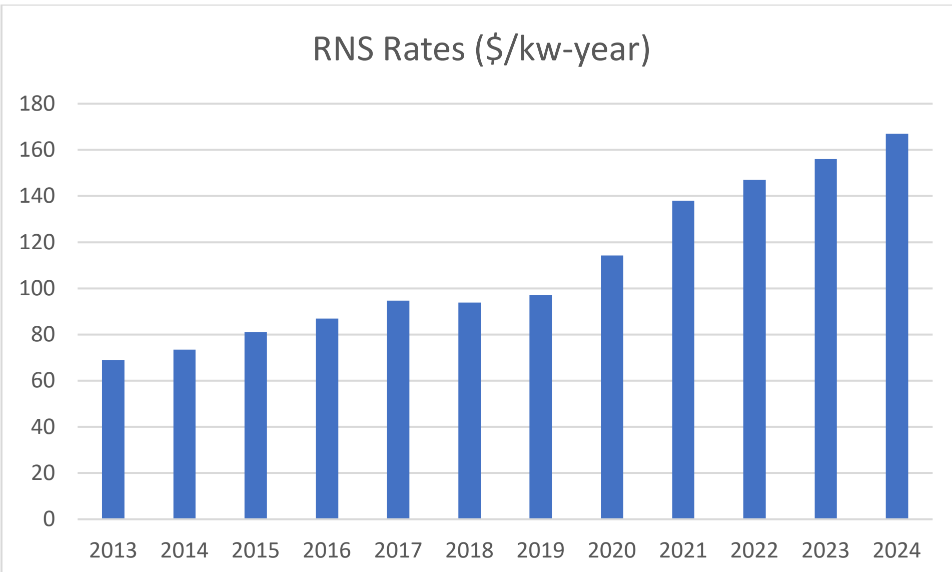


Source: 2020 Long-Term Electric Energy and Demand Forecast Report, Vermont Electric Power Company, prepared by Itron (in press, but will be available at: https://www.vermontspc.com/)

Regional Network Service Forecasted Rates

Year	2021	2022	2023	2024
RNS Rate ($/kW-year)	$138	$147	$156	$167

Source: August 18-19, 2020 NEPOOL Reliability Committee/ Transmission Committee Summer Meeting

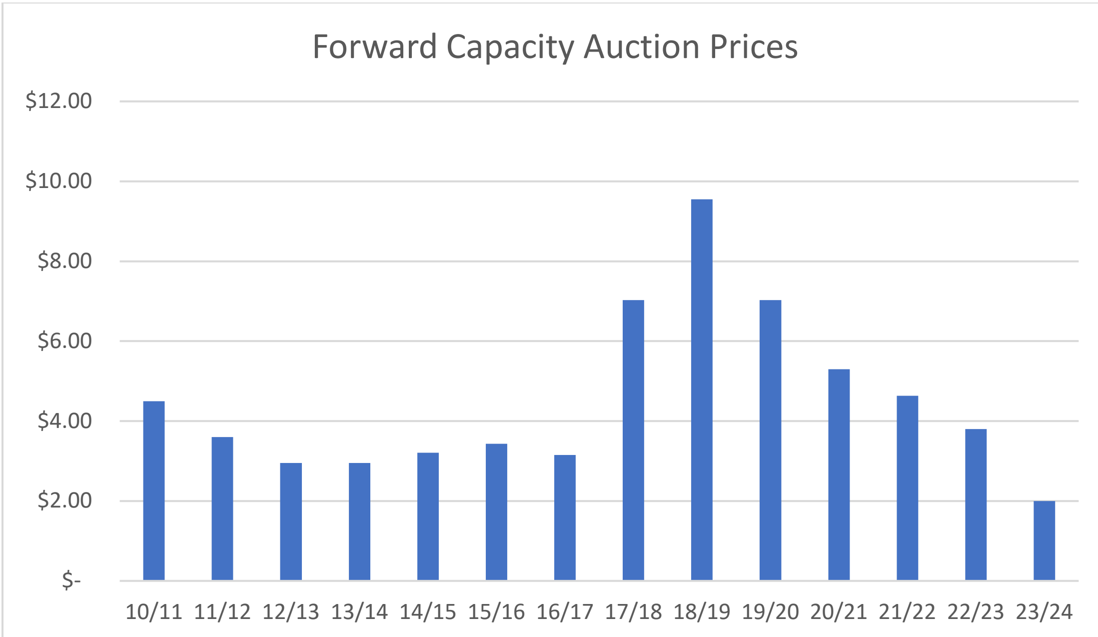


ISO-NE Forward Capacity Auction Results

AUCTION COMMITMENT PERIOD	TOTAL CAPACITY ACQUIRED (MW)	NEW DEMAND RESOURCES (MW)[1]	NEW GENERATION (MW)[2]	CLEARING PRICE ($/KW-MONTH)
FCA #1 in 2008 for CCP 2010/2011	34,077	1,188	626	$4.50 (FLOOR PRICE)
FCA #2 in 2008 for CCP 2011/2012	37,283	448	1,157	$3.60 (FLOOR PRICE)
FCA #3 in 2009 for CCP 2012/2013	36,996	309	1,670	$2.95 (FLOOR PRICE)
FCA #4 in 2010 for CCP 2013/2014	37,501	515	144	$2.95 (FLOOR PRICE)
FCA #5 in 2011 for CCP 2014/2015	36,918	263	42	$3.21 (FLOOR PRICE)
FCA #6 in 2012 for CCP 2015/2016	36,309	313	79	$3.43 (FLOOR PRICE)
FCA #7 in 2013 for CCP 2016/2017	36,220	245	800	$3.15 (FLOOR PRICE)
FCA #8 in 2014 for CCP 2017/2018	33,712	394	30	$15.00/new & $7.025/existing*
FCA #9 in 2015 for CCP 2018/2019	34,695	367	1,060	$9.55
FCA #10 in 2016 for CCP 2019/2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020/2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021/2022	34,828	514	174	$4.63
FCA #13 in 2019 for CCP 2022/2023	34,839	654	8,373	$3.80
FCA #14 in 2020 for CCP 2023/2024	33,956	323	335	$2.00

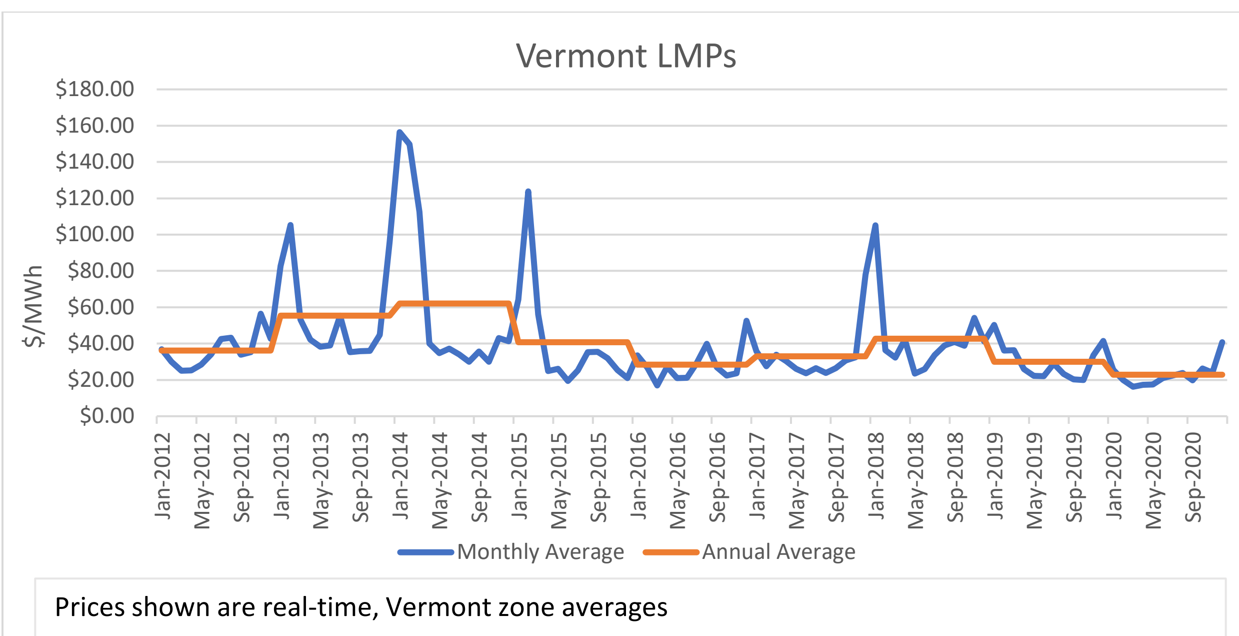
*The blended price that was paid to settle load was $7.60/kW-Month.

Source: https://www.iso-ne.com/about/key-stats/markets#fcaresults



Wholesale Energy Prices

The chart below illustrates the annual and monthly wholesale energy prices from 2012 through 2020 for the Vermont zone. As can be seen in the chart, in the past 8 years, price spikes have occurred almost exclusively during winter months. During extreme cold weather events, the natural gas supply for electric generators becomes constrained and prices increase as more expensive resources are called on. In 2020, as a result of the mild winter and lower loads due to COVID-19, New England experienced the lowest annual average prices since the start of the wholesale markets.



In-State Generating Capacity