VERMONT
DEPARTMENT OF PUBLIC SERVICE

Dear Fellow Vermonters:

> **"I believe there is no greater challenge and opportunity for Vermont and our world than the challenge to change the way we use and produce energy."**
>
> — Governor Peter Shumlin
> December, 2011

Five years ago, under the leadership of Governor Peter Shumlin, we embarked on a new energy future for Vermont. The goal of achieving 90% of Vermont's total energy needs from renewable sources by 2050 was visionary, but just that — a goal. Since then, Vermont has shown not only the worthiness of that goal for our energy security and environmental benefit but also its achievability and affordability. Not only can Vermont be a leader in global climate change efforts, but we can do so while increasing our energy security, improving our economy, protecting ratepayers, and reducing our total energy costs.

In the last five years, Vermonters have embraced this effort with enthusiasm, expanding our in-state renewables by over 250 megawatts of electric capacity. We've improved on our already nationally recognized work in electric efficiency, and expanded efforts to advance thermal efficiency. We added over 100 MW of new wind generation, and repowered hydropower at several existing Vermont dams in an environmentally sound manner. By far, the greatest growth has been in solar — with net metering at homes, farms, businesses, and throughout communities accounting for nearly 90 MW alone. All this while keeping the cost of electricity at or below the rate of inflation and securing electric bill reductions in three of the last four years for a vast majority of Vermonters.

Our list of accomplishments includes updated building codes for energy efficiency and renewable energy preparedness; expanded financing opportunities to help improve the efficiency of our housing, and to roll out advanced new technologies such as heat pumps; plus the addition of almost 100 electric vehicle charging stations and — perhaps the best demonstration that Vermonters are fully committed to this effort — the fast-paced adoption of electric vehicles, with more than one out of every 100 new vehicles purchased in Vermont over the last two years being a plug-in or fully electric vehicle. In addition, our land-use policies have been strengthened to encourage smart growth and its associated energy savings; in Montpelier, we added Vermont's first community district energy system fueled by sustainable forest resources; and finally, Vermont created the nation's first truly integrated Renewable Energy Standard through Act 56, which integrates increasing renewable energy with reducing total energy use and costs. In the next pages, you will see our joint vision to advance our goals in a specific way that shows how we can do so responsibly and affordably.

None of this would have been possible without partnerships and countless citizens stepping forward to do their part. Vermont now has over 16,000 jobs in the clean energy sector, which accounts for almost 5% of our workforce. Lenders, including Vermont banks, credit unions, and the Vermont Economic Development Authority, have made millions of dollars in loans to Vermonters who have sought financing to advance these goals. Homeowners and other electric customers have rocketed through two net metering caps and continue to demonstrate an appetite for more.

Formulation of this plan would also not have been possible without the dedication of Vermonters from all over the state. Hundreds of comments helped make this plan better. Other participating state agencies, stakeholders, and the Department's dedicated staff deserve recognition for completing this tremendous effort. In the end, without active citizen participation, the plan is just a plan. While we can and should all be proud of Vermont's progress to date, I so much value the commitment Vermonters have shown to implement the vision embodied in this plan. If we continue on the path we have been on for the last five years, Vermont will be well on our way to meeting our goals, and we will leave our state more beautiful and much stronger for the next generation.

Thank you all,

Christopher Recchia, Commissioner

Executive Summary

Vermont stands at a moment of great promise for a clean energy future. Over the four years since the publication of the last Comprehensive Energy Plan, Vermonters have built a foundation of infrastructure, policies, and programs on which to construct an increasingly renewable energy economy. We must build upon this foundation to accelerate progress toward the goals included in this plan. Vermont's energy transformation will take many years to fully implement; along the way it will enhance the vitality of our state's economy, improve our health, and improve the quality of our local and global environment. This 2016 Comprehensive Energy Plan provides a framework to advance those goals, along with specific plans and recommendations for action by the public and private sectors.

This Comprehensive Energy Plan (CEP) is built around these themes and cross-cutting insights:

- Vermont develops and pursues energy policy, not for its own sake but as a tool to advance economic, environmental, and health objectives.
- Our energy future is largely a product of infrastructure, both public and private.
- Vermont is well-positioned to thrive in the transition to distributed energy resources, linked and coordinated through enhanced communications.
- Energy system innovation provides an opportunity for Vermont to foster entrepreneurship, while also keeping more of our energy spending in-state.

Guiding economic, environmental, and health goals

Vermont's energy policy, as codified in 30 V.S.A. § 202a(1), establishes these state goals:

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.

Energy adequacy, reliability, security, and affordability are essential for a vibrant, resilient, and robust economy. Energy efficiency is a driver of productivity. Environmentally sound energy policy rises in prominence in the context of our urgent need to mitigate the global climate change that is resulting from greenhouse gas emissions while also advancing local environmental sustainability. Vermonters' health is a necessary consideration, shaped by infrastructure and by both economic and environmental forces.

Chapter 3 of the CEP identifies and describes the policy objectives of this plan, which are summarized in the box on the next page. It also explicitly addresses the fact that those goals may at times be in conflict, and makes explicit this CEP's attempt to identify and promote those recommendations that advance all objectives over those options that produce conflict.

This CEP advances these guiding goals, both through the detailed recommendations found throughout the plan and by building on the state's goal, established in the 2011 CEP, of meeting by mid-century 90% of Vermont's energy needs from renewable sources while virtually eliminating reliance on oil. **Expanding upon the statutory goal of 25% renewable by 2025 (10 V.S.A. § 580(a)), this CEP establishes the following set of goals:**

- **Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 2050.**
- **Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050.**
- **Three end-use sector goals for 2025: 10% renewable transportation, 30% renewable buildings, and 67% renewable electric power.**

Taken together, meeting these goals will increase affordability and economic security for both residents and businesses by increasing energy efficiency and relying on more stably priced resources than alternative paths offer. Meeting them will also strengthen Vermont's economy and enhance our state's capital infrastructure by shifting energy expenditures from fuels produced out of state to in-state infrastructure and fuel supplies. Increasing the use of fuels produced on Vermont's farms and forests can enhance the security of those critical sectors of the state's economy while also improving their environmental stewardship.

Since the last CEP was published in 2011, Vermont has added more than 100 MW each of in-state wind and solar photovoltaic (PV) electric generation. Implementation of Act 56 and the Renewable Energy Standard (RES) will further drive Vermont toward meeting our interim and overall goals. We are doing all this while keeping electric

Guiding Goals When Developing and Evaluating Energy Policy

A Vibrant and Equitable Economy

- **Ensure an affordable and stable cost of living** through improving the energy fitness of Vermont homes, strategic electrification, focusing development in compact villages and urban centers, and substituting fossil fuels with renewable alternatives that have lower long-term costs.
- **Ensure an affordable and stable cost of doing business** through improvements in commercial and industrial building and process energy efficiency, strategic electrification, and the substitution of renewable alternatives for fossil fuels.
- **Increase entrepreneurship opportunities** by supporting market demand for renewable energy and energy efficiency services, as well as encouraging research and commercialization of new energy services and technologies.
- **Improve labor market conditions** by creating well-paying jobs in industries that supply renewable energy commodities and energy efficiency services.
- **Ensure an equitable distribution of benefits and burdens** by assisting those least able to pay the increasing costs of energy and the upfront costs for investments in efficiency and fuel switching.
- **Maintain revenue to support government functions** by replacing the reduction in income from the sale of taxable fuels, such as motor fuels, with appropriate new revenue sources.

Healthy Ecosystems and a Sustainable Environment

- **Reduce greenhouse gas emissions,** consistent with the state's emission-reduction goals, by reducing fossil fuel use and efficiently using renewable energy sources.
- **Reduce local air pollutants**, including particulates and toxins, by using efficient and clean combustion technologies, along with shifting away from fossil fuels.
- **Bring a global and life-cycle perspective** to the analysis of costs and benefits.
- **Retain healthy, functional forest and agricultural systems** through responsible use of forest and agricultural resources for energy and non-energy-related applications.
- **Maintain water quality throughout Vermont's ecosystems** through responsible land and water use.
- **Optimize land use choices** to minimize local and global environmental impact, including balancing land use among competing needs in the state for energy, non-energy development, housing, transportation, working lands for agriculture and forestry, and other purposes.

Healthy Vermonters

- **Encourage active lifestyles** and reduced energy use through compact development and by providing safe opportunities for walking, biking, and using public transit.
- **Improve outdoor air quality** by reducing emissions from transportation, home and business heating and energy usage, and energy production.
- **Improve the health of indoor environments** and reduce energy bills through improved building weatherization and the use of advanced heating and ventilation technologies.
- **Reduce negative health impacts** expected to occur as a result of climate change.
- **Assess health impacts of our energy system** in order to avoid or mitigate potential negative impacts, especially for the most vulnerable population groups such as the elderly, low-income households, and those with chronic or pre-existing medical conditions.

rates stable and low. Electric rates in Vermont have increased only 3.7% since 2011, which is slower than overall inflation, while New England average rates rose 12.3% and U.S. average rates have increased 5.6%. Vermonters on average now pay the second-lowest electric rates in New England.

The plan emphasizes the importance of efficiency and conservation. This includes continuing improvements in demand-side thermal and electric efficiency and conservation. It includes efficiencies gained by using new electric technologies (heat pumps, electric vehicles) that are substantially more efficient than previous technologies. It also includes efficiency in electric generation that comes from shifting toward cost-effective wind, solar, and hydroelectric power, and away from wasteful power plants that send heat up smokestacks. The focus on strategic electrification reinforces the shift toward distributed energy resources that support our grid, increase resilience, and reduce infrastructure costs.

Meeting these energy goals will also set the state on a path to meet its greenhouse gas emission reduction targets. We have a moral and economic imperative to take substantial and consistent action to reduce greenhouse gas emissions to mitigate global climate disruption, while also preparing Vermont for its impacts. **This CEP establishes two goals for reduction in greenhouse gas (GHG) emissions from Vermont's energy use, both of which are consistent with the renewable energy and energy use goals:**

- **40% reduction below 1990 levels by 2030, and**
- **80% to 95% reduction below 1990 levels by 2050.**

The Renewable Energy Standard (RES) in Act 56 of 2015 has set Vermont on a path to better alignment among the growing sources of renewable energy generation, along with the right to claim that renewable energy toward Vermont's objectives. Responsible land use choices will enable us to meet our energy goals while advancing the state's land use goals of compact centers surrounded by working lands. Local energy supply from farms and forests also supports the financial sustainability of our working landscape.

Finally, this CEP recognizes that energy and land use choices directly impact Vermonters' health, through both environmental and economic means. Meeting these energy goals will require infrastructure that enables active lifestyles, coupled with improved air quality from reduced combustion of fossil fuels combined with increased use of advanced wood heat technologies. Energy affordability also means increased winter comfort, with profound health benefits.

Continuous assessment of the performance of energy programs and policies against these goals will inform the state's energy policy development.

Infrastructure matters

Energy use in homes and businesses is overwhelmingly determined by the physical characteristics of those buildings and the appliances or industrial processes they contain. Transportation energy use is fundamentally driven by the locations of homes and businesses, along with the public, private, and commercial infrastructure that includes our roads, sidewalks, transit systems, and vehicles. Electric generation facilities are themselves substantial physical infrastructure, as is the engineering feat of the electric grid that connects them.

Infrastructure choices are therefore in many cases energy choices; and many energy policies and programs become effective by shaping those choices. The long-lived nature of most of the built environment makes it more challenging to quickly transform our energy system. Initial choices in construction of roads, buildings, and other infrastructure have outsized impacts compared with subsequent modifications to that infrastructure. Getting it right the first time matters.

Chapter 5 of the CEP identifies and discusses the land use impacts of energy choices, and the energy impacts of land use choices.

When compared to legacy infrastructure, clean energy infrastructure tends toward options that reduce operating costs but cost more to construct or purchase up front. Examples include solar, wind, and hydroelectric generators, which have no fuel cost; building retrofits, which improve the quality of a building shell while lowering its operating costs; and locating a new building in a compact center, which can have higher land costs while lowering transportation energy needs. These investments can pay off over their lifecycle — but they require financing tools to show that advantage over legacy options. Financing tools can also better align the interests of those developing infrastructure with those who will pay to operate it.

Chapter 6 of the CEP identifies and discusses cross-cutting actions and approaches to clean energy finance.

A distributed and connected energy future

Our legacy fossil-fuel-based energy system is also a centralized system. Large central electric generators produce power that flows great distances along power lines to consumers; fossil fuels are produced in a few locations around the world, then shipped or piped to wholesalers and then to consumers. This CEP embraces a different vision: a distributed energy future in which a significant portion of Vermont's energy is produced near where it is consumed, and which is shaped by many coordinated actions by distributed energy users, rather than through singular central control. This alternate vision is possible thanks to the increasing availability of cost-effective distributed electric generation technology, such as solar PV, along with the increasing opportunity to store electric and thermal energy, and the communications overlay that comes from near-universal broadband and smart grid deployment combined with "smart" appliances and other end-use energy control technologies. Wood energy use for heat is the original distributed energy, and advanced wood heat technologies rejuvenate this option as well.

This shift to a more local and distributed energy system is apparent throughout this CEP, but the shift's most prominent impact is in the electric sector. As energy efficiency and demand response have matured as resources, we have seen that efficiency can change long-term forecasts, while demand response can be dispatched — like a generator — to meet peak loads. New generation has come online from resources like wind and solar power that have no operating costs, are generally smaller in capacity, and are distributed in many locations around the distribution grid. Electric-energy storage technologies are maturing quickly, as are technologies for automating and aggregating control of many different kinds of end uses (beyond the water heater controls that have been deployed for decades). Electric vehicles and heat pumps present new challenges and opportunities. The proliferation of information technology tools throughout the grid provides the opportunity to optimize operations, with significant yet uncertain potential to contain costs. Regulatory transformation may also be required in order to reduce costs and improve system performance by capturing value from diverse distributed resources.

Fostering innovation and entrepreneurship

Vermont has the opportunity to capitalize on its leadership in clean energy. We are already home to the largest number of clean energy jobs, as a fraction of all jobs, of any surveyed state: 4.8% of Vermont employees (16,231 people) participate in the clean-energy economy[1]. Companies that get their start here are well-positioned to expand and compete in other states and countries as the economies in those locations also shift toward clean energy. This CEP embraces the idea of Vermont as a starting point, and as a test bed for new technologies.

Vermont's scale is conducive to assembling the parties needed to try something new, earning approval, and proceeding to action quickly. Even Vermont's largest energy companies are small on a national scale and retain the nimbleness that small size can bring; and Vermont's recent energy history is one of collaboration between firms, state and federal agencies, and non-governmental partners. At the same time, we have a cutting-edge energy industry and infrastructure that entrepreneurs and innovators can engage with — including a statewide smart grid, thousands of distributed electric generators, world-leading efficiency and regulatory expertise, and a burgeoning advanced wood heat industry.

Where we've been, where we are, and where we're going

The 2011 CEP established a goal of meeting 90% of the state's energy needs through renewable sources by 2050. It also proposed taking steps to virtually eliminate our dependence on petroleum. The 2011 plan spurred vibrant and ongoing discussion statewide, along with significant actions. These actions include:

- Passage of Act 56 establishing a Renewable Energy Standard;
- The Thermal Efficiency Task Force and two Clean Energy Finance Summits;
- Updated building energy codes and a Vermont residential building label;
- Pilots of new financing programs, including the Heat Saver Loan;
- Signing of the multi-state Zero Emission Vehicle memorandum of understanding;
- Strengthening the state's land use designation programs;
- Expansion of the Standard Offer program, while lowering the cost of new contracts by more than 60%; and
- Expansion of net metering to 15% of peak load, and an ongoing process to design a sustainable net metering program.

Chapter 2 of this CEP discusses each of these successes in more detail.

Energy is a substantial portion of home and business expenses. Vermonters will spend about $2.4 billion this year on energy. This total cost is split between electricity (35%), fuels for heat and industrial processes (25%), and fuels for transportation (40%). This total reflects today's relatively low oil and natural gas prices. To the extent that Vermont remains dependent on those fuels, if and when their costs rise, our total energy costs will rise as well, especially for heat and transportation.

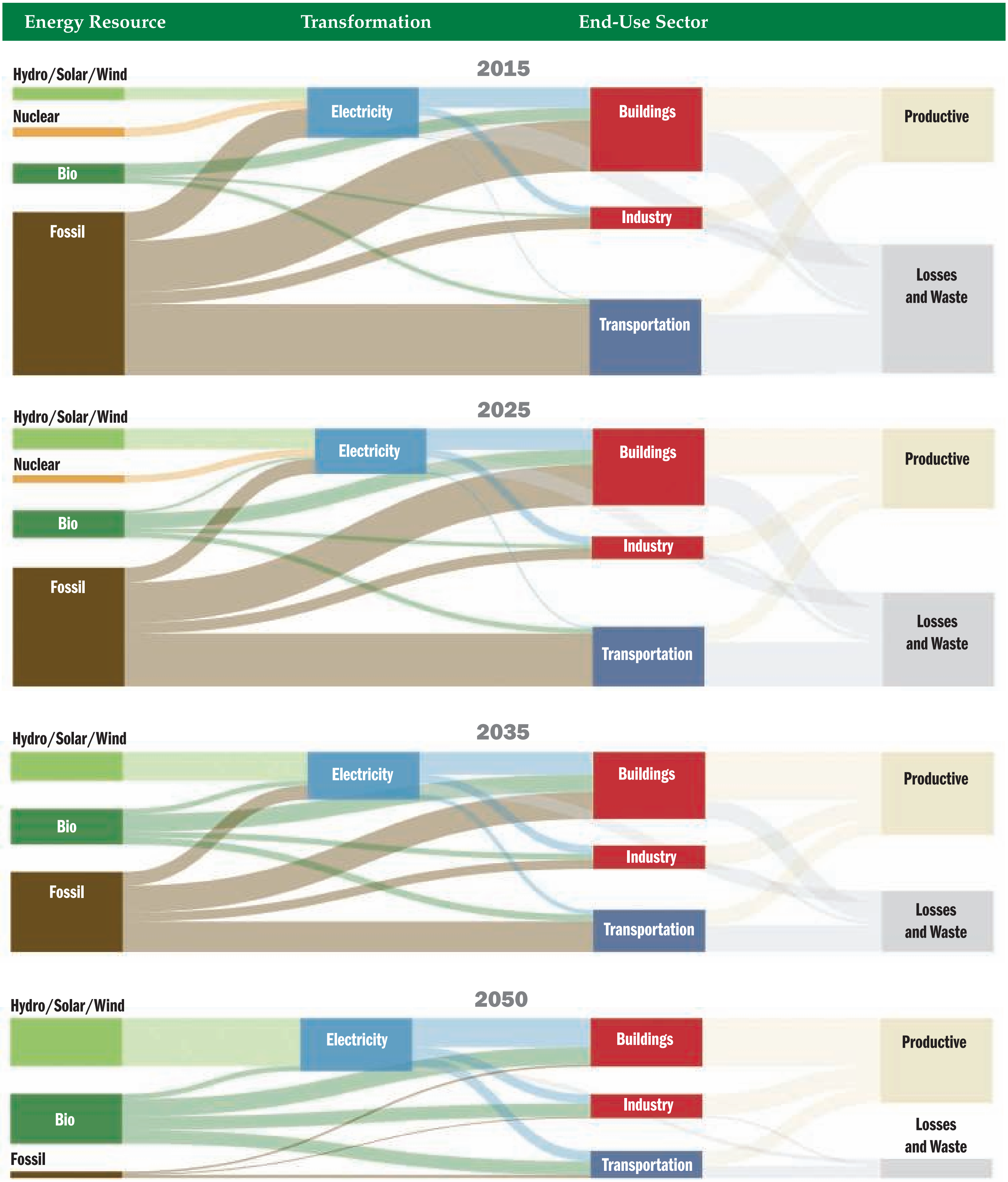
Energy is also the dominant source of Vermont's greenhouse gas emissions — 80% of our emissions result from energy use. Here transportation dominates, with 47% of all GHG emissions. Reducing our emissions, and maintaining affordability, go hand-in-hand with a transition to renewable energy and a reduction in energy waste.

In 2015, Vermont will get about 16% of our total energy from renewable sources. Renewability varies by sector: electric power is about 45% renewable, while building heat is about 20% renewable, and transportation is only about 5% renewable. Figure ES-1 shows the estimated total energy flows for 2015, 2025, 2035, and 2050. Each portion of this graphic begins with primary energy on the left side, divided into four types: hydro/wind/solar (non-combustion-based renewable resources); bio (combustion-based renewables); nuclear electricity; and fossil fuels. The height of each band corresponds to the amount of energy from each source. Some of each resource then flows to

1 *Vermont Clean Energy Industry Report 2015,* (Department of Public Service), publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/CEDF/Reports/VCEIR%20 2015%20Final.pdf

Figure ES-1

Vermont energy flows in 2015, with an illustrative path forward to 2025, 2035, and 2050.



be transformed into electricity, while some combustible resources are used directly in each end-use sector (buildings, industry, and transportation). Losses and waste from electric generation are totaled on the far right, along with losses and waste from each of the end-use sectors: buildings, industry, and transportation.

Figure ES-1 illustrates one path forward that would meet of the CEP's quantitative energy use, renewability, and GHG emission goals for 2025, 2035, and 2050. The productive energy at each time period increases, reflecting Vermont's growing economy and improving quality of life. Meanwhile, total energy use declines significantly as waste and losses are reduced. Fossil fuel use falls throughout, but is particularly displaced between 2035 and 2050 by the combination of electricity and bioenergy (which is concentrated in uses where electrification is not possible or cost-effective). Electric end-use energy increases significantly, while primary energy used to generate electricity grows only slightly.

This figure illustrates three ways to reduce total energy use without compromising energy service:

1. **Continuing improvements in demand-side thermal and electric efficiency and conservation.** Efficiency and conservation neutralize the increase in energy demand associated with increases in population, the growth in building-space square footage, and the growth in industrial output, all of which are assumed to increase at historically consistent rates. The largest efficiency impact comes from improvements in building shells which reduce the need for building heat delivered by any means.

2. **Fuel switching away from combustion technologies to more efficient electric-powered technologies.** Heat pump and electric vehicle technology is capable of supplying the same level of energy service as its combustion-based counterparts, with a third or less of the site energy requirements.

3. **Declining source energy requirements of electricity generation.** As more of the state's electric power supply is generated by solar, wind, and hydro resources, which do not produce the unusable waste heat associated with combustible generation fuels, the overall source-energy requirements to power new heat pump and electric vehicle loads also decline. Thus, even with growing consumption of electricity, per capita consumption of primary energy declines even faster.

Strategies to meet our goals

There are four general types of policies that work together to drive change: market-based policies, information and access, strategic investment, and codes and standards.

Market-based policies (also called price-based policies) establish a new market, or shape the prices in an existing market, in order to harness market forces to achieve a policy goal. Examples include cap-and-trade systems, renewable portfolio standards, and carbon taxes. Such policies are intended to align market forces and societal objectives by sending a price signal to end-use consumers that would encourage consumption of a renewable or efficiency alternative that is societally preferred, but would otherwise be less cost-competitive.

Information and access policies address the real-world shortcomings of a market-based policy instrument. These policies enhance markets by providing information, technical assistance, or access to capital, including financing. They also address problems of misaligned incentives, such as between landlords and tenants. They are aimed at ensuring that consumers have access to efficient markets, where they can easily identify and act on options that offer the lowest lifecycle costs.

Strategic investment may be required to spur and shape the early adoption of new technologies and their markets. Research and development may yield examples on which to build. Policies can build markets for nascent technologies. Strategic investment that is directed at the highest-cost necessary technologies for achieving Vermont's goals can reduce those costs. This allows price-based policies to drive optimization without unreasonable direct price impacts.

Codes and standards — such as building energy codes, appliance efficiency standards, vehicle fuel economy rules, and land use plans — serve to avoid lost efficiency opportunities in long-lived products and infrastructure, using established technology. Codes and standards are appropriately applied only when cost-effective on a lifecycle basis.

The RES established by Act 56 of 2015, combined with Vermont's participation in the Regional Greenhouse Gas Initiative (RGGI), has built a foundation of market-based policies in the electricity sector, while leveraging the progress being made here to reduce fossil fuel use in other sectors. The RES is expected to reduce the state's GHG emissions by an amount approximately equal to a quarter of the emission reductions required to meet the state's 2050 goals, while saving Vermonters hundreds of millions of dollars in energy costs — significantly advancing our economic and environmental goals.

The recommendations established in this CEP reflect integration across the four policy approaches to driving sustainable energy system change. Of particular note is a recommendation, further detailed in chapter 4, regarding market-based GHG emission reduction policy:

> *Vermont should work with other states and provinces in our region, building upon existing regional initiatives, to investigate and pursue options for market-based GHG emission policies that integrate with the other*

Public engagement, education, and support

Vermont can only meet the goals established in this plan with the support and active involvement of individuals, businesses, non-governmental organizations, and all levels of government. Individual decisions — about where to live, what car to buy (or whether to buy a car at all), what appliances to buy, whether and how to weatherize your home or invest in renewable energy — will have a significant impact in shaping Vermont's energy future. The same is true of business decisions. While public policy has affected and will continue to affect these choices, and they have real public impact, they are fundamentally private decisions.

Public support for utility energy supply choices is also essential for these organizations to make the necessary investments on behalf of their customers. Those choices need to reflect the state's policy of least cost energy planning – including economic and both local and global environmental costs – in order to build and sustain public support. The pace of growth of in-state renewable electricity development has not produced unanimous support, and there is more work to be done to foster processes and choices that will engender greater support in the future. The land use principles identified in chapter 5, along with the specific recommendations in chapters 11 and 13, are intended to help shape the path forward. This path will involve continuous refinement as we learn from experience, develop best practices, and accommodate new technologies.

This plan encourages public education and opportunities for local engagement and action from a total energy perspective. Beyond the siting-related recommendations just mentioned, key recommendations include:

- Learning from and expanding on the Regional Planning Commission energy planning pilot now underway to develop robust and comprehensive regional energy plans that build from a shared set of goals and reflect local knowledge and preferences;
- Creating and supporting creation of public information resources on renewable energy and energy efficiency in Vermont;
- Growing and strengthening local energy expertise, particularly through support of town energy committees and energy coordinators who play an essential role in driving local energy engagement and action; and
- Supporting K-12, higher education, and vocational education initiatives to bring energy into the classroom, including learning from successful efforts in other jurisdictions.

approaches described in this CEP, and consistent with the principles regarding revenue recycling, pace, equity and competitiveness detailed in this plan.

The structure of the CEP reflects the energy flows shown in Exhibit ES-1, moving right to left. Sections address the challenges, opportunities, and strategies for each topic, consistent with the guiding goals. The CEP concludes with the incorporation of the State Agency Energy Plan, which identifies the state's path forward as an energy consumer and producer who can lead by example.

Heat in buildings and industry

One fifth of the energy used to heat Vermont's buildings and to provide process heat in industrial applications comes today from renewable sources, primarily wood. The CEP establishes a goal of increasing that portion to 30% by 2025, through both efficiency and increased use of renewable fuels. Achieving this goal is compatible with efforts to meet the state's existing statutory building efficiency goals — including weatherizing 80,000 of the state's homes by 2020. This particular goal looks increasingly out of reach, but the efforts to meet it have spurred development of new tools that will help the state meet similar objectives: reduced energy costs combined with increased value and quality of the state's building stock. The technological and programmatic tools exist to transform new construction so that all new buildings are "net zero" by 2030.

Meeting 30% of the remaining heat demand from renewable sources, including wood and other solid biomass, liquid or gaseous biofuels, and heat pumps powered by renewable electricity, means significantly increasing the use of both bioenergy and heat pumps. One sample pathway involves increasing the use of solid and liquid biofuels by 20% by 2025, on the way to doubling wood's share of building heat by 2035. Meanwhile, installing about 35,000 cold-climate heat pumps by 2025 would begin the transformation of remaining building heat to renewable electricity.

Vermont's primary challenges to achieving these goals are:

- Market failures such as lack of information, lack of access to capital, lack of valuation of building efficiency in the real estate market, and split incentives between landlords and tenants.
- Lack of consistent public or private funding at the quantities required to meet the statutory goals.
- An older building stock, 30% of which was built before 1940.

These challenges are particularly steep for low-income Vermonters, many of whom rent housing in older buildings, have no or almost no ready capital, and have no appetite for or ability to borrow money.

Vermonters also face a lack of fuel choices — although here as elsewhere there is real progress. This progress includes improved wood heating technologies and availability of locally produced wood pellets; increased availability and understanding of cold-climate air-source and ground-source heat pumps; and expanding access to natural gas via pipeline and truck. New biomass-powered district heating systems are being demonstrated in Montpelier, in the new Waterbury state office complex, and in other building complexes around the state.

Critical tools and recommendations moving forward include:

- Take a whole-building approach to buildings as systems, recognizing the interaction of all their components and the value of partnerships between experts who would address buildings in different ways: electric and thermal, heating systems, building shells, controls, and access to capital through financing.
- Develop a seamless "one-stop shop" for customer information and coordinating projects. Improve customer and market information regarding building heat through a statewide information clearinghouse, and building-specific information through building labels.
- Continue to work with stakeholders to develop the path to all new buildings being built to net-zero design by 2030.
- Fully fund and maximize the effectiveness of existing thermal efficiency programs, particularly those serving low-income populations, as well as new utility programs to meet RES Tier 3 obligations.

Transportation

As a rural state, Vermont's economy and its people depend on reliable transportation. This requires energy – about one-third of Vermont's total energy – and its associated economic, environmental, and health consequences. Transportation is responsible for nearly half of Vermont's greenhouse gas emissions, and in 2013 more than $1 billion per year left the state to buy fuel. The primary challenges in transportation transformation include:

- The long lifetime of the built environment, so impacts on land use are both slow and essential.
- Vehicle and fuel markets are national, and there are few proven state policy or programmatic levers to shape customers' vehicle choices, especially in the face of customer uncertainty regarding new fuels and vehicle technology.
- Electric vehicle technology is advancing rapidly, but there are not yet EVs to meet all Vermonters' diverse vehicle desires (especially in view of concerns over EV range, and many Vermonters' desire for four-wheel or all-wheel drive).
- Vermont's rural communities lack the density to support frequent and affordable public transit service.

Only 6% of transportation energy is renewable today, and this is primarily in the form of corn-based ethanol blended in gasoline. Sustainably increasing this fraction significantly, while reducing overall energy use, will require a different approach. Meeting a goal of 10% renewable energy in transportation by 2025, on the way to at least 80% by 2050, will depend on four primary strategies:

- **Reduce transportation energy demand through smart land use.** Striving toward Vermont's land use goal of maintaining the historical settlement pattern of compact centers surrounded by rural countryside is highly compatible with a goal of keeping vehicle miles traveled per capita below 2011 levels.

- **Shift transportation away from single-occupancy vehicles** through the promotion of other options, including transit, walking, biking, carpooling, and telework.

- **Electrify and increase the efficiency of light-duty vehicles.** Plug-in vehicle registrations in Vermont have grown by a factor of 10 in three years, but the market is still in its early stages. The plan sets a goal of 10% of the vehicle fleet powered by electricity by 2025. Vermont's Zero Emission Vehicle (ZEV) Action Plan includes evaluating potential ways to incentivize the purchase and lease of EVs, promoting consumer awareness and understanding of the benefits of EVs and fuel efficient vehicles, and deploying charging infrastructure at workplaces and key public locations. The State of Vermont's own vehicle fleet already includes more than a dozen plug-in vehicles. That number will continue to grow, and the state is hosting public charging infrastructure.

- **Increase the efficiency of heavy-duty vehicles and power them with renewable fuels**, such as advanced liquid or gaseous biofuels. Expanded fueling infrastructure and increasing fuel availability are the primary immediate required steps. Improving the lifecycle renewability of biofuels will be essential to securing their long-term place in Vermont's renewable future.

Electricity

Vermont has made consistent progress in recent years on reducing the environmental impacts of our electricity consumption while maintaining stable and affordable electric rates. Electric rates in Vermont have increased by 3.7% since 2011, slower than overall inflation, while New England average rates rose by 12.3% and U.S. average rates have increased by 5.6%. Vermont's electricity is currently 45% renewable; with the RES that fraction will increase to

55% in 2017, and it will continue to climb to 75% renewable in 2032. Vermont will also be home to an increasing portion of the generation that serves our load, with the RES requiring 10% of 2032 electricity to come from small, renewable generators connected to our state's electric grid.

As discussed earlier, the electric grid is in the midst of a transformation away from a centralized, one-way electric grid to an integrated grid where both demand and supply adjust moment by moment to maintain balance on the grid. This paradigm offers new opportunities to optimize grid infrastructure decisions and to allow for significant increases in electric use while lowering both overall energy costs and electric rates. Electricity is expected to play a major role in the clean energy transformation of both heating and transportation — and the hardware, software, and regulation of the grid need to be ready.

The primary recommended strategies for electric power in this CEP are:

- Continue to acquire all reasonably available cost-effective energy efficiency.
- Manage electric load using active means, including new control technologies in concert with expanded access to and adoption of smart rates.
- Plan carefully to meet all three tiers of the RES in a least-cost manner. Strive to lower both energy bills and electric rates.
- Engage actively in regional grid planning and policy-making, recognizing the significant impact that regional choices can have on Vermont.
- Maximize opportunities to encourage siting of renewable energy on the built environment, in already disturbed areas, or co-located with other uses in order to minimize conflicts with other land uses and users.
- Take advantage of opportunities to incrementally transform our utility regulations to reflect the reality of distributed energy resources and an integrated grid. This includes explicitly welcoming innovation and entrepreneurship by utilities and their partners.

Energy Resources

Chapters 12 and 13 of this CEP describe in detail each of the energy resources – renewable or not – that powers Vermont. End-use energy efficiency is a key resource that can meet demands without the use of any supply resources, often at lower cost and with fewer environmental and health impacts. As such, it is and should remain the first option for meeting energy service demands. But energy efficiency cannot meet all energy needs — so supply resources are required.

These two chapters examine these resources:

- Solar
- Wind
- Wood and other solid biomass
- Liquid biofuels
- Methane from on-farm and non-farm digesters as well as landfills
- Hydropower
- Coal
- Petroleum
- Nuclear
- Natural gas

For each resource, the chapter examines these aspects:

- Overview
- State of the market
- In-state resources
- Out-of-state resources
- Siting and permitting
- Benefits
- Challenges
- Strategies and recommendations

This CEP recognizes that there is no single path for Vermont to attain the goals, or to enact the strategies identified here or discussed in detail within the rest of the plan. Required instead will be incremental policy changes, along with progress on education, finance, and innovation. Vermont must work with both public and private sectors, including with utilities, to advance these objectives in cost-effective, affordable, efficient, and innovative ways, and to encourage each and every citizen to do what they can to help all of Vermont achieve a transformative energy future.

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(Title 3 V.S.A. § 2291)

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1 Preface

1.1 Objectives for the Comprehensive Energy Plan

This Comprehensive Energy Plan (CEP) has three primary objectives. First, the CEP is intended to inform readers of the many challenges and opportunities facing Vermonters in our mutual efforts to maintain a safe, reliable, affordable, environmentally sound, and sustainable energy supply across all sectors — electricity, transportation fuels, and heating and process fuels. Because the CEP is both a policymaking and a reference tool, readers can use it to learn more about the energy initiatives going on in the state and how Vermont's energy issues relate to regional, national, and even international developments. It attempts to raise awareness among both policymakers and the public about critical concerns that relate to energy issues.

Second, the CEP recognizes the dynamic and interrelated nature of energy policy, while examining current efforts to address our energy challenges. The 2011 CEP established a goal of meeting 90% of the state's energy needs through renewable sources by 2050. Coupled with this, it proposed taking steps to virtually eliminate our dependence on petroleum. Since its release, the plan has created vibrant discussion statewide, along with significant actions, and this updated CEP builds on that ongoing dialogue.

The Vermont economy has continued to grow following the financial crisis, and the state has among the lowest unemployment rates in the country — but we do face longer-term demographic challenges. Clean energy jobs, in particular, have been a source of growth for the state. At the same time, federal and state laws are evolving and are altering the policy framework under which energy planning occurs. Given the complexity of energy issues and their interrelatedness with other challenges facing government, this 2016 CEP attempts to take an integrated look at energy decisions regarding not just electric power, but also heating and transportation.

Finally, the CEP makes specific recommendations on ways in which the state can support, guide, expand, or take the critical next steps to help lead Vermont, the region, and the nation into a sustainable, affordable renewable-energy future. Combining the long-term goal of obtaining 90% of the state's total energy needs from renewable sources by mid-century with the statutory goal of 25% renewable by 2025 (10 V.S.A. § 580(a)), this CEP establishes the following set of goals:

- Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 2050.
- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050.
- Meet these three end-use sector goals for 2025: 10% renewable transportation, 30% renewable buildings, and 67% renewable electric power.

The context and implications of these goals are discussed in Chapter 4 and throughout the plan. The CEP recognizes, however, that there is no single, lockstep path that may help Vermont attain these goals. Incremental policy changes will instead be required, along with progress on education, finance, and innovation.

This plan reflects the challenges and initiatives in play at the time of its publication. The issues are complex, and the policy, economic, and scientific frameworks surrounding them are changing rapidly. New challenges, new initiatives, and new events that contribute to a greater understanding of energy policy and climate change occur monthly, weekly, sometimes even daily. The CEP attempts to provide a comprehensive look at these challenges and opportunities in this moment, and offers recommendations for making progress going forward.

This CEP reflects insights gained from numerous reports, meetings, and conversations with stakeholders and other members of the public since the publication of the 2011 CEP. It also draws on input and expertise from the agencies of Natural Resources; Transportation; Agriculture, Food & Markets; Commerce and Community Development; and Human Services. Its implementation will continue to be shaped by public feedback following its release.

1.2 Statutory Goals and Requirements

Vermont law requires the Department of Public Service (DPS) to produce a CEP for the state covering at least a 20-year period. 30 V.S.A. § 202(b) states:

> (1) The DPS, in conjunction with other state agencies designated by the governor, shall prepare a comprehensive state energy plan covering at least a 20-year period. The plan shall seek to implement the state energy policy set forth in section 202a of this title. The plan shall include:
>
> (1a) A comprehensive analysis and projections regarding the use, cost, supply, and environmental effects of all forms of energy resources used within Vermont.
>
> (1b) Recommendations for state implementation actions, regulation, legislation, and other public and private action to carry out the Comprehensive Energy Plan.

The CEP is designed to serve as an actionable framework for moving forward toward the goals defined in the statute. At the highest level, Vermont's statutory policies include these major goals:

- 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. (30 V.S.A. § 202a(1))

- To identify and evaluate, on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least-cost integrated planning, including efficiency, conservation and load management alternatives, wise use of renewable resources, and environmentally sound energy supply. (30 V.S.A. § 202a(2))
- To give effect to the policies of section 202a of Title 30: to provide reliable and affordable energy, and assure the state's economic vitality, it is critical to retain and recruit manufacturing and other businesses, and to consider the impact on manufacturing and other businesses when issuing orders, adopting rules, and making other decisions that affect the cost and reliability of electricity and other fuels. Implementation of the state's energy policy should:
    - Encourage recruitment and retention of employers providing high-quality jobs and related economic investment, and support the state's economic welfare; and
    - Appropriately balance the objectives of this section with the other policy goals and criteria established in this title. (30 V.S.A. § 218e)
- To promote the state energy policy established in § 202a of this title by:

    (1) Balancing the benefits, lifetime costs, and rates of the State's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the State flow to the Vermont economy in general, and to the rate paying citizens of the State in particular.

    (2) Supporting development of renewable energy that uses natural resources efficiently and related planned energy industries in Vermont, and the jobs and economic benefits associated with such development, while retaining and supporting existing renewable energy infrastructure.

    (3) Providing an incentive for the State's retail electricity providers to enter into affordable, long-term, stably priced renewable energy contracts that mitigate market price fluctuation for Vermonters.

    (4) Developing viable markets for renewable energy and energy efficiency projects.

    (5) Protecting and promoting air and water quality in the State and region through the displacement of those fuels, including fossil fuels, which are known to emit or discharge pollutants.

    (6) Contributing to reductions in global climate change and anticipating the impacts on the State's economy that might be caused by federal regulation designed to attain those reductions.

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

(8) Promoting the inclusion, in Vermont's electric supply portfolio, of renewable energy plants that are diverse in plant capacity and type of renewable energy technology. (30 V.S.A. § 8001)

The DPS is also required to produce an Electric Plan per 30 V.S.A. § 202 Electrical Energy Planning, which states, in part:

> (b) The Department shall prepare an electrical energy plan for the state. The plan shall be for a 20-year period and shall serve as a basis for state electrical energy policy. The electric energy plan shall be based on the principles of "least cost integrated planning" set out in and developed under section 218c of this title. The plan shall include at a minimum:
>
> (1) An overview, looking 20 years ahead, of statewide growth and development as they relate to future requirements for electrical energy, including patterns of urban expansion, statewide and service area economic growth, shifts in transportation modes, modifications in housing types and design, conservation and other trends and factors which, as determined by the director, will significantly affect state electrical energy policy and programs;
>
> (2) An assessment of all energy resources available to the state for electrical generation or to supply electrical power, including among others, fossil fuels, nuclear, hydro-electric, biomass, wind, fuel cells, and solar energy and strategies for minimizing the economic and environmental costs of energy supply, including the production of pollutants, by means of efficiency and emission improvements, fuel shifting, and other appropriate means;
>
> (3) Estimates of the projected level of electrical energy demand;
>
> (4) A detailed exposition, including capital requirements and the estimated cost to consumers, of how such demand shall be met based on the assumptions made in subdivision (1) of this subsection and the policies set out in subsection (c) of this section; and

(5) Specific strategies for reducing electric rates to the greatest extent possible in Vermont over the most immediate five-year period, for the next succeeding five-year period, and long-term sustainable strategies for achieving and maintaining the lowest possible electric rates over the full 20-year planning horizon consistent with the goal of maintaining a financially stable electric utility industry in Vermont.

(c) In developing the plan, the Department shall take into account the protection of public health and safety; preservation of environmental quality; the potential for reduction of rates paid by all retail electricity customers; the potential for reduction of electrical demand through conservation, including alternative utility rate structures; use of load management technologies; efficiency of electrical usage; utilization of waste heat from generation; and utility assistance to consumers in energy conservation.

The recently enacted Act 56 establishes a Renewable Energy Standard (RES) (30 V.S.A. § 8004 and 8005), which requires electric power to be:

- 55% renewable in 2017, rising 4% every three years to 75% in 2032; and
- 1% from distributed generators connected to Vermont's electric grid in 2017, rising 0.6% per year, to 10% in 2032.

The RES also requires electric utilities to reduce fossil fuel use by their customers by an amount equivalent to 2% of retail electric sales in 2017, rising two-thirds of a percent per year to 12% by 2032.

Meanwhile, the plan must also take into account complementary state policies set forth in other titles of our statutes that concern greenhouse gas emissions and energy:

- It is a goal of the state, by the year 2025, to produce 25 percent of the energy consumed within the state through the use of renewable energy sources, particularly from Vermont's farms and forests. (10 V.S.A. § 580(a))
- To reduce emissions of greenhouse gases 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, in order to make an appropriate contribution to achieving the regional goals of reducing emissions of greenhouse gases from the 1990 baseline by:

  (1) 25 percent by January 1, 2012;

  (2) 50 percent by January 1, 2028;

- (3) if practicable using reasonable efforts, 75 percent by January 1, 2050. (10 V.S.A. § 578(a)) To increase energy efficiency of buildings:

(1) To improve substantially the energy fitness of at least 20% of the state's housing stock by 2017 (more than 60,000 housing units), and 25% of the state's housing stock by 2020 (approximately 80,000 housing units).

(2) To reduce annual fuel needs and fuel bills by an average of 25% in the housing units served.

(3) To reduce total fossil fuel consumption across all buildings by an additional one-half percent each year, leading to a total reduction of 6% annually by 2017 and 10% annually by 2025.

(4) To save Vermont families and businesses a total of $1.5 billion on their fuel bills over the lifetimes of the improvements and measures installed between 2008 and 2017.

(5) To increase weatherization services to low-income Vermonters by expanding the number of units weatherized, or the scope of services provided, or both, as revenue becomes available in the home weatherization assistance trust fund. (10 V.S.A. § 581)

We look to the Vermont statutes as our primary source of goals, but we also look to actions by state groups and groups at the regional level as sources of further direction. The Vermont Climate Cabinet and the Governor's Council on Energy and the Environment are two examples of state government groups that can provide valuable guidance for establishing a Comprehensive Energy Plan.

Other sources of regional direction for this CEP were the climate change commitments made in the New England Governors and Eastern Canadian Premiers Climate Change Action Plan, adopted in August 2001; the Northeastern International Committee on Energy (NICE); the creation of the Regional Greenhouse Gas Registry (RGGR) by the Northeast States for Coordinated Air Use Management (NESCAUM); and the Regional Greenhouse Gas Initiative (RGGI), a cooperative effort by nine Northeast and mid-Atlantic states to design and participate in a regional cap and trade program covering carbon dioxide emissions from power plants in the region. The Agency of Transportation, the Agency of Natural Resources, and the Public Service Board have signed on to an agreement with 11 Northeast states and the District of Columbia to reduce greenhouse gas emissions from the transportation sector through the Transportation Climate Initiative[1] (TCI).

When setting forth our energy goals, we are also taking into account the mandates and policy directives of the federal government. The U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) issue joint rules to establish fuel economy and greenhouse gas standards for motor vehicles. EPA has recently published the Clean Power Plan, regulating greenhouse gas emissions in the electric sector. The 2015 Paris Agreement commits the U.S. and nearly every other

[1] Transportation and Climate Initiative of the Northeast and Mid-Atlantic States, www.transportationandclimate.org/

country in the world to significant greenhouse gas emission reductions over the next half century, with the goal of limiting global temperature rise. Federal appliance standards are another area that directly impacts Vermont, and federal transmission reliability standards and transmission planning mandates affect state energy policy. Finally, the DPS also reviews federal research and policy directives, such as the Obama administration's *Blueprint for a Secure Energy Future* (released in March 2011) and the federal interagency *Quadrennial Energy Review* (released in April 2015).

Vermont is not an island. Although we can set ambitious goals to move ourselves away from fossil fuels for the health of our economy, our environment, and our people, we can reach these goals only if state policies align with the interests and initiatives of our private sector and the national government. For example, this CEP calls for a significant increase in focus on transportation energy usage — but we will not successfully reach our transportation energy goals unless electric vehicles and biofuels truly take hold nationwide, conventional fuel standards are significantly improved, and transportation infrastructure funding is decoupled from petroleum usage. Nevertheless, we can and should set a direction for Vermont that moves toward a more sustainable future, while simultaneously advocating for policy alignment with the private sector and the national government.

1.3 The 20-Year Electric Plan

Pursuant to 30 V.S.A. § 202, the DPS is assigned to serve as the state's electric utility planning agency, ensuring utility service at least cost to ratepayers when implementing other public policies of the state. This CEP embodies the requirements of 30 V.S.A. § 202 and functions as the Vermont 20-Year Electric Plan.

The Electric Plan serves as a basis for state electric energy policy. It is based on the principles of least-cost integrated planning, as defined in Vermont statute at 30 V.S.A. § 218c(a)(1). The Electric Plan includes a 20-year outlook, an assessment of all energy resources available to the state for electricity generation or to supply electric power, estimates of electric energy demand, and specific strategies for reducing electric rates. Among other objectives, it also considers the protection of public health and safety and the preservation of environmental quality.

It is important to note that since the enactment of 30 V.S.A. § 202, regional electric markets have restructured, and electricity is now sold in a regionally competitive market. Moreover, the Vermont Legislature has directed all utilities to develop and carry out individual Integrated Resource Plans (IRPs), reviewed by the DPS and approved by the Public Service Board, to meet customers' needs for energy services "at the lowest present value life cycle cost, including environmental and economic costs" (30 V.S.A. § 218(c)). Although the Electric Plan continues to guide and inform utility planning, the IRP model and the regional electric market have, in many respects, altered the need for a statewide electric plan as it originally existed. Given that an increased electrification of many energy services — especially heating and transportation — may be necessary to achieve the state's energy policy objectives, a full integration of electric planning into this CEP is required.

1.4 The Approach to CEP Development and Public Engagement

This Comprehensive Energy Plan is the result of intensive collaboration among state agencies, coupled with substantial public involvement. As directed by the statutory mandate and the ongoing efforts of the governor's Climate Cabinet, the CEP reflects the collective efforts of senior leaders and staff from state agencies and departments, along with input submitted to the Department of Public Service by Vermont citizens and stakeholders. The DPS received nearly 800 public comments as it developed this CEP.

The DPS is Vermont's energy agency. As part of this process, the DPS opened conversations with agency partners about the process, issues, policies, and programmatic cross-connections and opportunities for coordination. Vermont government partners included the Agency of Natural Resources; Agency of Transportation; Agency of Commerce; Agency of Agriculture, Food & Markets; Agency of Human Services; Agency of Administration; Department of Buildings and General Services; Department of Taxes; and Department of Health. These conversations continue as the agencies advise, plan, work with one another, and challenge one another's thinking on issues currently under consideration in state government. The content and recommendations of this CEP rely heavily on the subject-matter expertise in these agencies.

In May 2011, Governor Shumlin formed the Vermont Climate Cabinet. It is composed of the secretaries of the Agencies of Natural Resources, Administration, Agriculture, Food & Markets, Commerce and Community Development, and Transportation, as well as the commissioners of the Departments of Economic Development, Housing and Community Affairs, Buildings and General Services, and Public Service. This group has played an important role in overseeing the implementation of the 2011 CEP, and will continue in that role as this CEP moves forward.

To help inform the CEP, we also engaged the Regulatory Assistance Project to provide analytic support and expertise on future utility regulatory structures and business models, informed by RAP's work in other U.S. and foreign jurisdictions.

1.4.1 Public Process

To engage the public regarding the state's planning efforts and to update its understanding from the 2011 CEP, the DPS designed a two-phase public engagement process. Phase I sought input on the crafting of the initial public review draft through mid-July 2015, and Phase II gathered input on the released draft.

Phase I began in May 2015 with the release of a request for information, including a number of specific questions. The DPS then organized a set of four half-day stakeholder workshops in late June and early July. These workshops addressed energy efficiency and conservation, electric grid and utility issues, energy supply resources, and transportation and land use. Each meeting was framed by relevant facts and analysis, and consisted primarily of breakout group discussions focused on particular topics or sectors of relevance to the CEP update. Throughout July, meetings that were organized in collaboration with the Vermont Energy and Climate Action Network (VECAN), town energy committees, and regional planning commissions provided more opportunities for Vermonters to learn about energy and share their perspectives on the CEP. These meetings were held in Woodstock (July 9), Middlebury (July 16), Manchester (July 20), and St. Albans (July 23). All of the materials presented at stakeholder and public meetings were posted on the CEP website (energyplan.vt.gov).

Throughout Phase I, the DPS also collected input from the public via emails, letters, and a survey tool on the CEP website. The process brought in comments representing a wide range of perspectives and suggestions, all of which have informed this draft CEP. The approach has been to consider all public input, whether received verbally at public hearings or in written comments via email, online form, or mail.

The DPS began Phase II of the public engagement process with the release of the Public Review Draft CEP in September 2015 and its formal public comment period. Again, the DPS collected input from the public via emails, letters, and a survey tool on the project website. Along with soliciting written comments, the process included five public hearings around the state to solicit detailed suggestions for incorporation into this final plan. These meetings were held in Lyndonville (October 7), Essex (October 13), Montpelier (October 21), Westminster/Bellows Falls (October 26), and Rutland (October 29).

The public process facilitated thought-provoking discussion, and the comments received were both passionate and informative. They were also anything but unanimous, on any point. While some perspectives or suggestions as represented in the comments may be either directly or indirectly reflected in the plan, others may not be. Regardless, all voices were welcome throughout the public process, no matter the perspective, and each comment was reviewed and thoughtfully considered. This public input will continue to inform the DPS as we move into plan implementation.

1.5 What the CEP Does Not Do

The CEP is a forward-looking document, but it is not intended to address all issues. The CEP does not prescribe outcomes or make recommendations for specific projects, and it does not analyze specific projects that are pending before the Vermont Public Service Board. The CEP also does not presume to know all the choices Vermont will make to reach the goals set forth herein, or the exact timeline by which some will be achieved. For example, although the CEP sets forth models for a high-renewables and high-efficiency electric portfolio, it is the precise mix of resources actually built or contracted by our utilities over time that will ultimately dictate their cost and GHG emission profile.

The CEP is also not Vermont's climate change plan. The goals and recommendations included here are consistent with, and will be a key component of, meeting the state's greenhouse gas emission reduction goals, and the CEP reflects planning for some impacts of climate change on the energy system. However, the CEP does not present a comprehensive look at Vermont's non-energy-related GHG emissions or its other climate adaptation planning needs.

1.6 Organization of the 2016 CEP

The result of this extensive planning work is this 2016 CEP. The executive summary summarizes the current energy picture and lays out the CEP's goals and vision for the future. The main text contains the details behind the recommended goals, initiatives, and key programs as they relate to the energy services of heat, transportation, and electric power, and to the many resources that can provide energy to meet those needs. The CEP includes 14 chapters, organized by topic; it provides background on history and current use, as well as supply and demand issues, for particular forms of energy, along with analysis and recommendations.

Energy efficiency and conservation emerge as the central policy focus, as they apply directly to all forms of energy use and generation, including electricity, thermal energy, process fuels, and transportation. The CEP also focuses on greater use of renewable energy in all sectors, to help ensure energy independence and environmental sustainability. Recommendations address state implementation actions, regulation, legislation, and other public and private actions.

The dynamics involving energy and the environment change monthly, sometimes even more frequently — and the CEP must be responsive to the changes that are taking place. Sectors that were formerly quite distinct are beginning to converge (e.g., electricity with both heat and transportation). The DPS intends to keep working closely with the Climate Cabinet, which will continue to be a steward of the CEP.

2 Progress toward the Recommendations and Goals of the 2011 Comprehensive Energy Plan

The four years since the completion of the 2011 CEP have seen significant progress in advancing its recommendations and goals. Existing and new programs have continued Vermont's leadership in encouraging energy efficiency across all fuels, and in fostering local development of new renewable energy supply. Progress in the next six years will build on foundations established in the last four; throughout this CEP, recommendations reflect the progress already made and identify the next steps for further implementation. Following discussion of cross-cutting actions that reflect progress across multiple energy services and summaries of major energy legislation, this chapter summarizes the highest-impact actions the state has achieved since the 2011 CEP in three energy services: heat, transportation, and electric power.

The programmatic and policy progress that this chapter identifies has been enabled by the continuing development of technologies that have expanded the range of cost-effective clean energy options for Vermonters. These include a significant decline in the cost of distributed electric generation — especially from solar photovoltaic generators, whose installed costs have fallen by almost 30% since 2011[2]. There are at least a dozen models of plug-in electric vehicles available today that were not available when the last CEP was published, and many more have been announced for the next couple of years. Heat pump heating systems suitable for Vermont have expanded from ground-source to a growing array of affordable cold-climate air-source options. Meanwhile, electric rates in Vermont have increased by 3.7% since 2011, slower than overall inflation, while New England average rates rose by 12.3% and U.S. average rates have increased by 5.6%[3].

Across state government, the continued interagency partnerships established through the 2011 CEP process and the subsequent work of the Governor's Climate Cabinet have embedded joint actions, such as the ZEV Action Plan described in section 2.3.1. The State Agency Energy Plan, developed jointly with this CEP, also draws on that interagency partnership to demonstrate state leadership by example.

2.1 Major Legislative Actions

The Vermont Legislature has passed one or two significant pieces of energy legislation each year since 2011. In addition, numerous other bills, including the budget and transportation bills, have noticeable

[2] Data from small-scale solar PV systems supported by the Clean Energy Development Fund.

[3] U.S. Energy Information Administration. Comparisons are between calendar year 2011 and September 2014-August 2015, the most recent 12-month stretch available.

energy implications. This section summarizes only those recent acts that are primarily concerned with energy, rather than all acts with any energy implications.

2.1.1 Act 56 of 2015: Renewable Energy Standard

Act 56 of 2015[4] established a Renewable Energy Standard (RES) for Vermont electric utilities, while repealing the Sustainably Priced Energy Enterprise Development (SPEED) program. The renewable portfolio standard (RPS) created by this Act requires electric utilities to increase the portion of renewable energy they sell to Vermont customers to 55% in 2017, rising over time to 75% in 2032. This is the RES's *Tier 1* requirement. *Tier 2* requires that an increasing portion (1% in 2017, climbing to 10% in 2032) of electric energy comes from small (less than 5 MW) electric generators that are connected to and support Vermont's distribution grid, or that help to avoid costly transmission upgrades. An RPS with these features was an explicit recommendation of the 2011 CEP.

Act 56 also creates a separate, *Tier 3* energy transformation obligation that rises from 2% in 2017 to 12% in 2032 (except that small municipal utilities will not have an obligation until 2019). A utility may meet this requirement through additional distributed renewable generation, or through energy transformation projects that result in net reduction of fossil fuel consumption by the utility's customers. Examples of these projects could include building weatherization; air source or geothermal heat pumps and high-efficiency heating systems; industrial-process fuel efficiency improvements; increased use of biofuels; biomass heating systems; and electric vehicles or related infrastructure. While Act 56 primarily addresses electric utilities and will have profound effects on electric power supply and demand, it is also a cross-cutting policy tool because of its potential impact on efficiency and fuel choice for heating and transportation.

While the exact paths that utilities take to meet the RES obligations, particularly Tier 3, are unknown, the DPS estimates that the RES as a whole will reduce Vermont's net energy bills by hundreds of millions of dollars, and will have limited impacts on electric rates. Strategic electrification that results from energy transformation projects has the potential to lower electric rates by more completely utilizing our electric infrastructure. Meeting the RES requirements will also reduce Vermont's GHG emissions by approximately 15 million tons by 2032, putting the state on a path to meet one quarter of its emission reduction goal by 2050. Careful implementation of the RES is a prime and recurring thread throughout this updated CEP.

Act 56 also addressed the siting of electric generators, especially solar PV. It allows towns hosting generators to automatically become parties to siting proceedings before the Public Service Board. For solar PV, it established the first statewide standards for the setbacks of generators from roadways and property lines. It empowered towns to set screening requirements for solar PV, as long as those standards were no more stringent than would be required for other commercial development and would not

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[4] http://legislature.vermont.gov/assets/Documents/2016/Docs/ACTS/ACT056/ACT056 As Enacted.pdf

preclude the construction or operation of the generators. It also established the Solar Siting Task Force, discussed in section 2.5.4 below.

2.1.2 Act 125 of 2012 and Act 99 of 2014: Net Metering

The last four years have seen two significant acts regarding net metering: Act 125 of 2012[5] and Act 99 of 2014[6]. Act 125 expanded the simple registration process for solar PV permitting to systems up to 10 kW (from 5 kW), and allowed customers with demand or time-of-use rates to take greater advantage of the ability to net meter. Act 99 raised the program capacity cap to 15% of utilities' peak demand, from 4%. It also raised the registration form threshold to 15 kW, while lowering the solar credit by one cent per kWh for systems over 15 kW. Act 99 also established a process, underway now, for the PSB to refine the now-mature program for a sustained and equitable future through stakeholder input and rulemaking.

2.1.3 Act 89 of 2013: Thermal Efficiency

Act 89 of 2013[7] adopted a number of provisions intended to strengthen the thermal efficiency of Vermont buildings, informed by the work of the Thermal Efficiency Task Force. It required or advanced several informational tools, including a "clearinghouse" for thermal efficiency information and continued development of building energy labels. It established authority for the DPS to adopt "stretch codes" for building energy, which would then be required for residential development through Act 250. It further improved building energy code compliance by requiring that certificates of occupancy may not be provided for residential or commercial construction without demonstrated compliance with the building energy codes.

2.1.4 Act 170 of 2012: Standard Offer and Renewable Energy Goals

Act 170 of 2012[8] enacted several changes proposed in the 2011 CEP, whose publication immediately preceded the 2012 legislative session. Act 170 expanded the Standard Offer program by 77.5 MW, allowed both electric utilities and independent developers to bid for and build Standard Offer projects, and established a market-based process for the setting of contract prices. It also adopted goals of 55% renewable electricity by 2017 and 75% by 2032 (targets which subsequently became requirements through Act 56 of 2015), with explicit regulatory requirements for consistency with these targets. Act 170 also required what became the Total Energy Study.

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[5] legislature.vermont.gov/assets/Documents/2012/Docs/ACTS/ACT125/ACT125%20As%20Enacted.pdf

[6] legislature.vermont.gov/assets/Documents/2014/Docs/ACTS/ACT099/ACT099%20As%20Enacted.pdf

[7] legislature.vermont.gov/assets/Documents/2014/Docs/ACTS/ACT089/ACT089%20As%20Enacted.pdf

[8] legislature.vermont.gov/assets/Documents/2012/Docs/ACTS/ACT170/ACT170%20As%20Enacted.pdf

2.2 Cross-Cutting Progress

A lasting impact of the 2011 CEP is the development of a total energy perspective on achieving Vermont's energy goals. Meeting 90% of the state's energy needs from renewable sources by 2050 will require careful use of energy, and careful choice of fuels, across all end uses. The Total Energy Study brought that perspective to long-term energy analysis, while the Renewable Energy Standard in Act 56 will both increase renewable energy and reduce fossil fuel use. This updated CEP builds on this total energy foundation, while associated regional energy planning pilots bring it to the regional scale, and clean energy finance provides necessary capital.

2.2.1 Total Energy Study

The 2011 CEP recommended that the Legislature and DPS explore the possibility of a Total Energy Standard; the Legislature then required[9] a two-year study of policies and programs that would meet the state's GHG and renewable energy goals in an "integrated and comprehensive manner." The resulting Total Energy Study[10], completed by the DPS in December of 2014, identified and evaluated promising policy and technology pathways, as well as raising questions for further analysis and consideration.

The fundamental conclusion of the Total Energy Study is that Vermont can achieve its GHG emission reduction goals and its renewable energy goals while maintaining or increasing the state's economic prosperity. However, to do so will require significant changes in energy policy, fuel supply, infrastructure, and technology.

2.2.2 Enhanced Regional Energy Planning

The DPS has partnered with three regional planning commissions (RPCs) — Bennington, Two Rivers-Ottauquechee, and Northwest — to advance a total energy approach to regional energy plans, consistent with the goals and approach embodied in both the 2011 CEP and this update. This project is underway, and will be complete in 2016. Each RPC, working with the Vermont Energy Investment Corporation, will model pathways to 90% renewable energy within its region, and will identify particular regional goals and actions on heat, transportation, and electric power. The updated plans will also include a mapping component, identifying promising areas for different kinds of renewable energy supply technologies. The DPS hopes the development and adoption of these revised plans will enable a bottom-up approach to energy planning that will complement the state-led CEP structure.

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[9] Via Act 170 of 2012 (www.leg.state.vt.us/docs/2012/Acts/ACT170.pdf) and Act 89 of 2013 (www.leg.state.vt.us/DOCS/2014/ACTS/ACT089.PDF)

[10] publicservice.vermont.gov/publications/total_energy_study

2.2.3 Clean Energy Finance Summits

The 2011 CEP identified finance as a key leverage point for the development of clean energy in Vermont. The DPS, Agency of Commerce & Community Development, and partners organized statewide summits on clean energy finance that were convened by Senator Bernie Sanders and Governor Peter Shumlin in April 2012 and June 2013. The primary purpose for these events was to advance clean energy development in Vermont, and to build stakeholder engagement in advancing priority energy-finance recommendations in the public and private spheres. Each event was a working session, during which participants shared perspectives on clean energy finance from the national level down to the local and offered their input on how to move ahead.

Both events contributed to the momentum for clean energy by addressing the finance aspect of meeting the state’s energy goals. Discussions covered a range of topics, such as the status of federal tax credits, the role of debt and equity in project finance, and steps needed to attract to the clean energy industry the kinds of long-term, lower-cost capital that are available to other mature industries. While many of the issues can be addressed by the federal government, others — such as development of on-bill finance models and efficient technology deployment systems — are amenable to innovation at the state and local levels.

2.3 Progress on Heat in Buildings and Industry

Since the enactment of Act 92 in the 2007/2008 legislative session, energy efficiency programs have facilitated the installation of efficiency improvements in just under 18,300 Vermont housing units. The pace of building improvements, however, continues to lag behind what is required to achieve the Legislature's goals of 80,000 weatherized homes by 2020 and 0.5% per year reductions in fuel use across all buildings. Analysis resulting from the 2011 CEP has identified the scale of traditional efficiency programs required to achieve that goal, and the power of other tools, such as building codes and new financing options, to increase the energy fitness of Vermont’s buildings. Recent reductions in the price of fossil fuels have enabled some immediate energy cost savings, but long-term savings will require improvements in building shells and heating systems.

2.3.1 Thermal Efficiency Task Force

The Department of Public Service created the Thermal Efficiency Task Force (TETF) in 2012, in response to the 2011 CEP's recommendation that Vermont “develop a detailed plan for facilitating a simple, integrated, and comprehensive statewide whole-building approach to thermal energy efficiency that will put us on the path toward meeting the building efficiency goals set forth in statute” (10 VSA § 581). The TETF addressed residential, commercial, and industrial fuel use.

With 65 members representing 45 organizations, the Task Force included a wide range of diverse stakeholders. It met over the course of 2012, and issued an extensive report of findings and recommendations in January 2013.

The report includes a detailed analysis of the projected benefits to Vermont businesses and families, and to the state as a whole, of a full investment in reaching the building efficiency goals. These benefits include:

- An increase in gross state product of $1.47 for every $1 invested. Incremental energy efficiency programs alone result in an increase in gross state product of $1.80 for every $1 invested.
- A net increase of nearly 800 job-years within Vermont's economy.
- Prevention of 6.8 million tons of carbon dioxide-equivalent emissions from entering the atmosphere, over the investment lifetime. This equates to taking 1.26 million passenger vehicles off the road for one year.

To achieve these benefits, key recommendations included:

- Implementing a statewide clearinghouse to provide consumers with easy access to information on making energy improvements.
- Building the confidence that promised energy savings will be realized.
- Increasing the use of financing to offset upfront costs.
- Developing industry partnerships to build the trained workforce needed to scale up efficiency work.
- Increasing consistency of approach and standards across programs.

The report also included recommendations for the public funding necessary to scale up this effort. The Task Force estimated that meeting the state's building efficiency goals would require new annual public program funding that would rise from $27 million in 2014 to $39.6 million in 2020. The Task Force based its recommendations on the assumption that most of the needed resources will have to come from private, not public, funds. As a result, the report calls for every dollar in public funding to leverage nearly two dollars of investment from the private sector. To date, the public funding called for in this recommendation has not been made available, and it is anticipated that the building efficiency goals set forth by statute will not be met.

2.3.2 Building Energy Codes

The DPS recently updated Vermont's residential and commercial energy codes. The update process started at the beginning of 2014, and the new codes went into effect on March 1, 2015. The new codes are based on the International Energy Conservation Code (IECC); Vermont was the first state to adopt the 2015 IECC. The DPS also adopted the first Vermont residential stretch code, which goes into effect December 1, 2015,[11] and it has developed commercial stretch energy guidelines, which will be used by the Natural Resources Board for commercial Act 250 projects.

[11] The DPS was given the authority to 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). Act 89 also states that the stretch code shall apply to all Act 250 projects and can be adopted by individual municipalities.

Both the residential base and stretch energy codes incorporate renewable energy into Vermont's energy codes for the first time, by enabling renewable energy to be used to meet the target Home Energy Rating Scores for compliance. Also for the first time, the residential stretch code and commercial stretch energy guidelines have electric-vehicle charging requirements. The residential requirement applies to multifamily developments of 10 units or more, and for both residential and commercial developments it calls for a socket capable of providing either a Level 1 or Level 2 charge for 4% of the total parking spaces (rounded up to the nearest whole number).

Also, as called for in the 2011 CEP, the DPS developed an Energy Code Compliance Plan in 2012, outlining an approach for achieving 90% compliance with energy codes by February 1, 2017. The plan recommends a number of priorities to advance the state's energy code compliance efforts, including the use of COMcheck (software) documentation as part of the Act 250 permit process; improved coordination between the DPS and the Department of Public Safety; coordination and support of municipalities' code activities; formation of an Energy Code Collaborative; and securing funding for up to three full-time positions to support outreach, compliance, and enforcement activities. Many of the items recommended in the plan have been carried out by the DPS and other partners. Code compliance has also been identified as a priority issue for discussion by the newly formed Energy Code Collaborative.

2.3.3 Building Energy Labeling

In 2013 and 2014, Vermont stakeholders, with support from the Legislature, created Building Energy Working Groups for both the residential and commercial sectors. These groups have the goal of developing a consistent format for disclosing the energy performance of buildings, and selecting one or more tools to generate an energy rating. Each working group also completed and submitted reports to the Legislature, describing the comprehensive assessment and analysis it had completed on the issues that relate to labeling buildings for their energy performance.

The Residential Building Energy Labeling Working Group decided that an asset-based, MMBtu/year-based score should be used, to be generated thorough the U.S. Department of Energy's free energy scoring software. A draft label has been developed and is being pilot tested in 2015, with the goal of fully launching the label through the state Energy Efficiency Utilities and Weatherization Program by the beginning of 2016.

The Commercial Building Energy Labeling Working Group, which also considered multi-family residential buildings, decided to use an operations-based rating generated through EPA's Energy Star Portfolio Manager. The group also recommended convening an advisory committee to address multiple identified issues, and to work toward rolling out a commercial building energy rating and label.

2.3.4 "Heat Saver Loan" Thermal Efficiency Finance Pilot

Launched in July 2014 by Governor Shumlin, the Thermal Energy Finance Pilot project (TEF Pilot) uses funding supplied by the DPS, Vermont Low Income Trust for Electricity (VLITE), and DOE to provide interest rate buy-down and loan loss reserves to reduce credit risk at participating financial institutions. Vermont State Employees Credit Union and Opportunities Credit Union, selected via competitive solicitation in 2014, both offer the program's Heat Saver Loan with low-interest rates and terms up to 15 years for qualified borrowers. Borrowers must work with a qualifying contractor that participates in the Efficiency Excellence Network (EEN), a venture of Efficiency Vermont (EVT). The pilot is slated to run into 2016, after which the DPS will evaluate the impact and prospects for continuation of this and/or similar finance initiatives. For more information on this and other finance programs, see Chapter 6.

2.4 Progress in Transportation

Between 2011 and 2014, Vermonters reduced their gasoline use by nearly 6%. The range of factors that contributed to the decrease includes increased vehicle efficiency and Vermonters choosing methods of travel other than single-occupancy vehicles. After decades of growth in vehicles miles traveled (VMT), and a doubling of the number of cars and trucks on Vermont roadways between 1975 and 2009, total VMT in Vermont declined by almost 10% between 2003 and today — including a nearly 2% decline between 2011 and 2013. Public transit ridership rose more than 5% between 2011 and 2014, along with a 17% increase in rail ridership at Vermont stations.

Electric vehicles have taken off in Vermont, from 88 passenger cars at the first inventory in July 2012 to 1,046 in October 2015. As of December 2015, there are 99 EV charging stations in the state, including 17 "fast chargers" that can charge an EV's battery in less than half an hour.

2.4.1 Zero Emission Vehicle Rules and Action Plan

In February 2014, the Agency of Natural Resources updated its air emission rules for low emission vehicles to match the current California standards, as called for by the 2011 CEP. These rules adopt the next generation of zero emission vehicle (ZEV) requirements, covering model years 2018-2025, and will require that annual sales in Vermont of all-electric and plug-in hybrid electric vehicles exceed 4,500 by 2025. In concert with those rules, Vermont joined seven other states in an October 2013 Memorandum of Understanding, the ZEV MOU. These states pledged to work together to get 3.3 million zero emission vehicles on the road by 2025 through coordinated and individual actions.

Vermont is participating in the 8-state ZEV action plan, and has also developed its own. The Vermont ZEV Action Plan identifies state-specific actions and strategies to grow the ZEV market in Vermont in a manner that is consistent with state climate and renewable energy goals, ZEV program requirements, and the commitments in the MOU. The actions pledged in that plan are reflected in the recommendations of this CEP: they include promoting the availability and marketing of electric vehicles, exploring consumer purchase incentives, and leading by example through the incorporation of electric vehicles into the state vehicle fleet.

2.4.2 Compact Land Use

Since 2011, statutory changes have strengthened the five state land use designation programs, which identify downtowns, village centers, growth centers, and neighborhoods. Strengthening these programs was a key strategy recommended by the 2011 CEP. The improvements resulted in a surge in the number of new designations, as well as new funding and partnerships to encourage and support compact development. These include increased tax incentives for new and existing buildings; grants to build electric-vehicle charging stations in downtowns and villages; creating a new funding priority in the Agency of Natural Resource's Brownfield, Water, and Wastewater programs; enhanced Efficiency Vermont incentives; and targeted funding and programs from the Agency of Transportation. Updates were also made to Act 250's 9(L) criterion to promote growth in compact centers and discourage auto-oriented development outside these areas.

The total number of municipal plans that meet the state's land use goals increased. All 11 regional plans were reviewed and updated to assure they meet statutory requirements; and, as described in section 2.1.3, three regional planning commissions partnered with the DPS, Vermont Energy Investment Corporation (VEIC), and their member communities to update their energy plans.

2.5 Progress in Electric Power

The largest single legislative or programmatic achievement in the electric power sector since the 2011 CEP is the passage of the Renewable Energy Standard in Act 56. This will likely result in increased use of electricity for both heat (heat pumps) and transportation (electric vehicles). Meeting the resulting electric energy demand, and limiting the resulting impact on Vermont's electric system and associated costs, will be a continuing concern for electric utilities and their regulators in the coming years.

If any required upgrades to the grid infrastructure itself can be limited by effective load management, increased retail sales of electricity will result in lower electric rates than would otherwise be expected. The last four years have seen advances in the tools that increase the potential for effective load management, while at the same time increasing cost-effective local investment in electric generation.

2.5.1 Energy Efficiency Utility Performance

Vermont's two electric energy efficiency utilities (EEUs) met performance expectations in the 2012-2014 performance period. Together, their actions during that time saved over 3,500 GWh over the lifetime of efficiency measures, and delivered a 6% reduction in 2014 energy use. They also reduced Vermont's electric peak demand by 4% (42 MW), saving ratepayers in capacity, regional transmission service, and future infrastructure costs.

Targeted energy efficiency has successfully deferred infrastructure needs in St. Albans and in the Susie Wilson Road area of Essex. The Vermont System Planning Committee, coordinating the work of distribution, transmission, and energy efficiency utilities, has shown that efficiency combined with distributed generation and demand response can explicitly avoid the need for hundreds of millions of dollars' worth of transmission infrastructure that would otherwise be required to maintain reliability.

2.5.2 Standard Offer Program Expansion

As recommended by the 2011 CEP, Act 170 of 2012 expanded the Standard Offer program to 127.5 MW from 50 MW and introduced a market-based pricing mechanism. Prices for long-term Standard Offer contracts under the program's original formulation exceeded 24 cents per kWh for solar photovoltaics (solar PV), while responses to the 2015 request for proposals were as low as 10.96 cents per kWh. At the same time that program costs for solar PV have fallen by more than a factor of two, the Standard Offer program has also enabled the expansion of non-solar technologies, such as hydroelectric, small wind, and food waste anaerobic digestion, and has provided continued support for farm digesters.

2.5.3 Net Metering

Vermont's net metering program has been subject to numerous expansions and refinements since it was first established in 1999. Two Acts since 2011 have further expanded the program, and have established a structure that will enable it to continue on a sustainable basis. Permitted net metered generation capacity has risen, from 18 MW at the end of 2011 to almost 120 MW as of late 2015. Several utilities have net metered capacity at or approaching the 15% cap. In December 2105, the Public Service Board requested comment on a revised net metering rule, which would take effect in January 2017.

2.5.4 Siting Policy

Increasing the in-state development of renewable energy generation will require a sustainable process for permitting and siting that generation. To that end, the governor issued Executive Order 10-12[12], establishing the Energy Generation Siting Policy Commission to survey best practices for siting approval of electric generation projects, and for public participation and representation in the siting process.

The commission published its final report[13] on April 30, 2013. It proposed a package of recommendations built on robust energy planning, particularly at the regional level, along with a simplified, tiered approach to siting; increased opportunities for public participation; changes to the procedures to increase transparency, efficiency, and predictability; and updated guidelines for the protection of health and the environment. While the commission's recommendations have not been enacted, they have served to inform the scope of the regional planning pilot discussed in sections 2.1.3 and 2.3.2.

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[12] sitingcommission.vermont.gov/sites/cep/files/Siting_Commission/Homepage/EO%2010-12%20Energy%20Gen%20Siting%20Policy%20Commission.pdf

[13] Energy Siting Policy Commission, *Siting Electric Generation in Vermont* (2013), sitingcommission.vermont.gov/sites/cep/files/Siting_Commission/Publications/FinalReport/Final%20Report%20-%20Energy%20Generation%20Siting%20Policy%20Commission%2004-30-13.pdf

As of the drafting of this CEP, the Solar Siting Task Force[14] established by Act 56 of 2015 had not completed its work. This Task Force has considered the cumulative impacts of solar PV development, the challenges to the siting process resulting from the scale and pace of solar PV deployment, and various options for municipal and regional planning to meaningfully inform the siting process. It is considering both regulatory and programmatic solutions. The Task Force is expected to produce its final report by January 2016, and the Legislature is expected to consider its suggestions in the coming session.

[14] solartaskforce.vermont.gov

3 Energy Policy in its Economic, Environmental, and Health Context

The Comprehensive Energy Plan strives to further the state's economic, environmental, and human health goals. It recommends taking a broad view of the positive and negative impacts of energy generation and consumption, to ensure that our decisions carefully consider human health impacts and environmental issues like air and water quality, along with economics, and avoid compromising them. Reaching our energy goals is important; but some pathways will have greater net positive impacts than others on the economy, the environment, and human health.

This CEP recognizes that economic, environmental, and health ideals can be in conflict, and that implementing a policy or program requires striking balances. No one set of ideals trumps another; we strive instead to achieve them all. When there is consistency among these goals and an action will positively affect them all, it deserves greater priority. When there is a conflict between principles or policies, the plan notes the need for careful deliberation to find the path that develops the greatest positive benefit and minimizes the negatives.

This chapter describes ideals that can be applied broadly to energy projects, technologies, or policies under consideration. The sections here provide high-level guidance, intended to help decision makers consider the potential impacts of energy choices and policies, and how these choices both align with and help to achieve other non-energy state policy objectives, or create tension with them.

Why does consideration of principles related to health, the environment, and the economy matter? Ideally, new energy options would not only generate the power or fuel needed for the state, but would also improve quality of life, support a robust economy, and retain fully functional, healthy ecosystems. But in practice, the energy choices considered in this CEP may pose potential tradeoffs. How do the impacts on health, the environment, and the economy compare between energy policies or technologies? Are there options that pass muster across all three domains? What mitigation options are available?

The discussion that follows provides a starting place for thinking about these impacts. Many energy policy options and approaches impact multiple areas; the inclusion of an action as an example in one area does not imply that it is not also relevant elsewhere.

3.1 A Vibrant and Equitable Economy

The following priorities provide lenses for considering impacts related to the vibrancy of the Vermont economy resulting from potential energy projects or policies.

Priority: **Ensure an affordable and stable cost of living** through improvements in the energy fitness of Vermont homes, strategic electrification, focusing development in compact villages and urban centers, and the substitution of price-volatile fossil fuels with renewable alternatives that have lower long-term costs.

Over the past two decades, despite very little growth in energy consumption, the cost of energy has been absorbing an increasing share of Vermonters' personal income, mostly as a result of increasing prices for the large amounts of gasoline and distillates that Vermonters rely on for transportation and heating uses. Displacing those fuels with more efficient options, including transformative electric technologies, provides the same level of energy service at lower overall cost and with less consumer exposure to commodity price swings. Locally supplied wood energy is among the most economical options for Vermonters.

Lower energy bills enable greater discretionary spending that supports local employment and incomes, while also increasing the value of the home and strengthening the viability of the community. Capital access is required in order to realize the benefits of a lower total cost of living. Connecting local supplies of investment and finance capital to Vermont clean energy activities can help fuel progress toward multiple state policy objectives.

Priority: **Ensure an affordable and stable cost of doing business** through improvements in commercial and industrial building and process energy efficiency, strategic electrification, and the substitution of price-volatile fossil fuels with renewable alternatives that have lower long-term costs.

In recent years, on average across industries, growth in Vermont business energy costs has begun to outpace overall business revenue growth. This is a departure from the trend over the last three decades, when sales volumes had consistently proven sufficient to cover energy cost increases. Reducing and stabilizing Vermont businesses' long-term energy costs frees up potential investment capital, enables wage increases, and improves businesses' competitive position. Manufacturers, in particular, see energy costs' impact on competition. In addition, marketing Vermont's agricultural products or reducing the costs for local farming operations via energy-related activities supports the state's overall goals of strengthening farms and food production. Economic vitality also depends on continuity of access to energy, and prompt restoration in case of interruption.

Priority: **Increase entrepreneurship opportunities** by supporting market demand for renewable energy and energy efficiency services, as well as encouraging research and commercialization of new energy services and technologies.

Most of the business revenue associated with Vermont energy expenditures currently finds its way to out-of-state suppliers of fossil fuels. Redirecting Vermont's energy spending to in-state suppliers of biomass products, distributed power, and efficiency services invites innovation, productivity, and expansion in local businesses that can result in greater market share and export earnings. For example, expanding opportunities to market low-grade wood as an energy fuel source for clean, efficient, advanced wood heating supports existing forest products, expands opportunities for secondary forest product development, and improves the economic stability of forestland.

A commitment to stewardship values enhances the Vermont brand and increases the attractiveness of Vermont for residents and entrepreneurs. Willingness to take a chance on a new product, technology, or practice contributes to a healthy innovation ecosystem. Community ownership of energy infrastructure (including through cooperatives and municipal utilities) fosters local engagement and sense of having a stake in the community's future.

Priority: **Improve labor market conditions** by creating well-paying jobs in industries that supply renewable energy commodities and energy efficiency services.

Wage growth in Vermont has slowed significantly over the past few decades, as it has across the nation, leaving households increasingly dependent on debt to maintain purchasing power. Over the past 25 years, the Vermont labor force has witnessed the replacement of tens of thousands of relatively well-compensated manufacturing jobs by a comparable number of less well-paid service jobs in health care, social assistance, and education industries. Widespread deployment of weatherization and efficiency efforts, utilization of native biomass resources, and movement toward distributed electricity generation will each open up new employment opportunities in existing and emergent industries.

Priority: **Ensure an equitable distribution of benefits and burdens** by assisting those least able to pay the increasing costs of energy and the upfront capital costs for efficiency and fuel switching investments.

The increase in Vermonters' energy cost burden over the last 25 years has fallen most heavily on the lowest-income households. On average, Vermonters spend around 15% of their wage and salary earnings on energy purchases, up from approximately 11% in 2000. For those with the least means, energy costs can absorb 30% of income or more. Renters face particular challenges, given landlords' lack of incentive to fund efficiency improvements. Reducing the energy bills of those with relatively less discretionary income increases household financial stability while enabling greater comfort and health.

Priority: **Maintain revenue to support government functions** by replacing the reduction in income from the sale of taxable fuels, such as motor fuels, with appropriate new revenue sources.

As with other economic sectors, the activities related to the delivery of energy services are often a source of funding for government functions through taxation or fee collection. The most obvious of these is the tax on the sale of motor fuels to support the state's transportation infrastructure. Other less significant examples include the fees collected on the sale of heating oil for the cleanup of leaking storage tanks, the Gross Receipts Tax for the Vermont Home Weatherization Assistance Program Fund, and the Uniform Capacity Tax on solar PV generators.

Vermont's path to a clean energy future will result in some fundamental shifts in several economic activities; one large shift is a reduction in the sale of taxable fuels. To counter that loss, there will be increases in the activities associated with renewable energy production and the services for supporting energy efficiency programs. As these shifts are first envisioned and ultimately implemented, the consideration of state revenues is necessary so as not to increase the burden on other existing revenue sources to support government services.

3.2 Healthy Ecosystems and a Sustainable Environment

The following priorities provide lenses for considering impacts related to ecosystem health and long-term environmental sustainability stemming from potential energy projects or policies.

Priority: **Reduce greenhouse gas emissions,** consistent with the state's emission reduction goals, by reducing fossil fuel use and efficiently using renewable energy sources.

Energy use is responsible for more than 83% of Vermont's GHG emissions. Energy project-related emissions of GHGs and other air pollutants can vary considerably, depending on the fuel and/or specific technologies used, and priority should be given to those that minimize both GHG and other air pollutant emissions. Human-driven GHG emissions are the main driver of climate change, which leads to increased precipitation events that add higher loads of sediment, nutrients, and pollutants to our waterways, while also causing economic harms. Higher temperatures associated with climate change exacerbate problems with nutrient-polluted waterways.

Priority: **Reduce local air pollutants,** including particulates and toxins, by using efficient and clean combustion technologies, along with shifting away from fossil fuels.

Combustion's harmful byproducts affect ecosystems and human health. Vermont can prioritize energy activities that reduce or eliminate combustion of fuels, followed by using low-emitting renewable fuels to diminish air quality impacts. Efficient generation (e.g., advanced combined heat and power technologies) and efficient use (e.g., weatherization, efficient vehicles) with relatively low emissions of air pollutants are preferred over older, less efficient, higher-emitting technologies or practices.

Priority: **Take a global and life-cycle perspective** to the analysis of costs and benefits.

All currently viable energy technologies and fuels, both renewable and non-renewable, emit GHGs and other pollutants over their full life cycle. For global pollutants, reducing emissions anywhere along the life cycle has comparable climate benefits. Using consistent methodology, we can account for relative upstream/life-cycle emissions and other impacts attributable to our energy choices, and use that knowledge to make choices that minimize overall emissions and other life-cycle impacts.

Priority: **Retain healthy, functional forest and agricultural systems** through responsible use of forest and agricultural resources for energy and non-energy-related applications.

> Forest health is a prerequisite to a sustainable supply of wood for fuel and other forest products, and to the continuation of other forest values and benefits. Sustainable forest management maintains in-forest carbon storage and uptake, while ensuring that this resource is truly renewable. This includes reducing forest fragmentation and edge conditions, retaining regional wildlife corridors and habitat connectivity, decreasing risks to forests from invasive species, and supporting species and age diversity to build resilience against climate disruption. Modern wood-energy technology uses the resource efficiently, improving energy yield and reducing emissions. Maintaining functional agricultural soils is important to produce locally grown food, support our growing value-added agricultural industry, and grow energy crops that can all benefit Vermonters.

Priority: **Maintain water quality throughout Vermont's ecosystems** through responsible land and water use.

> Land use best practices improve water quality by reducing erosion and stormwater runoff, while maintaining and enhancing agricultural productivity, lowering fertilizer use, and improving flood resilience. Dams, including those used for hydroelectric production, can impact water quality. Investment in dams to install or increase hydroelectric production should also maintain or enhance the hydrodynamic properties of the river. Using water efficiently also reduces the energy needed to treat and move water.

Priority: **Optimize land use choices** to minimize local and global environmental impact, including balancing land use among competing needs in the state for energy, non-energy development, housing, transportation, working lands for agriculture and forestry, and other purposes.

> This includes the siting of energy generation, transmission, and distribution infrastructure, as well as the siting of residential, commercial, and industrial development that will require transportation energy for access and services. Comprehensive state, regional, and town land use plans address multiple goals, including minimizing energy consumption and coordinating energy and non-energy regulations and goals.

3.3 Healthy Vermonters

Energy production and use in Vermont influences our ability to address challenges associated with chronic health conditions and exposure to pollution. The following priorities provide lenses for considering impacts related to human health caused by energy projects or policies.

Priority: **Encourage active lifestyles** and reduced energy use through compact development, and by providing safe opportunities for walking, biking, and using public transit.

Compact community design, supported by safe and efficient pedestrian, biking, and transit networks, helps reduce the amount of energy used for transportation purposes, while enabling more people to travel using physically active means. Healthy lifestyles reduce obesity, diabetes, and cardiovascular disease. Measures such as education, enforcement, and infrastructure strategies (e.g., Complete Streets and Safe Routes to Schools) help reduce traffic-related injuries and deaths.

Priority: **Improve outdoor air quality** by reducing emissions from transportation, home and business heating and energy usage, and energy production.

Using cleaner energy sources (e.g., solar and wind), improving energy efficiency, using cleaner fuels, shifting to cleaner transportation technologies (e.g., electric/hybrid vehicles), and changing behaviors (e.g., reduced travel, transit/biking/pedestrian travel) will ease air pollution and improve overall air quality. Reducing energy-related air pollution can result in improved respiratory and cardiovascular health, and reduced risks of Type 2 diabetes and cancer.

Priority: **Improve the health of indoor environments** and reduce energy bills through improved building weatherization and the use of advanced heating and ventilation technologies.

Improvements to home energy efficiency and heating systems can reduce energy usage, leading to cost savings, improved indoor air quality, and greater indoor comfort, while yielding better respiratory, psychological, and overall health. Using advanced wood-burning stoves and boilers improves home-heating efficiency, and reduces the detrimental impacts of wood burning on indoor and outdoor air quality. Replacing old heating units with clean, advanced energy technologies, especially in areas of at-risk populations, reduces risk to vulnerable individuals.

Priority: **Reduce negative health impacts** expected to occur as a result of climate change.

Climate change, which is affected by GHG emissions from energy production and usage, has been linked with health impacts related to heat illness, extreme weather events, degraded air and water quality, and vector-borne disease. A warming climate will likely increase demands for energy to cool homes, requiring thoughtful strategies to improve the efficiency of cooling systems and reduce the need for cooling with appropriate building, landscape, and community design.

Priority: **Assess the health impacts of our energy system** in order to avoid or mitigate potential negative impacts, especially for the most vulnerable population groups such as the elderly, low-income households, and those with chronic or pre-existing medical conditions.

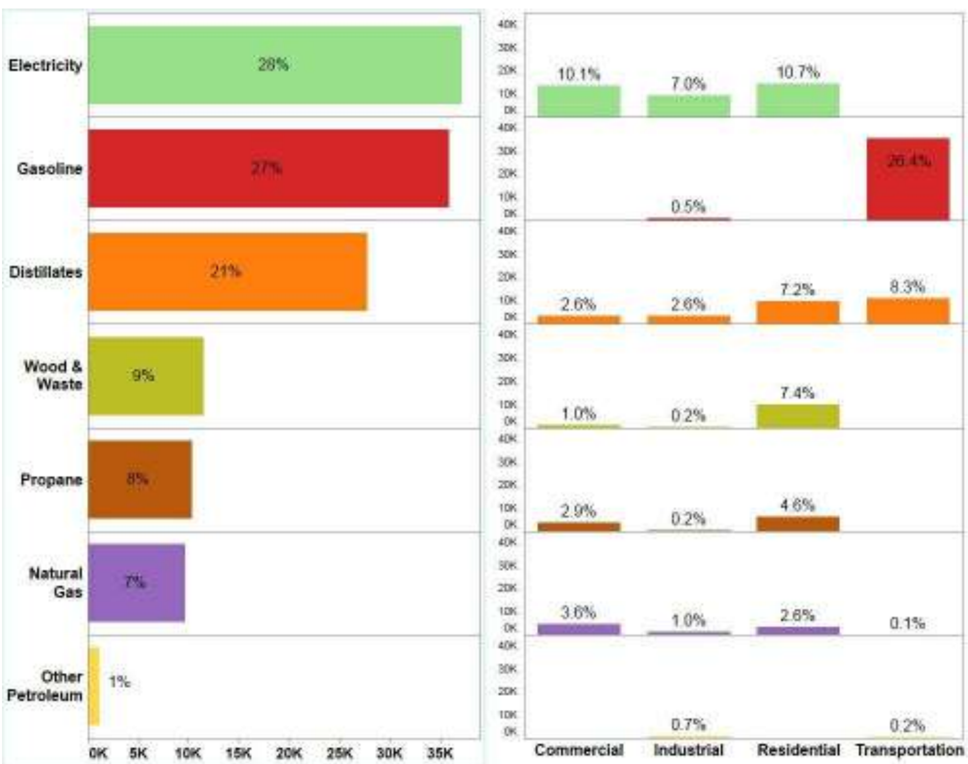
Human health depends on the continuity of energy services — particularly space heating and cooling, food refrigeration, and emergency services. At a minimum, we need to ensure that the most vulnerable populations are not further disadvantaged by the impacts of energy developments or strategies.

4 Overview of Supply and Demand: The Total Energy Perspective

4.1 Total Energy Consumption Today

This chapter presents an overview of Vermont's historical patterns of energy use up to the present, and considers how those consumption patterns will change as the state increases its reliance on renewable sources of energy. As shown in Exhibit 4-1, fossil fuels currently play a dominant role in meeting Vermonters' demand for energy services, with gasoline and distillates (namely diesel and heating oil) alone supplying around half of all of Vermont's primary energy consumption.

Exhibit 4-1. Composition of Vermont Consumption of Primary Energy, 2013 (Billions of Btu)



Sources: U.S. Energy Information Administration, State Energy Data System; Vermont Department of Public Service

*Notes: **Primary energy consumption** is a measure of energy consumption that includes the source energy required to produce the electricity consumed by end-users. This is a more inclusive measure of energy consumption than **site energy consumption**, which does not count the energy lost in conversion of source energy into electrical power. The distinction between source and site electrical energy consumption definitions is further detailed in section 4.1.1. Gasoline totals shown here include ethanol.*

At present, renewable energy makes up less than 20% of Vermont's total consumption of primary energy. The majority of Vermont's renewable energy consumption — around 65% — comes from an electric power supply that includes large amounts of hydropower (22% of source electric energy) as well as a significant amount of generation from biomass and wind resources (respectively, around 20% and 4% of total source electric energy). As shown in Exhibit 4-3, when measured on a source basis, Vermont's electric power supply is currently around 50% renewable (see below for definitions of *source* and *site* electric energy).[15] The remaining 35% of renewable energy consumption in Vermont is composed mostly of residential use of wood for home heating, and ethanol blended into gasoline stocks.

4.1.1 Site Energy vs. Primary Energy

When discussing Vermont's total energy consumption, it is important to understand how the physical quantities of the various fuels consumed in Vermont are converted into common units that can be meaningfully compared and summed to an overall total. This conversion is done using the heat content of a fuel, measured in British Thermal Units (Btu). For electricity, heat content, or Btu, can be measured on a *site* basis, which captures only the Btu of the kilowatts delivered to end users; or on a *source* basis, which captures the additional Btu of the fuels used to generate those kilowatts but which is lost as waste heat in the conversion to electricity. In this chapter, when the terms *total end-use energy consumption* or *total site energy consumption* are used, this indicates that the electricity component of the total was measured on a site basis. When the term *total primary energy consumption* is used, this indicates that the electricity component of the total was measured on a source basis.

Further, in calculating source energy totals for electric power, we assume that the heat content (Btu) of the source energy for non-combustion based renewable generators (solar, wind, hydro, and methane) is equivalent to the heat content of the kilowatts delivered to end users by those generators (where one kilowatt-hour is equivalent to 3,412 British thermal units). In other words, non-combustion-based generation is assumed to have zero waste energy. This differs from the practice followed by the U.S. Energy Information Administration (EIA), which assigns the kilowatts delivered by renewable generators a fossil-equivalent source heat content (where one kilowatt-hour is generally equivalent to between 5,000 to 10,000 British thermal units). All representations of total primary energy consumption in this chapter are calculated by the first of these two methods.

The table below provides the heat contents of the different generation fuels in Vermont's power supply mix that informed these calculations. Each entry represents the number of source Btu required to generate one megawatt-hour of electricity. With Vermont's current power supply mix, it requires an average of around 6.16 million Btu of source energy for each megawatt-hour supplied. Because there are

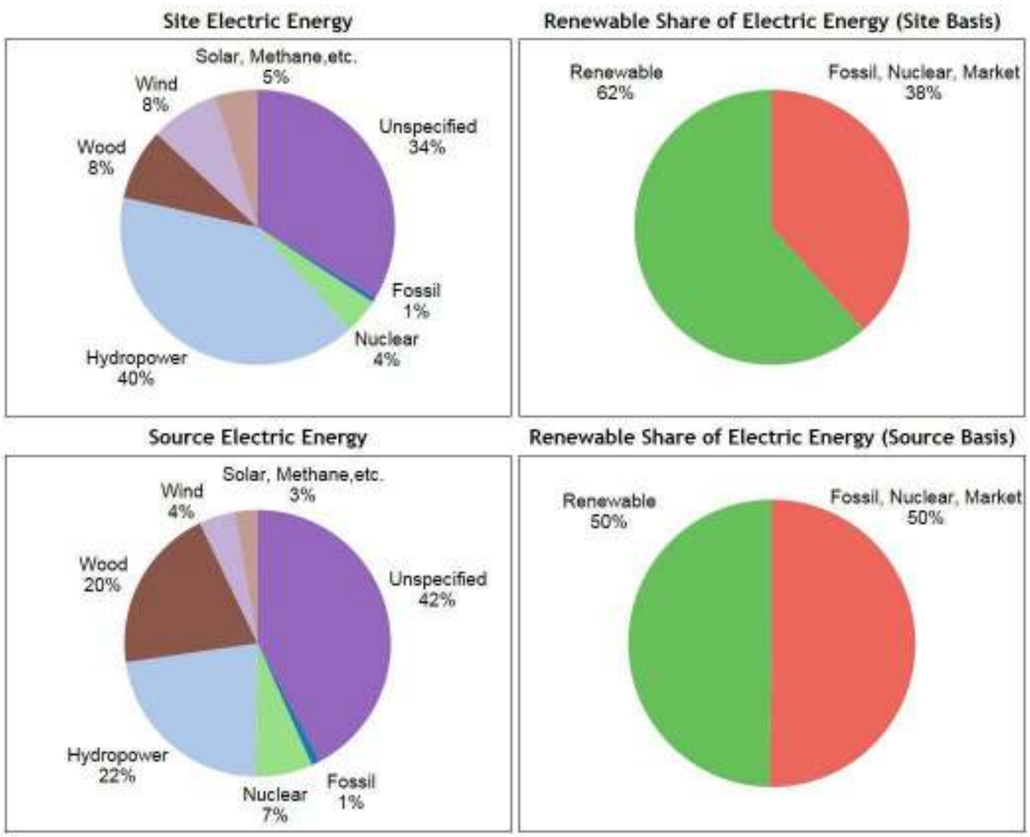
[15] This calculation ignores electric utility holdings of Renewable Energy Certificates (RECs). Taking REC holdings into account, Vermont's electricity mix is currently around 40% renewable, measured on a site basis. See Chapter 11 for a fuller discussion of utility holding of RECs.

3.4 million Btu in a megawatt-hour, this means that the overall efficiency of the generation fleet that serves Vermont load is about 55%, and accordingly that 45% of all source electrical energy is lost as waste heat.

Exhibit 4-2. Heat Rates and Conversion Efficiencies of Generation Fuels Used to Supply Vermont Electricity Load (Millions of Btu per MWh)

	Natural Gas	Distillates	Nuclear	Wood	Wind, Solar, Hydro, Methane
Heat Rate	7.9	10.7	10.4	15.0	3.4
Conversion Losses	57%	68%	67%	79%	0%

Exhibit 4-3. Generation Fuel Mix of Vermont's Electric Power Supply, 2014 (before REC sales or purchases)



Source: Vermont Department of Public Service.

Notes: *Fuel shares in Exhibit 4-3 are calculated before adjustments made to account for utility holdings of Renewable Energy Certificates. The "Unspecified" category represents power purchased either directly from the market or through a market intermediary. The generation fuels for these power purchases are not generally known by the utility. "Unspecified" power purchases are assigned a heat content equivalent to that of natural gas generation, the fuel that is currently most likely to be used to generate the electric energy acquired by utilities from the Independent System Operator of New England (ISO-NE) energy market.*

4.1.2 Productive Energy vs. Wasted Energy

The overall picture of energy consumption presented in Exhibit 4-1 shows the total amount of primary energy required to meet current levels of end-user demand for all of the energy services needed by Vermont households, businesses, and other institutions. The loss of source energy that occurs in the conversion of combustible and nuclear fuel into electrical power means that the total amount of energy that makes it to the end user — known as *delivered energy* — is less than the total amount of primary energy consumed by the state. However, not all of the energy delivered to end users will be converted to productive energy services.

Most end-use technologies that use combustible fuels — fossil fuel as well as liquid or solid biofuels[16] — convert only a fraction of the total energy used by the equipment into useful energy services received by individuals, such as heat and cooling for a building or propulsion of a vehicle. For example, a typical fossil fuel-burning furnace or boiler converts only 85% to 90% of the fuel it burns into useful building heat. A typical gasoline-burning internal combustion engine converts only 20% to 30% of the energy it consumes into motive force. Given Vermont's current heavy reliance on combustion-based technologies, the aggregate amount of energy lost to conversion of delivered energy into useful energy services is substantial.

The exact quantity of site energy wasted by Vermonters is not known with certainty. For the nation as a whole, it has been estimated that average sectoral end-use efficiency is only 65% in residential and commercial buildings, 21% in transportation, and 80% in industry.[17] In Vermont, less than half of the site energy delivered to Vermonters provides any useful energy service. Between the loss of energy in conversion of source fuels to electricity and the end-use waste from conversion of site energy to productive energy service, it is likely that more than 60% of all primary energy consumed by Vermonters is lost as waste.

4.1.3 Sources of Greenhouse Gases

Worldwide, climate change poses serious risks to economies, public health, and the environment. In Vermont, we are already experiencing the impacts of a changing climate: these include increased incidence of extreme weather events and flooding, changes in seasonal patterns, and the migration of new pests into forests and lakes. While the purpose of this CEP is not to present a detailed evaluation of the impact of climate change on Vermont, the state's commitment to reduce emissions of greenhouse

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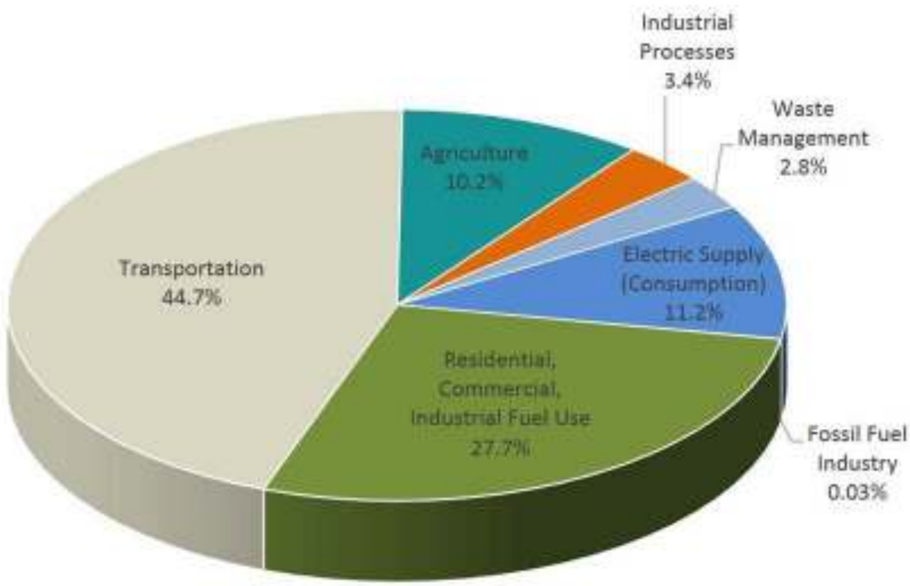
[16] Unless otherwise specified, wherever the term *biofuels* is used in this chapter, the definition includes both woody biomass (cordwood, pellets, and chips) and liquid forms (ethanol and biodiesel).

[17] Lawrence Livermore National Laboratory. See: flowcharts.llnl.gov/content/assets/images/charts/Energy/Energy_2014_United-States.png

gases (GHGs) within its borders is one of the primary rationales for developing a comprehensive energy plan that accelerates progress towards a clean energy future.

According to the state's annually published emissions inventory, in 2012, transportation, space heating, and electricity generation accounted for more than 80% of Vermont's annual GHG emissions. As shown in Exhibit 4-4, transportation accounts for 45% of GHG emissions, and is the state's largest contributing sector. Residential, commercial, and industrial fuel use together account for nearly 30% of emissions.

Exhibit 4-4. Vermont GHG Emissions by Source, 2012



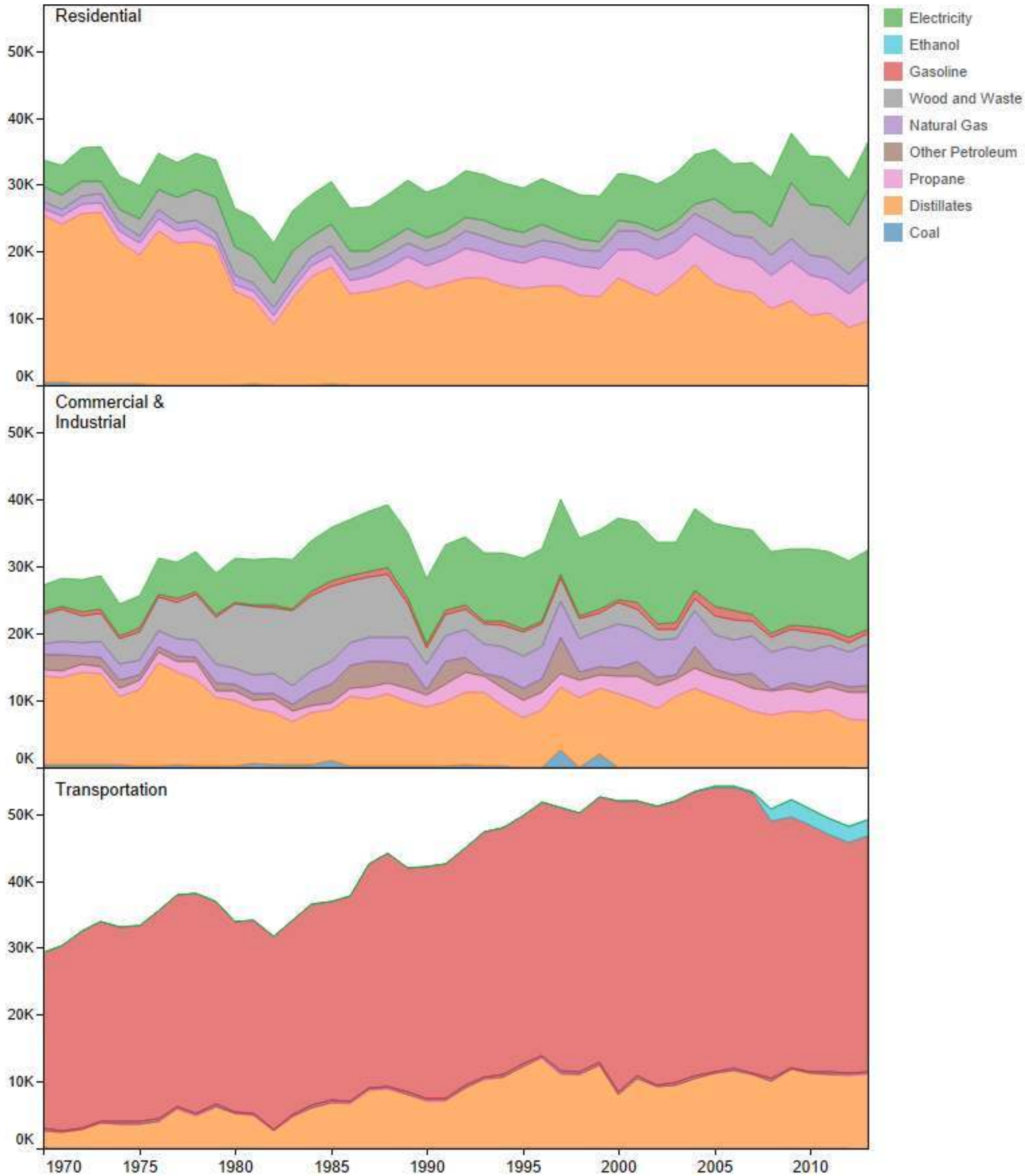
Source: Vermont Agency of Natural Resources

4.2 Energy Consumption Past to Present

Over the last four and half decades, overall demand for energy in Vermont has grown at a relatively modest pace. As shown in Exhibit 4-5, the majority of this growth has been driven by transportation uses of gasoline, business uses of electricity and natural gas, and residential uses of propane, wood, and electricity. Consumption of distillates has remained relatively flat over the last 40 years.[18] This is due to a steady decline in residential use, which has been only partially offset by an increasing use of diesel for transportation purposes.

[18] *Distillates* includes both fuel oil used for heating (currently accounting for around 60% of total distillate end use) and diesel used mostly for heavy-duty transportation (currently accounting for around 35% distillate end use).

Exhibit 2-5. Energy Consumption of End-Use Sectors, 1970-2013 (Billions of Btu)



Source: U.S. Energy Information Administration, State Energy Data System

Since 1970, total end-use energy consumption has increased at an average rate of around half a percent per year.[19] Over the same period, Vermont's population has grown at an average rate of around 0.8% per year. This means that Vermont consumes about as much site energy per capita today as it did in 1970. Even so, by a number of measures, the Vermont economy is significantly larger now than it was 40 years ago. Gross State Product has increased at an average rate of around 3% per year since the late 1970s, in real (inflation-adjusted) terms. Similarly, since 1975, the number of employed has grown by around 2% per year on average.

In more recent years, since around 2000, Vermont's overall demand for energy has moderated somewhat, even as the population and economy continued to grow (albeit more slowly than in the decades before 2000). Total energy end use is now 5% lower than it was 15 years ago, and per-capita site energy consumption now appears to be on a slight downward trend, having decreased by around a half a percent per year on average since 2000. This shift is mainly attributable to declining consumption of gasoline, electricity, and distillates, the three largest components of Vermont's total primary energy consumption.

Most of the decrease in gasoline consumption since 2000 is easily explained by a 10% decrease in vehicle miles traveled.[20] The decline in electricity end-use is attributable in large part to the efficiency programs run by Vermont's electric energy efficiency utilities, which are estimated to have reduced consumption by an average of about 2% each year over the last 15 years. Fuel oil heating equipment efficiencies have also improved over the last 20 years.

During the last decade, Vermont has also made progress in reducing GHG emissions. As shown in Exhibit 4-6, 2012 levels were approximately 14% lower than the 2004 emissions peak. However, Vermont fell short of its 2012 goal of reducing GHG emissions to 25% below 1990 levels; DPS recognizes that further steep reductions in emissions would be required to meet the statutory 2028 goal (50% below 1990 levels).[21]

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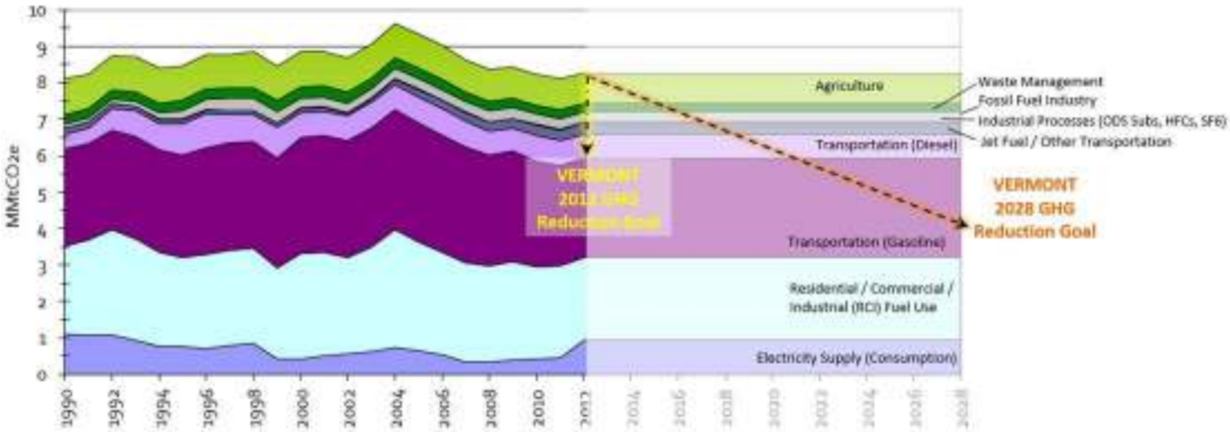
[19] All average annual growth rates identified in this chapter were computed as compound annual growth rates.

[20] Increasing average vehicle fuel economy and an aging population (with a lower than average demand for transportation energy) both also likely played a role. It is also possible that some amount of the decrease was induced by the generally escalating gasoline price environment over this time (see Exhibit 4-11).

[21] Vermont Department of Environmental Conservation, *Vermont Greenhouse Gas Emissions Inventory Update 1990-2012*, anr.vermont.gov/sites/anr/files/specialtopics/climate/documents/emissions/Vermont%20GHG%20Emissions%20Inventory%20Update%201990-2012_June%20-2015.pdf

Exhibit 4-6. GHG Emissions by Source, 1990-2028 (Millions of Metric Tons)



Source: Vermont Agency of Natural Resources

4.3 Goals for 2025 and Beyond

In 2014-2015, at the request of the Legislature, the DPS conducted the Total Energy Study (TES), an extensive modeling exercise that analyzed the viability of a variety of technology and policy "pathways" that could increase the share of renewable energy consumed in Vermont's to 90% of all primary energy used by 2050. The Total Energy Study yielded many insights about the scale, immediacy, and direction of the near-term changes in energy consumption patterns that will be necessary for the success of such a long-term transition. That analysis has informed this CEP's adoption of a set of interim goals set for 2025 to serve as guideposts along the way to 2050.

Specifically, these 2025 goals are:

1. **Reducing per-capita primary energy consumption by 15**%. The work done for the Total Energy Study revealed that total primary energy consumption will have to decrease by one third or more by 2050 in order to bring the 90% renewable goal into reach. Amplifying the recent trend toward lower per-capita site energy consumption will be critical to the achievement of Vermont's renewable energy goals. Importantly, a reduction in consumption on this scale does not imply a regime of energy austerity or any restriction on growth in manufacturing output. It is possible to provide an increased level of energy service, compared with Vermont today, with significantly less waste.

2. **Increasing renewable energy consumption to 25% of total primary energy consumption**, as established by 10 V.S.A. § 580(a). The modeling scenarios composed for the Total Energy Study showed that Vermont will need to look increasingly to electricity and biofuels (both liquid and solid) to meet its 90% by 2050 goal. DPS has concluded that achieving an interim 25% by 2025

goal could require cumulative increases in electricity end use of 10% to 15%, and cumulative increases in biofuel end use by as much as 20%, over the next 10 years.

There are a variety of ways in which changes in future sector-specific energy consumption patterns could combine to meet these 2025 benchmarks. DPS has developed an illustrative scenario, detailed further in Section 4.4, in which renewable energy consumption in building and transportation sectors follow unique trajectories. In this scenario, achieving an overall goal of 25% renewables by 2025 depends on:

1. **Increasing the share of renewable energy used in buildings to 30% of all primary building energy consumption, up from around 20% today.**

   Energy use in non-industrial buildings (both residences and commercial business places) currently makes up over 45% of total end-use consumption, a share that has been generally stable over the last 40 years. Heat energy (space and water heating combined) currently represents around 70% of overall building site energy requirements. About three quarters of this demand for heat energy is met with fossil fuels, primarily distillates — but increasingly over the past two decades also with propane and natural gas, which currently supply 25% and 15% of all non-industrial building heat respectively. Wood heat supplies around a quarter of non-industrial building site heat energy, mainly to households, up from only 10% in the 1990s. Electricity currently supplies very little of building site heat energy.

   Increasing adoption of heat pumps and wood heating technology has the potential to displace a significant amount of the fossil fuels that Vermonters rely on for space and water heating.[22]

2. **Increasing the share of renewable energy used for transportation to 10% of all transportation primary energy consumption, up from around 6% today**.

   Currently, transportation uses of energy make up almost 45% of total energy end uses — a share that has risen steadily since the 1970s, when it stood at roughly 30%. Gasoline provides the overwhelming majority of end-use transportation energy — and has for the last 40 years, though the share provided by diesel has gradually increased, from around 10% four decades ago to more than 20% in 2013. Since the mid-2000s, ethanol blends have reduced the amount of fossil fuel motor gasoline consumption by 5% to 7% annually.

[22] In the scenario presented in section 4.4, renewable energy use for industrial purposes follows a similar trajectory as the non-industrial buildings sector, reaching 30 % renewable by 2025. This is achieved mostly as a consequence of normal growth in non-heating electric consumption, which is supplied by increasingly renewable source energy. This path is distinct from the commercial and residential sectors, which meet their 30% benchmark targets in part by growing their electric heat loads. In addition, there is a moderate amount of displacement of industrial fossil fuels with biofuels. But because of the highly variable nature of industrial energy use and the large amount of uncertainty regarding the substitutability of various process fuels, hitting the overall interim goals in DPS's illustrative scenario does not depend critically on changes in industrial energy end-use patterns.

Higher concentrations of liquid biofuels in diesel stocks have the potential to displace a significant amount of the petroleum that Vermonters rely on for heavier duty transportation. Increasing adoption of electric vehicles has the potential to displace a significant amount of the gasoline Vermonters rely on to fuel their light-duty transportation.

In achieving these 2025 benchmarks, the electricity consumption of each end-use sector is sourced increasingly from renewable generation. Under the Renewable Energy Standard (RES) enacted by Act 56, electric utilities are required by 2017 to supply 55% of their retail electricity sales from renewable resources. By 2032, Act 56 requires that 75% of retail electricity sales be supplied by renewable resources. These requirements imply an average annual increase in the share of renewable electricity of more than 1% per year for the 15 years following 2017.

By the year 2025, Vermont's electric power supply is expected to be around 67% renewable. And as the renewable share of Vermont's electric power supply grows to meet the requirements of Act 56, the contribution of electricity consumption to the achievement of each sector's 2025 benchmark goals also grows.

Section 4.4.2 of this chapter looks more closely at the individual sector pathways described above, and the role that electrification plays in making them more achievable.

4.3.1 Revisiting GHG Targets

Vermont has long been among the U.S. states and subnational jurisdictions setting the most aggressive goals for reducing the emissions of carbon dioxide and other pollutants that disrupt earth's climate.

In 2001, before Vermont or any of the other New England states had developed a climate plan, the New England Governors and Eastern Canadian premiers jointly embraced a regional goal to reduce the total emissions from the participating states and provinces to 1990 emissions levels by 2010; 10% below 1990 levels by 2020; and 75% to 85% below 2001 levels by 2050.

In 2006, Vermont's Legislature set a long-term goal of reducing the state's own GHG emissions by 75% below 1990 levels by 2050. Interim targets were also set for the years 2012 and 2028. In 1990, Vermont emitted just over eight million metric tons of GHGs.

Since then, better information both about the current status of emissions and the potential effectiveness of different energy solutions has created a better understanding of the levels of emission reductions we could achieve in the near and long terms. The Total Energy Study has shown that the state's 2028 goal will be extremely difficult to reach — but the 2050 goal is achievable if Vermont keeps pursuing policies and investments that support a rapid transition to clean, efficient, renewable energy.

Vermont's leaders are continuing to embrace bold, long-term goals for reducing GHG emissions, motivated by the seriousness of the climate crisis and the economic benefits that will come to those communities, states, and regions that make earlier transitions to low-carbon economies. These goals are well-aligned with the energy goals established in both the 2011 and this 2015 CEP.

In spring 2015, Vermont joined the first group of signatories, along with jurisdictions from seven countries and three continents, to sign California's bold "Under Two Memorandum of Understanding." The parties to the MOU jointly agreed to pursuing emission reductions consistent with a trajectory of 80% to 95% below 1990 levels by 2050, and/or achieving a per-capita annual emission goal of less than two metric tons by the same year. By signing the MOU, Vermont strengthened its 2050 goal beyond its initial statutory goals established nearly a decade ago.

In summer 2015, the Northeastern Governors and Eastern Canadian Premiers (NEGECP) passed a new climate resolution, in which they jointly reaffirmed the original 2050 goal, set back in 2001, and committed to making bigger reductions sooner. The resolution established a regional 2030 "progress marker range" of 35% to 45% below 1990 levels by 2030. This interim goal is closely aligned with the trajectory necessary for meeting the longer-term goals in the California MOU. In short, the multiple goals and agreements all line up on a very similar pathway to a sustainable, low-carbon future.

Informed by this progress on GHG reduction goals, this CEP establishes two goals for reduction in GHG emissions from Vermont's energy use, which are consistent with the renewable energy and energy use goals also established here:

- 40% reduction below 1990 levels by 2030;
- 80% to 95% reduction below 1990 levels by 2050.

GHG Accounting and Sustainability

Vermont's comprehensive energy planning efforts will also help the state gain a more complete understanding of the true carbon footprint of its energy choices. To accomplish this, the state intends to explore tools that will facilitate a more comprehensive accounting of life-cycle energy/carbon intensity, along with the energy and emissions associated with the direct use of a particular fuel or technology. The ideal methodology would enable concurrent comparison of all attributes of our energy choices — including GHG emissions, other pollutant emissions, land use changes, economic effects, etc. — and would be universally accepted and applied.

Current analysis methods (including those developed by the EPA, the State of California, and the European Union) focus on accounting for direct and indirect GHG emissions from particular fuel/feedstock pathways. These methodologies are not consistent with each other, particularly in the way they account for indirect emissions. There is also ongoing academic research in this field. Particularly promising are the efforts of the National Renewable Energy Laboratory, which is currently attempting to harmonize the wide variety methodologies used to produce life-cycle assessments of different electricity generation technologies. The state will continue to monitor developments in this area, both independently and in conjunction with other states in the region, with the goal of adopting a methodology based on the latest scientific knowledge that can be used to evaluate a wide array of energy sources and rapidly evolving technologies. This effort will be consistent with the state's definition of least-cost integrated resource planning, as set forth in 30 V.S.A. §218(c).

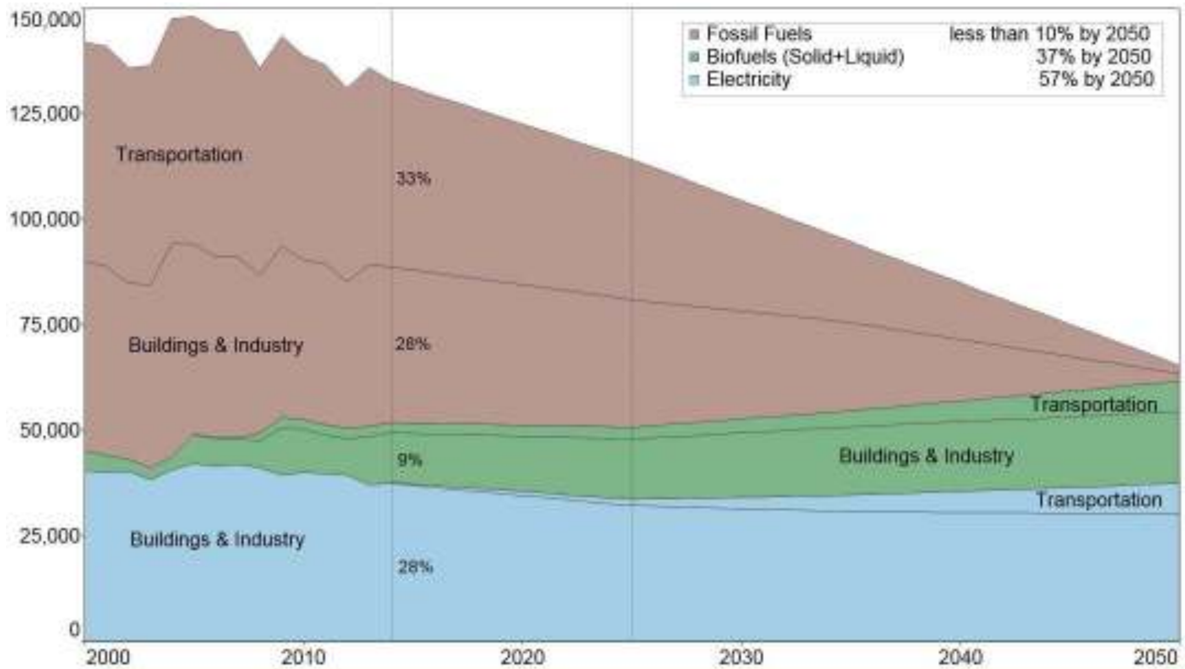
Future energy demands will likely begin to put more pressure on Vermont's forests and farmland as a source for energy wood and biofuels. As a result, careful consideration will need to be given to all the values of our forests, including ecosystem integrity, wildlife habitat, air and water quality, forest health, recreation, wood products, food crops, etc. Energy wood and biofuels can fill an important role as a local, renewable energy source. Done correctly, an improved energy wood and biofuels market can enhance the sustainable management of our forests and farmlands, and can help advance the underlying goals of those lands. With respect to carbon, it is important to keep in mind that the actual effect on the carbon cycle of increased wood use (sequestration vs. emissions) can vary substantially depending on specific type of biomass fuel, its growth rates, harvesting practices, transport distances, and the end uses of the fuel.

4.4 Getting to 25 Percent Renewable Energy by 2025

This section presents the modeling results from the Total Energy Study that inform DPS's recommended sector-specific 2025 benchmark targets, introduced above in section 4.3. Exhibits 4-7 and 4-8 depict an energy future in which the levels of end-use consumption of electricity and biofuels are each more than 70% greater in 2050 than they are today.[23] To reach this point would require average growth rates in usage of those fuels of more than 2% per year. The picture of Vermont's overall energy consumption that results from this trajectory is dramatically different from today. Electricity consumption in 2050 would make up more than 45% of total end use across all sectors, compared to only 20% today. Similarly, consumption of biofuels would make up more than one-third of total end use, compared to less than 15% today.

[23] Note however that Exhibit 4-7 is a depiction of primary energy consumption, and the dramatic increase in electricity end use will not be evident from this representation. See Exhibit 4-8 for graphic depictions of the increase in electricity end use without increasing electricity primary energy demand.

Exhibit 4-7. Sector Uses of Primary Energy, Projected to Meet 2050 Goals and 2025 Benchmark Targets (BBtu)

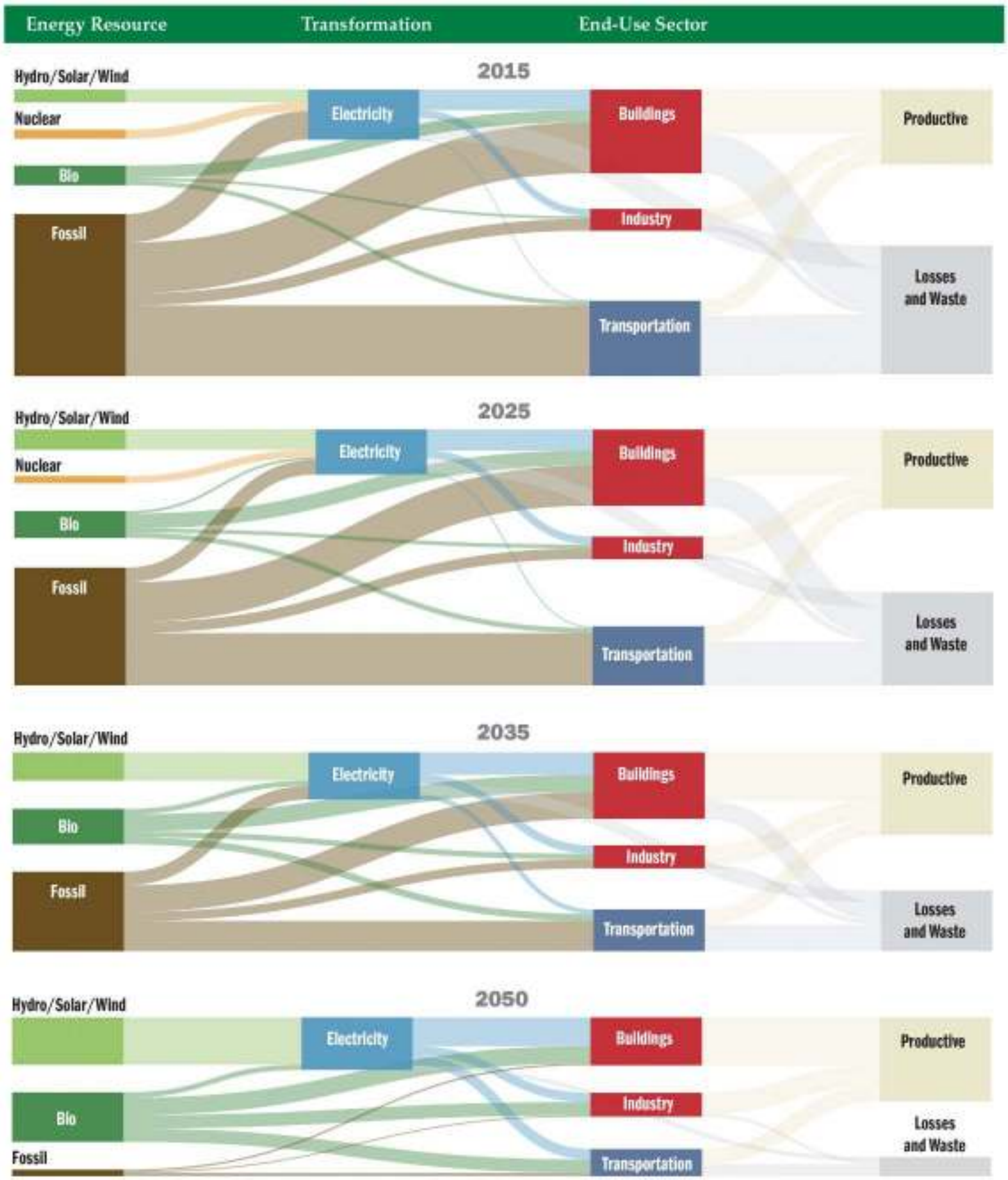


Sources: U.S. Energy Information Administration, State Energy Data System; Vermont Department of Public Service.

Notes: Projections are based on results of Total Energy Study. Vertical reference line at year 2013 marks end of historical data. Vertical reference line at year 2025 marks benchmark 25% renewable target.

Exhibit 4-8 shows Vermont's estimated total energy flows for 2015 and 2050. Each portion of the figure begins with primary energy on the left side, divided into four types: hydro/wind/solar (non-combustion-based renewable resources), bio (combustion-based renewables), nuclear electricity, and fossil fuels. The height of each band corresponds to the amount of energy from each source. Some of each resource then flows to be transformed into electricity, while some combustible resources are used directly in each end-use sector (buildings, industry, and transportation). Losses and waste from electric generation are totaled on the far right, along with waste and losses from each of the end-use sectors: buildings, industry, and transportation.

Exhibit 4-8. Vermont Energy Flows in 2015, With an Illustrative Path Forward to 2025, 2035, and 2050



4.4.1 Ways of Reducing Energy Usage

In year 2025 of the illustrative scenario shown in Exhibits 4-7 and 4-8, Vermonters are consuming around 20 trillion Btu less primary energy than they consume today, a 15% reduction. The majority of this reduction — around 60% — is attributable to changes in non-industrial building energy consumption patterns. Most of the rest of the reduction is attributable to changes in transportation energy consumption patterns.[24] For both sectors, this reduction in primary energy consumption is the outcome of three distinct trends:

1. ***Continuing improvements in demand-side thermal and electric efficiency and conservation****, accounting for 20% of the reduction in primary energy consumption*.

   In the illustrative scenario, all the historical drivers of growth in energy consumption — population, building square footage, industrial output, etc. — are assumed to follow a normal increasing trend, consistent with past observation. However, simultaneous improvements in efficiency and conservation are significant enough to neutralize the increase in energy demand associated with this normal economic growth. The largest source of these energy savings is improvements made to the thermal efficiency of building shells, which reduces the need for building heat to be delivered by any means.

2. ***Fuel switching away from combustion technologies to more efficient electric-powered technologies****, accounting for 40% of the reduction in primary energy consumption*.

   The current generation of heat pump and electric vehicle technologies are capable of supplying the same level of energy service as their combustion-based counterparts, with a third or less of the site energy requirements. In the illustrative scenario, increasing adoption of substitute electric technologies is the most significant driver of the decrease in per-capita site energy consumption. A substantial amount of fuel switching to biofuels (from fossil fuels) is also taking place in this energy future; but because this does not entail any significant change in the efficiency of the technologies using those biofuels, no significant reduction in energy demand results from the adoption of biofuels.

3. ***Declining source energy requirements of electricity generation****, accounting for 40% of the reduction in primary energy consumption.*

   As more of the state's electric power supply is generated by renewable resources like solar, wind, and hydro, which do not produce the unusable waste heat associated with combustible generation fuels, the overall source energy required to power growing heat pump and electric

[24] Industrial energy consumption patterns are largely held constant in the illustrative scenario.

vehicle loads also declines. In the illustrative scenario, this decrease in electric source energy requirements is significant enough to result in a reduction in the total amount of primary electric energy consumed, even though the amount of electricity demanded by end users is growing. So, even as per-capita site energy consumption is driven down — on the order of 1% per year — by use of more efficient electric technologies and continued demand-side improvements, per-capita consumption of primary energy declines even faster, by almost 2% per year.[25]

Each of these features of the scenario illustrated in Exhibits 4-7 and 4-8 are explained in further detail below.

[25] Other inefficiencies inherent in electric power delivery, such as line losses, are also reduced as more electric source energy comes from renewable distributed generators and storage facilities sited closer to end-user load sites. However, these benefits were not examined in detail by the TES, and are not reflected in the reductions in primary energy consumption shown in Exhibits 4-7 and 4-8.

Implications of Act 56 on Future Electric-Source Energy Consumption Totals

In 2014, Vermont's consumption of site electric energy totaled around 19 billion Btu, amounting to roughly 15% of all site energy consumed by end users in that year. Around 60% of this electricity was generated by renewable resources, the majority of which were not combustion-based (See Exhibit 4-3). Given this mix of generation resources, it took about 33 billion Btu of source energy to supply the 19 billion Btu of site electricity consumed by end users, amounting to nearly 30% of total primary energy consumption. This means that the current fleet of generators serving Vermont 's retail load waste about as many units of energy as are delivered to end users for ultimate consumption.

Under the requirements of Act 56, the renewable share of site electric energy is expected to be 75% by 2032. Accordingly, only 20% to 25% of Vermont's load is expected to be served by combustion-based or nuclear generation. At the same time, growth in electricity consumption will likely be significant over this period, if consumers take advantage of the efficiencies of cold-climate heat pumps and passenger electric vehicles. In the scenario illustrated in Exhibits 4-7 and 4-8, electricity end use rises by more than 500 gigawatt-hours by 2025, an almost 10% increase over current retail sales levels. But with that much more renewable generation powering this load growth, total consumption of source electric energy will have actually declined from 2014 levels.

For every unit of electric energy delivered to consumers in 2032, only half a unit of additional energy will be lost to the combustion process. Thus, by 2032, even with significantly increased consumption of electricity, the total source energy used to supply that electricity might only be 32 or 33 billion Btu, around 15% lower than today.

Demand-Side Efficiency and Conservation

Thermal

In 2013, the average size of an annual residential heating load in Vermont was in the range of 80 to 100 million Btu, the same size as 35 years ago. Average commercial building heating loads are slightly larger, in the range of 100-120 million Btu per year.[26] A typical weatherization investment in either sector can reduce an individual building's annual heating load by 20% to 30%, all else being equal. In the illustrative scenario depicted in Exhibits 4-7 and 4-8, primary energy used in non-industrial buildings declines by more than 10 trillion Btu cumulatively by 2025. Around 20% of this reduction is attributable to improvements in commercial and residential building shells over the next 10 years.

[26] U.S. Energy Information Administration, State Energy Data System and Residential and Commercial Energy Consumption Surveys

Electric

In 2013, the average size of a residential building's electric load in Vermont was around 20 to 25 million Btu of electric site energy, around a third smaller than it was 20 years ago.[27] The average commercial building electric loads are significantly larger, around 130 to 135 million Btu per year, but have likewise declined over the last 20 years.[28] In the illustrative scenario, around 10% of the reduction in primary energy used by buildings is attributable to improvements in the demand-side efficiency of non-heating uses of electricity — lighting, appliances, and other miscellaneous plug loads. This magnitude of reduction is consistent with the level of past end-user electricity savings that have been achieved by the state's energy efficiency utilities.

Fuel Switching Efficiency

Electric Heating

With combustion-based space and water heating equipment, typically only 85% to 95% of the site energy delivered to buildings for heating purposes will be converted into actual, useful heat energy. The remaining 5% to 15% is lost as waste heat in the combustion processes of furnaces, boilers, and stoves. In contrast, the heat energy produced by an electric-powered air-source heat pump does not rely on a combustion process, and so does not generate waste heat. Instead, the heat delivered to buildings by an air-source heat pump is extracted from the ambient air, and the current technology is capable of delivering two or three times as much useful heat energy as it takes to power the equipment that performs this extraction.

As a result, a modern heat pump is capable of supplying the majority of a typical building's 80 to 120 million Btu seasonal heating load with only around 30 to 50 million Btu of site electric energy[29], leaving around 10 to 20 million Btu[30] of heat energy to be supplied with backup combustible fuels. While heat pumps of the current generation are likely to serve as the *sole* source of heat for only the most thermally efficient buildings, they have significant potential heat energy savings as a *main* heat source for buildings with even average-quality envelopes.

In the illustrative scenario, around 20% of the reduction in primary energy used in buildings is attributable to the replacement of fossil fuel-burning heating equipment, with electric-powered heat pumps becoming the primary space- and water-heating method. As illustrated in the energy flow diagram in Exhibit 4-8, one consequence of this scale of conversion to heat pumps is that by 2050, when more than 300,000 buildings could be using cold-climate heat pumps, the sector as a whole is receiving a

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[27] Equivalent to approximately 5,800 to 7,300 kWh per year.

[28] Equivalent to approximately 38,000 to 40,000 kWh per year.

[29] Equivalent to 8,800 to 14,700 kWh.

[30] Equivalent to approximately 75 to 150 gallons of distillate fuel oil.

greater amount of heat energy service than the amount of energy that is delivered to buildings in the form of fuel or electricity. This is very different from today, when around half of the energy delivered to buildings becomes useful energy service.

Electric Vehicles

The average gasoline-burning passenger vehicle uses around 75 to 100 million Btu of energy per year (500 to 650 gallons) to travel a distance of 10,000 to 12,000 miles. However, most of the fuel burned by a conventional vehicle's internal combustion engine does not produce any mechanical force. Around 70% to 80% of the energy content of the gasoline, diesel, and biofuels that are burned by conventional internal combustion vehicles is lost as waste heat that must be dissipated away from the engine. Even vehicles with the best fuel economies are only capable of converting around 20% to 30% of the fuel they burn into useful vehicle motion. In contrast, today's electric vehicle motors are capable of converting around 60% to 70% of the electricity they use into useful motion; only 30% to 40% of the electric energy is lost as waste heat.

Because of this superior efficiency, a modern electric passenger vehicle can drive the same annual distance as a gasoline-burning vehicle (10,000 to 12,000 miles), using only 11 to 20 million Btu of electric site energy (equivalent to between 3,300 and 6,000 kilowatt-hours per year). In the illustrative scenario, transportation primary energy declines dramatically, dropping by 7.5 trillion Btu by 2025. The vast majority of this reduction is attributable to the replacement of light-duty gasoline-burning vehicles with more efficient passenger electric vehicles that consume only a fraction of the site energy that Vermonters are accustomed to using to meet their transportation and mobility needs.

As illustrated in the energy flow diagram in Exhibit 4-8, one consequence of this scale of conversion to electric vehicles is that by 2050, when there could be as many as 600,000 electric vehicles on the road, the transportation sector as a whole will only be wasting around half of the site energy it consumes — much less than the approximately 70% or 80% wasted by today's predominately fossil fuel-burning fleet.

Renewable Generation Efficiency

With the present mix of generation resources that supply Vermont's electric power, around 45% of all kilowatts delivered to retail customers are generated without any of the upstream conversion losses associated with combustion-based generation[31].This means it currently takes around 43 to 49 million Btu of source energy to supply the 7,000 to 8,000 kilowatt-hours needed to serve a typical individual building's heat pump load through a heating season. In 2025, when more than 65% of delivered kilowatts are expected to be generated without conversion losses, the same heating load would require only around 35 to 40 million Btu of source electric energy — more than 18% less than what it takes today.

[31] Power generated by hydropower, solar, wind, farm methane, and landfill methane resources is equal to 55% of all power supplied by Vermont electric utilities.

In 2032, when Act 56 requires the electricity supply to be 75% renewable, it would require only 30 to 35 million Btu of electric source energy to serve a typical heat pump load — more than 30% less than what it takes today. Similarly, by 2032, the 30 to 40 million Btu of electric source energy it now takes to power a typical electric vehicle for a year will be as little as 10 to 20 million Btu. If Vermont's electricity were generated completely without any combustion-based resources, there would be no conversion losses at all, and it would take roughly the same amount of source energy to power a heat pump or electric vehicle as that heat pump or vehicle will use.

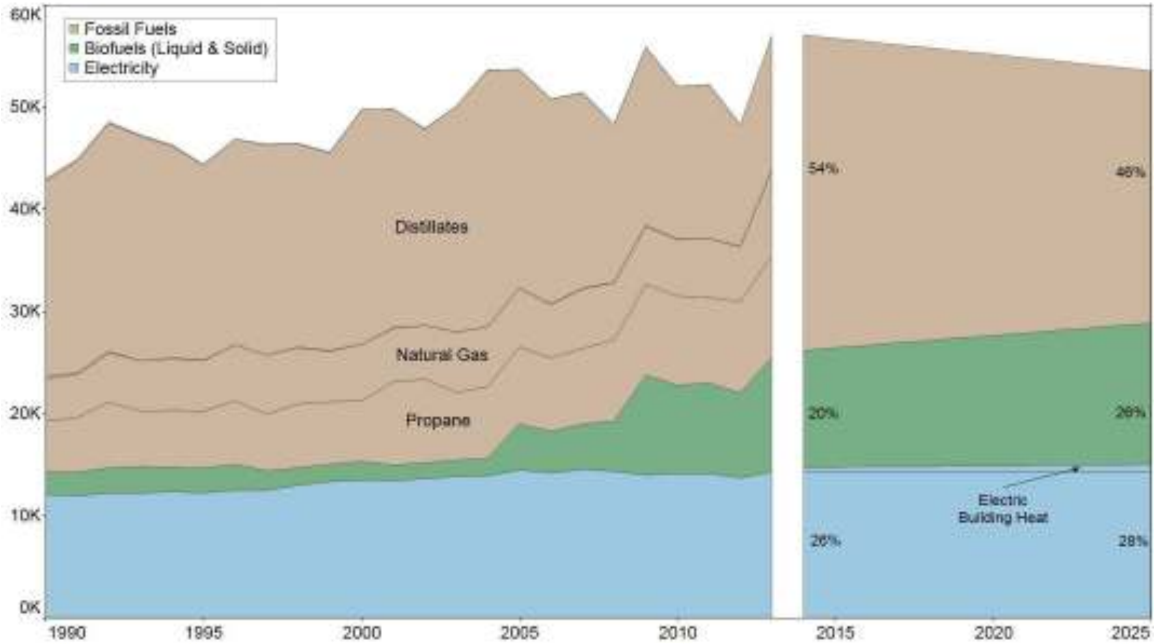
4.4.2 Sector Paths to 2025

4.4.2.1 Buildings

Exhibit 4-9 depicts the future changes in energy end uses in the buildings sector that correspond with the first 10 years of the projection period in the illustrative scenario shown in Exhibits 4-7 and 4-8. Over this time frame, the buildings sector is able to meet a 30% renewable energy benchmark target by increasing the electricity share of its demand for heat energy to around 3%, up from virtually zero today. This magnitude of increase in electricity consumption could mean around 35,000 to 40,000 heat pump installations cumulatively by 2025, serving between 10% and 15% of Vermont's total non-industrial building stock.

In parallel with these heat pump conversions, the buildings sector is also increasing the biofuel share of its demand for heat energy, from around 20% today to more than 25% by 2025. If the entire increase in biofuel end use shown in Exhibit 4-9 were to be met with woody biomass, it could mean more than 60,000 buildings using cordwood or pellets as their primary heating fuel by 2025, representing around 15% to 20% of the non-industrial building stock. If the increase in biofuel consumption were to be supplied completely with liquids, it could mean blends of fuel oil with home bio-content as high as 15% by 2025.

Exhibit 4-9. Building Energy End-Use Since 1990 With Projections Meeting 25% Renewable Goals (BBtu)



Sources: U.S. Energy Information Administration, State Energy Data System; Vermont Department of Public Service. Projections beginning in 2014 are based on results of Total Energy Study

Because of the superior efficiencies and lower inherent wastefulness of substitute heat pump technologies, the moderate increase in electricity consumption from new heat pump loads is accompanied by a much more pronounced decline in consumption of fossil fuels. In addition, thermal and electric efficiency improvements help to keep the overall demand for building site heat energy from growing along with the economy. In Exhibit 4-9, by 2025, thermal efficiency improvements have reduced the average building's heating load by around 10%. With a typical energy savings of 10 to 30 million Btu per building, this could require more than 10,000 building-shell improvements per year, an annual retrofit or replacement of as much as 5% of Vermont's entire non-industrial building stock. Similarly, continuing improvements in the electric efficiency of end uses like lighting and other plug loads will reduce average building non-heat electric consumption by around 5% cumulatively by 2025.

Illustrative Economics of Electric Heat Pumps, Efficiency, and Biomass

Consumer Economics

A typical Vermont family heating their home with a distillate-burning furnace or boiler will currently spend around $1,800 to $2,200 annually on purchases of fuel oil, to meet a winter heating load of around 100 million Btu.[32] Using cold-climate heat pumps as the primary source of heat energy, that same level of demand can be met with about $1,650 to $1,750 in annual fuel costs (around $350 to $550 of which might

[32] This calculation assumes 138 thousand Btu per gallon of fuel oil and a range in fuel oil prices of $2.50 to $3.00 per gallon (equating to a price range of $18 to $22 per million Btu).

be spent on backup fossil heat sources).[33] Advanced wood stoves and central pellet systems are capable of serving this heating load with $1,500 to $1,800 in annual fuel costs. Combining any of these renewable heat options with an investment in weatherization can further reduce annual heating fuel costs by $300 to $600.

While these fuel bill savings are compelling, potentially amounting to more than $1,000 per year on the high end, the upfront capital costs necessary to realize them are generally expensive enough to discourage most income groups from making such investments. Access to finance at reasonable terms will be critical for most building owners. In the case of cold-climate heat pumps or modern wood heat stoves, loans can generally be easily arranged with vendor financing packages. Central pellet heating systems and weatherization investments, however, can often cost more than $10,000. Taking a whole-building approach that couples heating system and electric appliance replacements with weatherization can amount to a $30,000 to $50,000 investment.

Recent innovations in financing that link bill payments, equity, and public sector incentives may provide critical tools to help building owners access the cost savings of these larger investments. The coordination of energy services and financing may lead to a business model similar to the energy service companies that currently link finance with energy service installations. Examples of a successful whole-building approach will be a key to ultimately providing a large number of building owners with the access to building improvements necessary to meet the state's long-term energy goals.

Macroeconomics

Fuel Oil Spending

Realizing the customer fuel-cost savings described above will necessarily reduce the sales of Vermont fuel oil distributors, which currently employ between 1,000 and 1,500 workers, paid an average wage of more than $45,000 a year.[34] These wages, plus other operating costs and retailer profits, represent only around 20% of the retail price of fuel oil paid by end-use customers. The vast majority of retail customer dollars spent on fuel oil, around 80%, goes to pay wholesale commodity costs to out-of-state suppliers and does not circulate as local income in Vermont.

Electricity Spending

In contrast, DPS estimates that only 40% to 50% of the Vermont retail customer's purchases of electricity goes to pay for power supplied by out-of-state generators. Around 10% to 15% goes to pay for power supplied by in-state generators that employ Vermont workers and own plant and equipment based in

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[33] This calculation assumes that cold-climate heat pumps will displace 75% to 80% of a residence's 100 million Btu of annual heating load using 8,000 to 9,000 killowatt-hours, with 145 to 180 gallons of fuel burned to cover the 15% to 20% of annual heating load not supplied by the heat pumps. Price of electricity is assumed to be 15 cents per kilowatt-hour.

[34] Federal Bureau of Labor Statistics; Vermont Department of Labor

Vermont. As more distributed-generation resources like solar and wind are built to replace power from more remote, less labor-intensive central power stations, the share of retail customer electricity spending flowing to Vermont-based labor and capital will likely increase. For example, the 2015 Vermont Clean Energy Industry Report identifies around 2,000 workers involved with the installation and operation of solar and wind generation facilities, with growth in solar-related jobs paralleling the roughly 20% increase in solar installations over the last year.[35]

Much of the remainder of the Vermont customer dollars spent on electricity, roughly 30% to 40%, goes to pay for local labor employed directly by utilities — more than 2,000 workers who are paid an average annual wage of between $80,000 and $90,000.[36] As monopoly providers with established scale economies, electric utilities will not likely need to significantly expand hiring in response to a future increase in electricity sales associated with electric heating and vehicle load growth. There are, however, new income-earning opportunities opening up for potential utility partners that are capable of supplying the labor and expertise needed to tackle the ongoing challenge of integrating distributed energy resources into utility grid management operations.

Biomass Spending

Even more than Vermont's electricity supply, cordwood is sourced almost entirely from in-state producers whose largest cost is the local labor they employ. This is not currently the case for wood pellets, which except for two in-state production plant are supplied to Vermont retail customers by producers in Quebec and in other parts of northern New England. Thus, as for retail purchases of fuel oil, the local employment supported by spending on wood pellets consists mostly of retail and distribution operations. Growth in pellet demand could lead to more local production.

Currently around 2,500 to 3,500 workers are employed in the forestry and wood-product manufacturing industries.[37] Historically, less than 2% of Vermont workers have found employment in this industry space, which for most workers is only a seasonal source of income. A future in which as much as one third of building site heating demand is met with biomass sourced from Vermont forests would present far greater opportunities for employment, innovation, and profit in the harvesting, processing, and delivery of wood energy products to Vermont homes and businesses.

Efficiency Investment

Investments in thermal efficiency improvements also provide income-earning opportunities for workers and entrepreneurs in Vermont's growing building-performance industry. Between 30% and 50% of the cost of a typical weatherization project goes to pay wages of locally hired construction labor. At present

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[35] BW Research Department for VT Dept. of Public Service, *Vermont Clean Energy 2015 Industry Report*, publicservice.vermont.gov/sites/psd/files/Announcements/VCEIR 2015 Final.pdf

[36] Federal Bureau of Labor Statistics; Vermont Department of Labor

[37] Federal Bureau of Labor Statistics: Vermont Department of Labor

there are fewer than 15,000 workers employed in the Vermont construction industry, down from a mid-2000s peak of more than 17,000. According to data collected for the Vermont Clean Energy Industry Report, weatherization activities over this time helped to employ several hundred construction industry workers that would have otherwise lost their jobs as the housing investment boom deflated and the construction share of the labor force returned to its historical norm of around 7%.

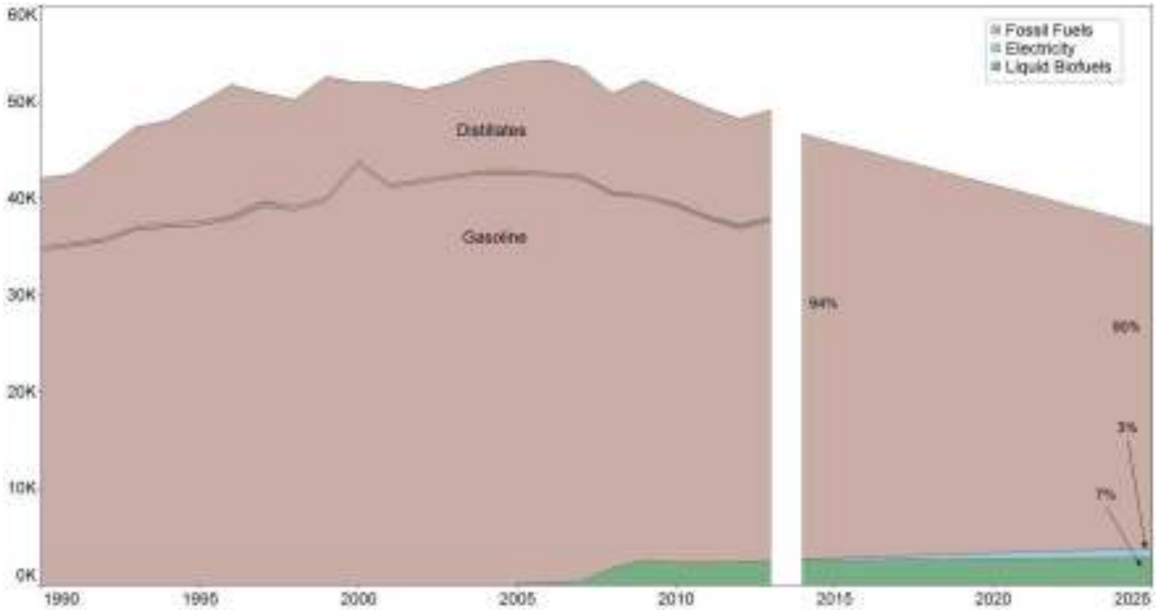
Today around 1,000 homes are built in Vermont each year. A future in which each year potentially more than 10,000 homes are weatherized — and as many more are outfitted with heat pumps or wood heating systems — will present significant opportunities for employment, innovation, and profit in the construction and building-performance industries.

4.4.2.2 Transportation

Exhibit 4-10 depicts the future changes in transportation energy end use that correspond with the first 10 years of the projection period in the scenario illustrated in Exhibits 4-7 and 4-8. Over this time frame, the transportation sector is able to meet a 10% renewable energy target by increasing the amount of electric energy used in light-duty vehicles to around 3% of all transportation energy end use, from virtually zero today. This is accomplished alongside only slight increases in the biofuel content of gasoline and diesel — which rises to around an 8% concentration, not a significantly greater amount of ethanol than has been consumed in recent years.

An increase in electric vehicle use on the scale depicted in Exhibit 4-10 would mean the replacement of around 115,000 to 120,000 gasoline-burning passenger vehicles — between 15% and 20% of the total stock of light-duty vehicles. While future site energy consumption in the buildings sector is held largely flat by consumer fuel switching to more efficient heat pumps, the increased use of electric vehicles by the transportation sector has the effect of significantly reducing its total end-use consumption, by more than 15% cumulatively by 2025.

Exhibit 4-10. Transportation Energy End-Use Since 1990 With Projections Meeting 25% Renewable Goals (BBtu)



Sources: Federal Energy Information Administration, Vermont Department of Public Service. Projections beginning in 2014 are based on results of Total Energy Study

Illustrative Electric Vehicle Economics

<u>Consumer Economics</u>

The typical driver of a conventional gasoline-burning passenger vehicle spends about $700 to $1,800 per year on fuel to travel an annual distance of 10,000 to 12,000 miles.[38] The same number of miles can be driven in an electric-powered passenger vehicle at an annual fuel cost of almost half that amount — around $500 to $900.[39] But while converting to an electric vehicle can potentially save a typical customer almost $1,000 in annual fuel costs, the retail prices of electric vehicles are significantly higher than the prices for internal combustion cars —as much as $10,000 higher before federal tax credits. Assuming that an electric vehicle can be financed with the same terms as a conventional auto loan, the fuel cost savings realized at current gasoline prices are not generally large enough to cover the higher loan repayments that accompany an unsubsidized electric vehicle purchase. Federal tax credits help to bring electric vehicles closer to mass market affordability, and are now generally built in to electric vehicle leases.

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[38] Calculation assumes a range in vehicle fuel efficiency of 20 to 30 miles per gallon, and a range in the price of gasoline from $2.10 to $3.00 per gallon.

[39] Calculation assumes a range in electric vehicle efficiency of two to three miles per kilowatt-hour and a retail price of electricity of 15 cents per kilowatt-hour.

Macroeconomics

Vermonters currently spend about $1 billion annually on retail gasoline purchases.[40] Around 70% of this total goes to pay for the wholesale commodity supplied by out-of-state producers and marketers, and does not circulate as income in the Vermont economy. A little less than 15% of gasoline spending goes to cover the costs and profits of retailing operations based in Vermont; this includes a wage bill of around $68 million, paid out to approximately 3,000 to 4,000 gasoline station workers at an average annual wage of less than $25,000. About 6% of retail customer gas spending goes to pay the federal gas tax, and around 10% is collected into the state transportation fund.

Replacing conventional vehicles with electric vehicles on the scale depicted in Exhibit 4-10 will thus reduce the expenditures for transportation fuel going out of state. However, under current transportation funding arrangements, this will also pose a challenge to the state's ability to pay for transportation infrastructure maintenance and improvements. Over time, the shift away from gasoline consumption would also likely lead to reductions in employment at retail gasoline stations.

4.5 Policy Tools to Drive Change

There are four general types of policies that work together to drive change: market-based policies, information and access policies, strategic investment, and codes and standards.

Market-based policies (also called price-based policies) establish a new market or shape the prices in an existing market in order to harness market forces to achieve a policy goal. Examples include cap and trade systems (which create a new market for emission allowances), renewable portfolio standards (which create a new market for renewable energy credits), and carbon taxes (which shape existing energy markets by changing the relative prices of fuels). Market-based policies are intended to send a price signal to end-use consumers that encourages consumption of a renewable or efficiency alternative that would otherwise be less cost-competitive.

Information and access policies address the real-world shortcomings of a market-based policy instrument. These policies enhance markets by providing information, technical assistance, or access to capital; they also address problems of misaligned incentives, such as between landlords and tenants. They are aimed at ensuring that consumers have access to efficient markets, where they can easily identify and act on least-cost options.

Strategic investment may be required to spur and shape the early adoption of new technologies and their markets. Research and development may yield examples on which to build. Policies can build markets for nascent technologies, such as Vermont's programs supporting the development of farm methane digesters, small-scale solar photovoltaic deployment, and bulk wood pellet infrastructure through the Clean Energy Development Fund, or multistate efforts to advance electric vehicles through the Zero

[40] U.S. Energy Information Administration, State Energy Data System

Emission Vehicle Action Plan. Strategic investment that is directed at the highest-cost necessary technologies for achieving Vermont's goals can reduce those costs, or achieve those emission reductions through mechanisms other than price alone. This allows price-based policies to drive optimization without unreasonable direct price impacts.

Codes and standards, such as building energy codes, appliance efficiency standards, vehicle fuel economy rules, and land use plans, serve to avoid lost efficiency opportunities in long-lived products and infrastructure using established technology. Such rules commonly require actions that are demonstrated to have a positive life-cycle economic benefit, and that lock in savings for consumers. Enforcement of these policies ensures that savings occur, and gives consumers confidence in the legitimacy of alternatives.

Vermont has already enacted some market-based policies, such as the Renewable Energy Standard in Act 56 of 2015 and our participation in the Regional Greenhouse Gas Initiative cap-and-trade system for electricity. Most of the recommendations in this CEP take the form of complementary policies: information and access, strategic investment, and codes and standards. In the energy futures modeled for the Total Energy Study, price signals are sufficient in themselves to drive fuel consumption behavior toward renewable substitutes. In reality, there are many reasons why the supply of, and demand for, renewable energy cannot be expected to automatically expand in response to increasing fossil fuel prices.

As shown in Exhibit 4-11, since 2000, the prices of fossil fuels used for heating and transportation have increased almost three-fold while consumption of those fuels remained flat. For households, which as a whole have simultaneously experienced a slow-down in wage growth over this period, this has resulted in a significant increase in the share of income going to purchases of energy, up from approximately 11% on average in 2000 to around 15% on average today.[41] The energy cost burden for the lowest-income households is now greater than 25% of income[42].

Because of increasing fossil fuel prices, businesses have also begun to see energy bills increasing faster than revenues, a possible departure from past reality when firms as a whole were consistently able to grow their revenues at least as fast as their energy costs. Small businesses with lean budgets and little inability to pass on costs to customers are particularly vulnerable to increasing energy costs.

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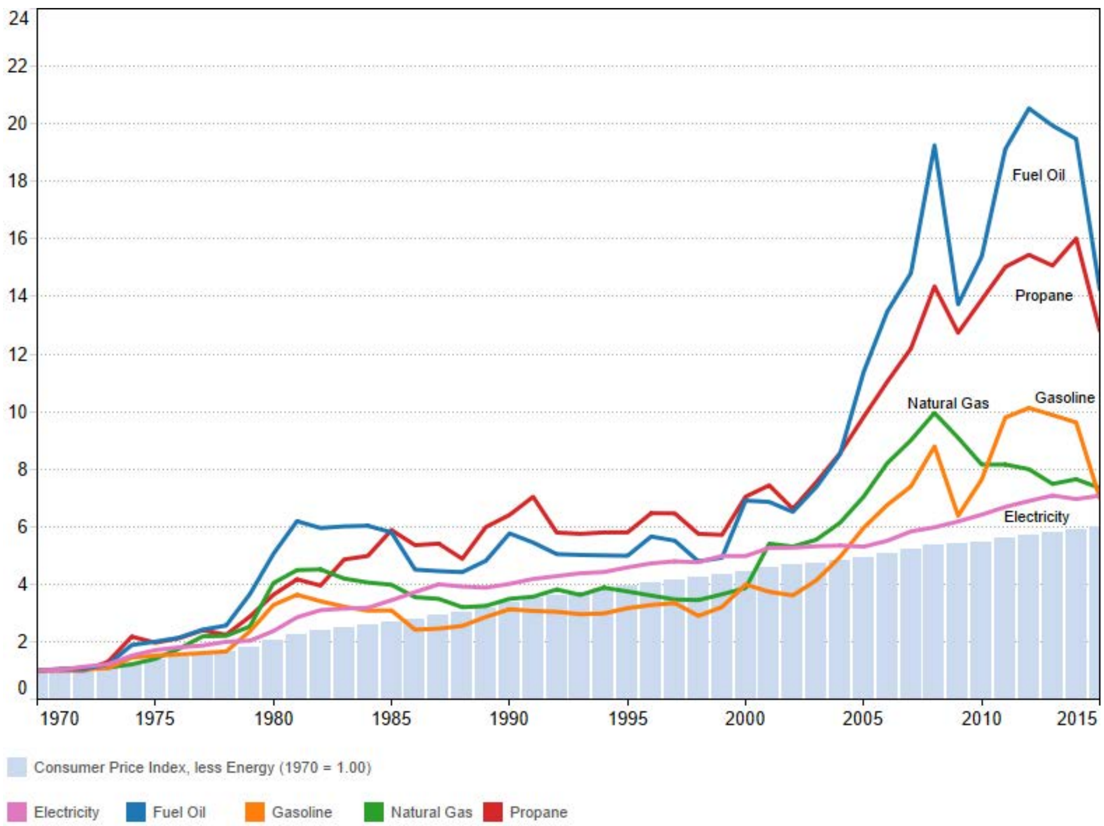
[41] U.S. Energy Information Administration and Federal Bureau of Economic Analysis.

[42] Jonathan Teller-Ellsberg, Benjamin Sovacool, Taylor Smith and Emily Lane, *Energy Costs and Burdens in Vermont: Burdensome for Whom? (*Energy Security and Justice Program, Vermont Law School's Institute for Energy and the Environment, 2014). This calculation does not include the consumption of energy for transportation, and thus very likely underestimates the energy cost burden for low-income groups.

Exhibit 4-11. Average Retail Fuel Prices Paid by Vermonters, 1970-2015 (1970=1.00)



Sources: U.S. Energy Information Administration, Federal Bureau of Labor Statistics, Vermont Department of Public Service

During this period of rising fossil fuel prices, it appears there has been some substitution away from fossil fuels toward wood heating in the residential and commercial sectors (see Exhibit 4-5), and at least some of the reduction in gasoline consumption is likely price-induced. Yet even though the generally higher petroleum price environment has improved the customer economics of renewable heat and transport energy, practical barriers remain to the development of a dependable renewable energy supply. This section of Chapter 4 identifies some of those barriers, and explains the role that non-price-based policy instruments can play to encourage the development of a functioning renewable energy marketplace in Vermont. Without such complimentary policies, market-based policies that rely exclusively on often erratic price signals to guide consumer behavior are unlikely to ensure that the lower lifetime costs of renewable alternatives will become a practical and accessible consumer option for households and businesses.

Designing Market-Based Policies

In addition to well-designed complementary policies, market-based policies themselves must be well-designed to be effective and sustainable. The CEP establishes the following guidelines for the development of market-based policies in Vermont:

- **Revenue Recycling:** When considering a market-based policy, a fundamental choice is whether that policy should be designed to generate net revenue for the state, which could then use the revenue to implement the types of complementary policies described above, or to otherwise advance state policy goals. For example, participation in the Regional Greenhouse Gas Initiative results in net revenue for energy efficiency programs. The other possibility is that other revenue sources could be replaced. Policy design should strike an appropriate balance, limiting and targeting net revenue to advance state policies.

- **Pace:** The pace of change in policy-driven energy pricing should be compatible with the time that consumers (whose behavior is supposed to be modified) require to change their behavior, and with the time it takes to build the infrastructure necessary to support those new behaviors. If consumers have no practical ability to transition their energy use, price-based policy may result in unavoidable increases in energy cost burdens. Complementary policies can and should support transition for these consumers. Different sectors may have different timelines over which customers can effectively respond to changes in energy prices. Simply increasing the price of the fuels that a given customer relies on should not be expected to automatically motivate a majority of consumers to undertake the expensive, up-front capital conversion expenditures that are necessary to prevent their energy-related outlays from increasing. For example, vehicle choice is made on a once-a-decade time scale; buildings last much longer, but unlike vehicles can be retrofitted. The location of a building, and thus its impact on transportation energy use, is practically unchangeable once the building is constructed, and the pace of new development is slow. Electric utility portfolios can change quite quickly by comparison with any of these other sectors.

- **Equity:** Energy use, including transportation, does not vary strongly with household income. As a result, a price-based energy policy can be relatively regressive when compared with other government policies or programs. Any market-based program should use revenue created by market-based policies (e.g., through allowance auctions or carbon tax revenue) to offset more regressive (rather than more progressive) taxes or other programs. Such a program should also consider equity among sectors (residential, commercial, industrial, transportation), to minimize any cross-subsidization that runs counter to state policy goals.

- **Competitiveness:** Government revenues and expenditures influence the cost of doing business in different jurisdictions. A market-based policy has the potential to shift those costs for businesses and residents in Vermont, and to attract or dissuade firms that are considering locating or expanding here. Where possible, Vermont should pursue policies that advance the state's attractiveness for business formation and growth. Regional or national market-based policies would reduce differences between Vermont and its neighbors that would likely emerge were Vermont to act alone. Regional consistency could also relieve concerns near Vermont's borders with other states.

Recommendation

Vermont should work with other states and provinces in our region, building upon existing regional initiatives including the Regional Greenhouse Gas Initiative, the Transportation Climate Initiative, and the Western Climate Initiative, to investigate and pursue options for market-based GHG emission policies that integrate with the other approaches described in this CEP, and are consistent with the principles regarding revenue recycling, pace, equity, and competitiveness detailed above.

5 Land Use and Siting

As we move toward generating more of our energy renewably and closer to home, it's no surprise that tensions between competing land uses will arise. For one thing, the *power density* — the amount of energy per given unit of volume, area, or mass — of existing renewables is orders of magnitude less than it is for fossil fuels. As a result, renewables require much more space on the landscape than do traditional, centralized generators. For another, renewable electric sources need to be sited where the renewable resource (wind, sun, water) exists, and where they can be cost-effectively built and connected to the grid — which often means greater visibility, at least when compared with the large, centralized, often distant conventional generation to which we've become accustomed. And if sited far from load, electric sources must be connected with adequate transmission, which is both a limiting factor in siting renewables and a siting challenge unto itself.

5.1 Land Use Choices

Every time we change or restrict uses on a piece of land — whether for energy production, residential or commercial development, agriculture, roads, or another purpose — we are making a decision that often precludes alternative uses (or preservation). These choices may affect the character, functionality, energy use, and climate resilience of the landscape and environment for decades to come.

Flat, sunny, open lands are optimal for capturing solar energy, and that energy can help grow food for humans and livestock, power our cars and heat for our buildings, and generate electricity for our homes and businesses. But those same lands are also attractive for conversion into those same residences and workplaces; and if left undeveloped, they may serve as important habitats for songbirds and other wildlife, an important part of the biodiversity that supports us all.

Our hilltops and mountaintops allow access to the strong, steady winds necessary for the scale of wind energy production that can make a significant contribution to our energy supply. Those same peaks capture rainfall and store snowpack that feeds our headwaters, which descend into the rivers that nurture fish and plants. Mountain ridgelines and peaks tend to sit in the center of our most significant blocks of wildlife habitat; these serve as important travel corridors for a range of species, offer refuges for native plant and animal species to adapt to a warming and crowded planet, and provide solace and sense of place to Vermonters and visitors alike.

Forests — especially in large, unfragmented blocks — offer critical habitat to many of our plant and animal species. They also filter air, sequester carbon, and contribute to flood resilience by absorbing large volumes of rainwater. Seventy-eight percent of Vermont is forested; and when managed properly, our forests also offer significant recreational and economic potential. Many Vermont homes, businesses, and institutions are heated with wood or pellets, and our extensive forest resources offer the potential to expand the use of wood for heat and combined heat and power to many more Vermonters, offsetting significant volumes of imported fossil fuels while keeping more of our dollars circulating in the local economy. But as with fossil fuels, burning wood releases emissions of harmful pollutants to the air we breathe, making it absolutely necessary to ensure that we rely on the most efficient, cleanest combustion technologies to minimize health and environmental impacts.

The use of watercourses in Vermont is not exempt from these competing priorities. Rivers are vital to fish as nurseries, spawning grounds, and habitats. Those fish attract anglers, while rapids and still waters attract boaters and other recreationists. And with every major rain event, we are reminded — more and more urgently these days — of how important natural river corridors are for flood resilience. Rivers traditionally served as the lifeblood of fledgling New England economies, powering our early mills. But the powering of our human needs has often compromised aquatic life, due to the damming and impoundment of watercourses, effectively isolating fish populations above and below dams and affecting the amount of oxygen and type of food and habitat left for the survivors. Modern hydropower facilities at existing dams have the potential to offer significant generation that can balance intermittent renewables such as wind or solar, but they face significant permitting challenges that are designed to protect the other vital functions of rivers.

Of course, Vermont's landscape is not limited to specific land cover types and natural resource features. Historic and modern settlement patterns contribute not only to our sense of place and home, but also to the ways we generate and use energy. Cities, downtowns, and other developed areas may have higher overall energy needs, and fewer places to site large-scale generation; but they also use energy more efficiently. Rural areas with potentially more space for generation might have lower loads but less-efficient energy use, particularly with respect to transportation.

The uses and values we impart to our lands and waters may seem to be in stark competition with each other. But more often than not, we can find complementarities and acceptable compromises if we are up to the challenge. This involves working together to name the competing uses and values and (much harder) our ultimate priorities for a given parcel of land, landscape, or region; then infusing those priorities into our land use planning, and translating that planning into regulations, processes, and siting guidelines. This work also asks us to think holistically — not only about societal values in our energy decisions, but also about the energy implications of our other societal decisions: where we put our homes and businesses, how we power and heat those buildings, and how we move people and goods among those places.

5.2 Regulatory Context

There are two primary, state-administered permitting pathways for developments in Vermont: 10 VSA § 6086 (Act 250) and 30 VSA § 248 (Section 248). Act 250 — Vermont's Land Use and Development Act, passed in 1970 — regulates non-energy generation and transmission development, including most commercial, industrial, and subdivision development. Nine district commissions, composed of citizens appointed by the governor and assisted by a district coordinator, review applications for compliance with 10 statutory criteria, found in 10 VSA § 6086.

Section 248 evolved out of utility regulatory statutes that govern public utilities and date back as far as the late 1800s. Today, Section 248 generally regulates electric generation and transmission, along with natural gas facilities. The statutory criteria that must be considered by the Public Service Board (PSB) — the three-member, quasi-judicial board with public utilities oversight — are defined in Title 30. In 1988, the bulk of the criteria defined in 10 VSA § 6086 (the "Act 250 criteria") were incorporated into Section 248, to provide a framework for review of the environmental impacts of energy projects.

The PSB is directed to give due consideration to the Act 250 environmental criteria in determining whether an energy project poses an undue adverse impact to the natural environment. In addition to these environmental criteria, the Board reviews projects for their economic impacts and costs, impacts on electric system stability and reliability, compliance with the state energy plan, public health and safety, and GHG impacts. However, certain criteria — such as "need" and GHG impacts — are waived for smaller-scale renewable generation projects. The Board also has the discretion to review environmental impacts above and beyond the specific environmental criteria adopted from Act 250.

Despite their similarities, there are substantial differences between Act 250 and Section 248, both in terms of criteria of review and the regulatory process. These have been explored in recent years, by the Legislature[43] and the Governor's Energy Generation Siting Policy Commission[44], as both bodies sought to review and compare the strengths and weaknesses of the two processes in order to design improvements, especially in terms of the weight given to town and regional plans.

5.3 The Importance of Planning

Decisions made about the location, scale, and design of a project are not created in a void, but rather in response to a suite of disparate levers, from incentives at the federal and state level to siting parameters imposed by the physical environment and available infrastructure, plus those generated by a deliberate planning process translated into regulatory constraints. Also important is the extent to which planning feeds into regulatory review and approval. In Act 250, for instance, a development project must be in conformance with the town and regional plan, along with a number of other criteria. In Section 248, town and regional plans are given due consideration as the Board determines whether a project, on balance of the criteria, is in the public good.

As energy projects become more distributed across the landscape, the role of town and regional plans naturally assumes greater relevance; yet these plans tend primarily to address non-energy development — where they have greater regulatory weight — in any detail, though there are excellent resources

43 legislature.vermont.gov/assets/Documents/2016/WorkGroups/Senate%20Natural%20Resources/Reports%20and%20Resources/W~Sen.%20Bray~Comparison-%20%2010%20Chapter%20151%20(Act%20250)%20and%2030%20VSA%20Section%20248~1-20-2015.pdf

44 sitingcommission.vermont.gov/sites/cep/files/Siting_Commission/Publications/Comparison%20Table%20248-250.pdf

available to towns that wish to undertake detailed energy planning.[45] Various attempts have been made over the years to address this, with varying levels of success. In 1988, the Legislature passed Act 200, the Growth Management Act, in an attempt to create a common set of planning guidelines for all levels of planning, and as a complement to Act 250. The Agency of Commerce & Community Development wrote a report in 2003[46] analyzing reasons for the ultimate failure of the parts of Act 200 that were designed to foster both coordinated planning among state agencies as well as vertical integration of state, regional, and local planning. At the end of the day, the complexity involved in this type of multi-dimensional planning proved too insurmountable a challenge.

5.4 Energy Siting Reform Initiatives

In response to the growing pains that have emerged as the state begins to move toward the realization of a clean energy portfolio, smaller-scale efforts to examine ways of improving planning and siting processes have emerged. The Governor's Energy Generation Siting Policy Commission produced a report in 2013[47] that contained a comprehensive package of reforms to address concerns with siting and permitting of larger-scale (larger than 500 kW) energy generation projects. While legislative action to adopt the recommendations has not yet been taken — making it impossible to gauge their effectiveness — state agencies have begun to address many of the recommendations that do not require statutory change.

Notably, the DPS has used limited available funds to embark on a two-year pilot program to address the first three recommendations of the Siting Commission, which all focused on enhanced energy planning by the regional planning commissions (RPCs). Three RPCs — Bennington County, Two Rivers-Ottauquechee, and Northwest — are currently working with the towns in their regions and a variety of stakeholders to ascertain their regions' renewable energy potential and to comprehensively address their energy needs (electricity, heat, and transportation) through 2050. The towns within each region will determine the ultimate success of the energy plans; if the effort proves fruitful and funding is made available, it could be expanded statewide. The more active towns and regions become in energy planning, the greater the opportunities for addressing and minimizing potential land use conflicts before they arise.

Per Act 56, a Solar Siting Task Force has worked throughout the summer and fall of 2015 to study the design, siting, and regulatory review of solar electric generation facilities, and to provide a report to the

[45] Vermont Natural Resources Council and Vermont League of Cities and Towns, *Energy Planning and Implementation Guidebook for Vermont Communities*, vnrc.org/wp-content/uploads/2012/08/Final-Guide-4-27-11.pdf

[46] Vermont Agency of Commerce & Community Development, *Status Report: 15 Years after Act 200*, accd.vermont.gov/sites/accd/files/Documents/strongcommunities/cd/planning/ACT200_15Years.doc

[47] Energy Siting Policy Commission, *Siting Electric Generation in Vermont: Analysis and Recommendations,* (2013), sitingcommission.vermont.gov/sites/cep/files/Siting_Commission/Publications/FinalReport/Final%20Report%20-%20Energy%20Generation%20Siting%20Policy%20Commission%2004-30-13.pdf

Legislature in the form of proposed legislation. While the Task Force's work is specific to solar, it may provide insight into improving the siting for other energy resources. This plan's chapters on meeting electric demand and energy supply resources will explore siting challenges to each of those resources in depth, as well as offering insights into the land use impacts for the state of various potential 2050 electric portfolios.

An obvious solution has not yet materialized for addressing the natural tensions that emerge as our energy resources become more visible. But at least Vermont is in good company, as our neighboring states, the nation, and other countries similarly attempt to transform the way we use and consume energy. A 2011 paper from Rutgers professor Clinton Andrews, et al, *Alternative Energy Sources and Land Use*, offers some perspective[48]. Globally, the authors expect energy demand between 2010 and 2030 to increase from 140,000 terawatt-hours per year (TWh/yr) to 199,000 TWh/yr. The researchers group energy sources into three categories based on land intensity, or land area required for delivering 1 TWh/yr. In Vermont, the least land-intensive energy resources are all either non-renewable or extremely limited: nuclear, geothermal, coal, solar thermal, and natural gas. In the middle of the pack come most of the renewables: solar PV, hydropower, and wind, as well as petroleum. Biofuels are the most land-intensive resources — and that will preclude them, the researchers assert, from becoming a globally important energy source.

5.5 Siting and Land Use Principles

Although this plan does not attempt to solve the tensions inherent to energy development in land use planning and regulation, the following set of principles attempts to capture complementary land use opportunities; or, in the presence of unresolvable conflicts, to offer a framework for analytical decision making (specific recommendations related to siting and land use may be found in sector- and technology-specific chapters of this plan):

1. Energy and non-energy land use planning should be integrated as much as possible at the local, regional, and state levels.
2. Energy (30 V.S.A. 248) and non-energy (Act 250) land use regulatory processes should be complement each other to the extent practicable.
3. Energy elements of Act 250 criteria, and land use elements of Section 248 criteria, should reflect the integrated planning and complementary regulatory review principles.
4. Energy development that meets needs while avoiding or mitigating negative impacts on other state, regional, and local goals and priorities, including economic, environmental, and health priorities identified in Chapter 3, and that takes statewide land use goals[49] into account, should be promoted.

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[48] i.i.cbsi.com/cnwk.1d/i/tim//2010/05/29/LandUseAndrews.JPG

[49] Local and regional planning processes are guided by Vermont state law (24 V.S.A., Chapter 117) to not only direct development so as to maintain the historic settlement pattern, but also to protect natural and historic

5. Energy development that enhances other state, regional, and local goals and priorities, including reduction in the state's and region's GHG footprint, improvement in air quality, and opportunities to develop local economies, should be prioritized.

resources, including significant natural and fragile areas, outstanding water resources, significant scenic roads, waterways, views, and important historic structures, sites, or districts.

6 Energy Financing

Advancement toward the goals set in this CEP will require expanded access to funding and financing to support project development along with investment in clean energy businesses in the state. The 2011 CEP identified a range of finance-related recommendations, and much progress has been made since then. Follow-on activities that contributed to this progress include the 2012 Thermal Efficiency Task Force, two governor-sponsored Clean Energy Finance Summits, strategic planning for the Clean Energy Development Fund, and others. This chapter provides updates on the progress, a review of relevant finance tools and policies, and recommendations on priority strategies that will help to further expand access to project finance in the coming years. Discussion related to funding for particular topic areas such as thermal efficiency or potential new sources of public revenue can be found in relevant sections of the CEP.

6.1 Magnitude of the Challenge

Meeting the finance challenge associated with renewable energy and energy efficiency goals in the near term will require a substantial infusion of capital — from an estimated $500 million above the current baseline invested to reach a target of $1 billion invested by 2020[50], to $28.7 billion needed by 2030.[51] A more recent analysis developed by the Energy Action Network (Exhibit 6-1) puts this figure at over $33 billion in total needed to achieve the state's energy goals. In comparison, Vermonters spent over $3.26 billion on total energy expenditures in 2013, according to the U.S. Energy Information Administration.

In 2013, Vermont had the 14th highest expenditure on energy in the U.S. at $5,196 per capita, despite a low energy use of only 213 million Btu per capita, or 44th in the nation.[52] The state's high energy expenditure per capita provides opportunity for cost savings and stimulation of the local economy through investment in clean energy.

[50] Vermont Agency of Commerce & Community Development, *State of Vermont 2020 Comprehensive Economic Development Strategy*, accd.vermont.gov/sites/accd/files/VT%202020%20CEDS.pdf; p. 28

[51] Nancy Wasserman and Bob Barton, *Mobilizing Capital to Transform Vermont's Energy/Economy* (Energy Action Network, October 2012), pp. 13-18

[52] U.S. Energy Information Administration, www.eia.gov/state/rankings/?sid=US#/series/225 and www.eia.gov/state/rankings/?sid=VT#series/12

Exhibit 6-1. Potential Scope of Financing Needed in Vermont by 2050

	Selected Technologies		Total Current Installed Capacity	Total Potential Market	Total Unfilled Potential Cost ($ Millions)
1	Wind		214 MW	329 MW	$312
2	Solar PV		87 MW	2,248 MW	$6,000
3	Energy Efficiency	Electric	993 GWh	5,219 GWh	$1,884
		Thermal	218,000 MMBtu	32,000,000 MMBtu	$9,699
4	Bioenergy Electric Generation[1]		88 MW	132 MW	$158
5	Transportation		801 EVs 43 Public Charging Stations	~400,000 EVs ~127,000 Bio Vehicles ~20,000 Bio Trucks ~500 Public & 250,000 Home EV Charging Stations	$415 for Vehicles $780 for Charging $1,195 Total
6	Thermal Fuel Switching		N/A	20,000,000 MMBtu	$6,878
7	Electric Grid Upgrades[2]		N/A	N/A	$7,034
	TOTAL		N/A	N/A	$33,160

coalition for green capital ENERGY ACTION NETWORK

Notes & Sources: (1) Only includes power generation. Does not include bioenergy used for end-use efficiency. (2) Includes end-user smart-grid technology, and grid investments. Potential markets based on analysis by EAN. 1

Moving forward will require not only new energy policies and programs, such as those created by Act 56 of 2015, but also further development and application of finance tools that expand the range of available options. Some finance products currently in use, such as solar leases and cash-flow-positive commercial energy efficiency loans, make sense economically for the customer and offer immediate savings. As more finance institutions gain experience with renewable technologies and energy efficiency upgrades, their ability to assess risk and develop new finance products will improve, helping provide greater access to affordable capital. However, a wider range of finance tools and policies is either in use, in development, or under consideration in the U.S. It makes sense for Vermont to invest in some of these, while others may be better suited to states that have greater capacity in the near term.

One issue that loomed large over the clean energy finance landscape resolved on December 18, 2015, when President Obama signed the trillion dollar Omnibus Appropriations Act, which included an extension of tax credits for solar and wind, among other provisions. Although the credits are slated to decrease differentially over the next five years for the various renewable technologies, they will remain a key driver of clean energy investment. This will enable businesses to plan their projects with a level of predictability needed to maintain project development pipelines.

State tax credits for installation of renewable energy equipment remain tied to the federal tax credits. As the federal tax credits decline over the next several years, it may make sense for the state consider decoupling the state and federal tax credits in light of how other policies are playing out (e.g., RES, standard offer, net metering).

The state continues to monitor trends and explore opportunities regarding clean energy finance that arise through the DPS and other entities directly involved with finance activities, such as the Office of the Treasurer and the Vermont Economic Development Authority. Following sections of this chapter will review progress regarding finance, examine current finance tools and policies, and review the prospects for applying others to help meet the growing demand for affordable capital.

6.2 Background on Finance for Clean Energy

Public funding remains central to facilitating increases in energy efficiency investment in Vermont's buildings, and to deploying renewable-energy production technologies. Cash incentives provided by the state help stimulate demand by decreasing the up-front cost of an investment, but they cannot cover the full price. Ultimately, most of the investments made in efficiency and renewables will need to come from private capital, either from savings or from financing. Well-designed upfront incentives that work in concert with financing options can attract sufficient investment with the least possible public contribution. This section looks at recent trends, activities, and progress related to clean energy finance.

National Markets Ramping Up

Since the 2011 CEP, investments to support clean energy projects have increased substantially in the U.S. Clean energy investment in all classes reached $51.8 billion in 2014, five times higher than a decade before, and totaled $265 billion from 2010 to 2014.[53] In just one part of the clean energy industry, Vermont added 38 megawatts (MW) of solar electric capacity in 2014 — a $76 million investment across the state, a 63% increase over the year before.[54]

As demand grows for renewable energy and energy efficiency products and services, spurred by state and national policies, concerns about climate change, and investor interest, innovation is occurring in capital markets to provide lower-cost, scalable finance tools. There is activity on asset-backed securitization, yieldcos, bonds, and other financial products along with policies that include credit enhancement and warehousing.

Achieving the scale of investment needed to reach Vermont's and other states' energy goals will require reductions in soft costs, including costs of financing. A recent report by the National Renewable Energy Laboratory (NREL) stated that unlocking long-term investment in clean energy will require access to private investment that has historically been unavailable to renewable-energy project finance: pension funds, mutual funds, and private wealth accounts with assets that are primarily invested in debt and equity securities that are liquid, tradable, and priced by the market. Traditionally, renewable energy investment is project-financed and does not have these characteristics, which limits the supply and raises the cost of investment capital.[55] Similar circumstances also apply to energy efficiency, but due to the nature of such investments (e.g., returns on investment are derived from savings obtained), risk and

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53 Michael Mendelsohn and Marley Urdanick, *Sustainable Energy in America, 2015 Factbook* (Bloomberg New Energy Finance and Business Council for Sustainable Energy, 2015). Total clean energy investment in the U.S. across all asset classes (asset finance, public markets, venture capital/private equity) as well as corporate and government R&D, and small distributed capacity (rooftop solar). www.bcse.org/wp-content/uploads/2015-Sustainable-Energy-in-America-Factbook.pdf

54 Solar Energy Industries of America, "Vermont Posts Significant Gains in Solar Capacity in 2014" (April 2, 2015), www.seia.org/news/vermont-posts-significant-gains-solar-capacity-2014

55 Michael Mendelsohn, Marley Urdanick and John Joshi, *Credit Enhancements and Capital Markets to Fund Solar Deployment: Leveraging Public Funds to Open Private Sector Investment,* (National Renewable Energy Laboratory 2015), www.nrel.gov/docs/fy15osti/62618.pdf, p. 2

return are more difficult to project. As noted below, renewables and efficiency investment options are currently being developed to address this need.

Making progress toward lowering costs will require addressing the perceptions of risk that limit investor confidence and thus participation. These risks may relate to the performance of any particular technology over time, plus regulatory policy uncertainty and the creditworthiness of participants. Long-term success will depend on demonstrating that assets perform at expected levels, and developing a track record that documents this history.[56]

The overall transition toward market maturity is in its early stages. However, there has been notable progress recently, with development of new finance products that include the solar industry's first securitization[57] and the Warehouse for Energy Efficiency Loans (WHEEL).[58] These initial steps herald the emergence of secondary markets with new asset classes. There has also been progress with formation of *yieldcos* (publicly traded yield companies), which are now available and traded on public exchanges. At this stage, securitization and yieldcos favor larger players with substantial development pipelines.

Other instruments, such as real estate investment trusts (REITs), offer limited possibilities for investors that seek to participate in the emerging markets for clean energy investment. Making REITs more available for clean energy investment will require a ruling by the IRS or legislative action. Similarly, master limited partnerships (MLPs) offer another potential avenue for investment, but their use will also require new legislation.

Interest is growing rapidly in green bonds or climate-aligned bonds. According to the Climate Bonds Initiative, the total climate-aligned bonds sector stands at $597.7 billion, a 20% increase from last year. Of this total, $51 billion comes from the United States, and almost a third of this year's increase of $95 billion was due to the rapid growth of the labeled green bond market. Transportation and energy lead the way in this realm, which altogether includes bond issuers spanning those two industries plus buildings and industry, agriculture and forestry, waste and pollution, and water. [59]

Among the entrants in this field is a $150 million, AAA-rated green asset-backed security issued by the Hawaii State Department of Business, Economic Development and Tourism. This successful bond issuance is backed and repaid by a green infrastructure fee assessed on all ratepayers. The proceeds of the issuance are managed by Hawaii's Green Infrastructure Authority to support the Green Energy Market Securitization (GEMS) program for loans to consumers, to fund the installation of distributed solar

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[56] Mendelsohn, Urdanick and Joshi, p. iv

[57] SolarCity, "SolarCity Completes Industry's First Securitization of Distributed Solar Energy," (press release, November 21, 2013), investors.solarcity.com/releasedetail.cfm?ReleaseID=808982

[58] Citi, "Citi and Renew Financial Announce First Ever Energy Efficiency Loan Asset-Backed Security Transaction" (press release, June 15, 2015), www.businesswire.com/news/home/20150615006147/en/Citi-Renew-Financial-Announce-Energy-Efficiency-Loan

[59] Climate Bonds Initiative, *Bonds and Climate Change: The State of the Market in 2015* (July 2015), www.climatebonds.net/resources/publications/bonds-climate-change-2015

photovoltaic panels, inverters, and monitoring devices.[60] This innovative finance model has potential for replication in other states.

While much of the financing innovation is coming from large-scale companies and financial intermediaries, these activities have potential implications for Vermont. Technological advances coupled with the use of emerging finance tools will remain central to developing mature clean energy markets.

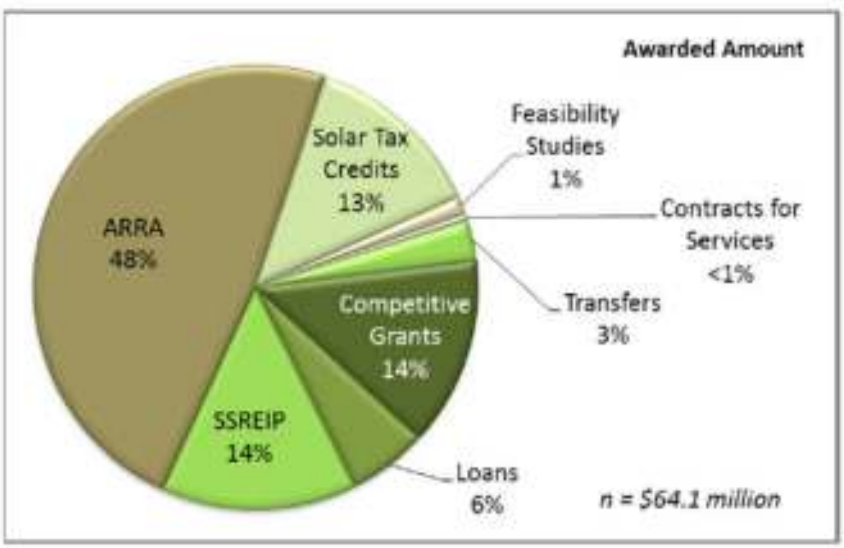
6.3 Recent State Clean Energy Finance Activities (2012-2015)

For a brief review of key clean energy finance-related activities undertaken by the state since the release of the 2011 CEP, see Chapter 2. This section describes recent activities of importance in greater detail.

Clean Energy Development Fund Strategic Plan (CEDF, 2012-2015)

The CEDF is one of the state's primary vehicles for providing resources to support advancement of clean energy. Historically, the bulk of the funding went to the Small Scale Renewable Energy Incentive Program (SSREIP). Recent decreases in funding required a re-prioritization for how funds would be allocated. In 2012, the CEDF issued a five-year strategic plan, which was adopted by the Clean Energy Development Board to provide the new focus.

Exhibit 6-2. CEDF Awards by Funding Types (2006-2013)



Source: Evaluation of the Vermont Clean Energy Development Fund, NMR Group, Inc., et. al.

From 2006 to 2013, the CEDF deployed $64.1 million via 3,983 awards for investment in clean energy technologies and projects around the state. Awards included competitive grants, loans, tax credits, incentive payments, feasibility studies, and contracts for services from state and American Recovery and Reinvestment Act (ARRA) resources (Exhibit 6-2). While this investment was, and continues to be, important to progress toward state energy goals, even more important are the resources and outcomes leveraged by CEDF activities. Overall, the fund generated over $196 million in additional private sector

[60] GEMS Financing Program, Hawaii Green Infrastructure Authority, http://gems.hawaii.gov/learn-more/faqs/

investment, for a 3.2 to 1 leverage ratio and a total of over $260 million for the state's clean energy industry.[61]

Since its formation in 2005, the CEDF has invested over $15 million in clean energy resources through the SSREIP and leveraged an additional $88 million.[62] One insight gleaned from this success story highlights the need to gradually taper incentive payments for more mature technologies, to apply resources toward finance strategies for solar PV, and to focus incentive resources on other viable technologies in emerging local markets.

Building on this insight, the CEDF 2015 work plan includes new finance programs using credit enhancements that would help finance institutions gain more experience with financing renewable energy technologies. This new direction led the fund to provide credit enhancements to foster finance for solar PV in Windham County ($300,000) and for community solar statewide in 2015 ($125,000). These new programs complement the $700,000 in credit enhancements supplied to financial institutions via the Thermal Energy Finance Pilot project, begun by DPS in July 2014 and supported by the CEDF. The CEDF also deployed $200,000 to support credit enhancements for the Residential PACE program, plus over $255,000 in credit enhancements for the loan program run by NeighborWorks of Western Vermont.

Thermal Efficiency Task Force (2012-2013)

Created in 2012 to ensure an integrated, comprehensive, statewide whole-building approach to thermal energy efficiency, the Thermal Efficiency Task Force (TETF) included a focus on funding and financing. Its Finance and Funding Subcommittee was charged with making recommendations regarding the amount of money needed to achieve the state's thermal efficiency goals in 10 V.S.A. § 581, and to identify financing mechanisms and funding sources to achieve those goals. The group recognized that reaching these goals for building-energy efficiency will require a combination of funding and financing tools, along with appropriate risk mitigation features, with an assumption that a significant majority of the resources will come from private, not public, sources.[63]

Full implementation between 2014 and 2020 of the ideas and recommendations laid out in the TETF report was estimated to cost about $1 billion, with funding from various public sources estimated at about $356 million and $687 million coming from private sector financing and investment. The budgets required to meet the state's building efficiency goals showed that a significant majority of the overall resources would come from financing, not funding. In 2014, every dollar in funding was expected to leverage about $1.40 in financing or private funding. The task force projected this rate to increase from 1.40 to 1 in 2014 to 2.60 to 1 by 2020, averaging 1.90 to 1 over the full term.[64]

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[61] NMR Group, Inc. & Energy Futures Group, Inc., *Evaluation of the Vermont Clean Energy Development Fund* (February 25, 2015), p. V

[62] Ibid, p. 56

[63] Thermal Efficiency Task Force, *Analysis and Recommendations — A Report to the Vermont Legislature,* (January 2013), p. 79

[64] Ibid, pp. 80-81

The TETF Funding and Finance Subcommittee developed a list of recommendations of financing options in tiers representing those most likely to offer near-term benefits. These include:

Tier One

1. *Private activity bonds* — bonds used to finance an IRS-defined set of activities, including qualified residential rental projects, public educational facilities, and green building/sustainable design projects.

2. *Energy-aligned leases* or *green leases* — commercial leases that specify how the costs and benefits of energy improvements will be shared.

3. *On-bill financing* — finance provided to customers, and repaid through the utility or fuel bill. The assessment may or may not stay with the meter or house.

4. *Energy-efficient mortgages* (EEMs) and e*nergy improvement mortgages* (EIMs) — mortgages that consider energy savings as income in calculating the debt-to-income ratio, and that allow the inclusion of energy improvement costs to be rolled into the purchase mortgage.

5. *Public purpose performance contracting* — a variation on energy service contracting through which smaller and/or less profitable non-residential buildings benefit from comprehensive energy upgrades. This might include aggregation strategies to bundle groups of buildings.

6. *Private financing with performance guarantees* — loan products that are backed by a performance guarantee, should a retrofitted building fail to live up to its cost savings projections.

Tier Two

1. *Bonds* — greater use of state allocation of tax subsidy bonds such as Qualified Energy Conservation Bonds (QECBs).

2. *Expanded PACE program* to involve the commercial sector, including multi-family properties.

3. *Linked deposits* — a mechanism through which the state provides financial incentive for private lending institutions to make more loans for efficiency measures and renewables.

4. *Crowdfunding* — a new investment strategy intended to generate many small investments, authorized through the federal JOBS Act of 2012.

5. *Managed Energy Service Agreements (MESA) and Efficiency Service Agreements (ESA)* — similar to power purchase agreements (PPAs), but for energy efficiency products and/or services (e.g., energy-efficient furnaces).

Tier Three

1. *Lending/loan purchase program/secondary market* — a mechanism through which the state or other financial institutions buy private loans.

The subcommittee concluded at the end of 2012 that:

> *… many financing products were poised and available for multiple markets, buildings and customer types that are significantly under-used for energy efficiency improvements. Consumer demand is not sufficient to drive new approaches to financing energy efficiency. A significant part of any effort in support of the TETF goals will need to be the enlistment and engagement of lenders to offer financing for participants.* ***Partnerships between program administrators and lenders will be a key component of a successful initiative*** [emphasis added]. *But consumer interest must first be galvanized by other program activities, public policies, customer outreach and sales and financial incentives addressed in this report.*[65]

One aspect of finance-related progress since the TETF is the Thermal Energy Finance Pilot program, which provides affordable finance for home thermal energy upgrades, with a focus on low- and modest-income Vermonters. The pilot includes creation of an on-bill repayment option, through which homeowners can repay loans for upgrades via their regular fuel bill. As of August 2015, the new on-bill repayment feature was under development between the Opportunities Credit Union in Burlington and select fuel dealers. (For details, see Thermal Energy Finance Pilot Project, later in this chapter.)

Since July 2014, customers of Green Mountain Power have had the opportunity to pay for home energy improvement loans from NeighborWorks of Western Vermont via an on-bill repayment option with GMP. The service allows GMP customer to access loans from NeighborWorks and make monthly installment payments when they pay their GMP bill. Loans may be for thermal and electric efficiency measures, renewable energy, and other services that advance the state's energy plan. Any GMP customer anywhere in Vermont who owns a home or apartment building, up to four units, may participate. Loans are up to $15,000, with up to 10 years to pay back.[66]

VEIC has also advanced the TETF recommendation of a public purpose energy service company (PPESCO) with the entrance of Commons Energy, which is now operating in Vermont. (For more on the PPESCO, see the section titled Energy Service Companies/Public Purpose Energy Service Companies, later in this chapter. For more on the TETF, see chapters 2 and 7.)

Vermont Sustainable Energy Loan Fund (2013)

Since 2010, the Vermont Economic Development Authority (VEDA) has provided $27.8 million in financing for commercial and agricultural energy generation and efficiency projects, supporting a variety of investments in efficiency, hydropower, solar photovoltaic, wind, digester, and biomass initiatives

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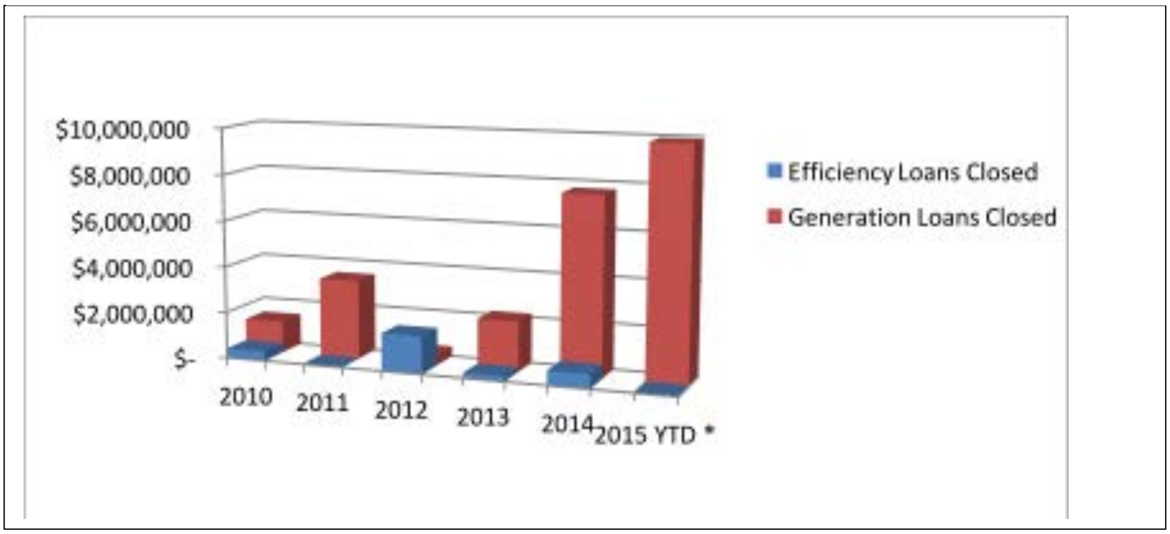
[65] Thermal Efficiency Task Force, *Report to the Legislature*, p. 98

[66] Note that the NeighborWorks Energy Loan is available statewide, but only customers of GMP have access to the on-bill repayment option. NeighborWorks of Western Vermont, "New On Bill Program Makes it Easier for Vermonters to Make Energy Improvements and Pay for Renewable Energy" (press release, July 29, 2014), www.nwwvt.org/bill-repayment-energy-improvements/; and NeighborWorks H.E.A.T. Squad, *Paying for Energy Improvements*, heatsquad.org/affordable-financing/

(Exhibit 6-3). With loans for renewable energy generation partway through 2015 already topping the 2014 total, VEDA has significantly increased its financing for clean energy projects around the state.

VEDA expanded its capacity to provide financing for clean energy during the 2013 legislative session, when it and numerous other organizations worked with the Legislature to secure passage of H.395 (Act 87 of 2013). This enabling legislation provided for new financing for commercial, small business, and agricultural sustainable-energy projects through the Vermont Sustainable Energy Loan Fund. According to the statute, the new fund's purpose is to enable VEDA "to make loans and provide other forms of financing for projects that stimulate and encourage development and deployment of sustainable energy projects in the State of Vermont," with *sustainable energy* defined as energy efficiency, renewable energy, and technologies that enhance or support the development and implementation of renewable energy or energy efficiency, or both.[67]

Exhibit 6-3. VEDA Cumulative Efficiency & Generation Loans (2010 to 2015 YTD)



** Includes $8,901,486 in Energy Generation loans approved in 2015 YTD with closings pending; Source: Vermont Economic Development Authority*

The Sustainable Energy Loan Fund has four separate programs:[68]

- *Small Business Energy Loan Program* — loans up to $350,000 for smaller qualifying commercial sustainable energy projects.
- *Commercial Energy Loan Program* — loans up to $2.0 million for relatively larger qualifying sustainable energy projects.
- *Agricultural Energy Loan Program* — loans for qualifying agriculture- and forest-product-based sustainable energy projects.

[67] 10 VSA §280cc

[68] Vermont Economic Development Authority, "New Sustainable Energy Financing Available at VEDA" (press release, Sept. 17, 2013), www.veda.org/newsevents/press-releases/sustainable-energy-financing-available/

- *Energy Loan Guarantee Program* — loan guarantees to participating financial institutions that cover loans made to businesses for improving their overall energy efficiency.

In addition to Sustainable Energy Loan Program products, VEDA also offers an Electric Vehicle Charging Station Loan Program.

During the period when H.395 was developed, VEDA worked with Efficiency Vermont and DPS on a DOE-funded initiative to build what became the Energy Loan Guarantee Program, which is backed by a VEDA-funded reserve and a DOE-funded reserve through the DPS. Initially, the program investigated qualified energy conservation bonds (QECBs) as a key feature in providing capital for loans to commercial energy efficiency projects.[69] But the terms for QECBs were not workable, so the participants worked with VEDA to identify an alternate pathway.

Because VEDA maintains capacity to sell bonds to fund its loans, and continues to serve as a central organization helping to advance clean-energy finance activities in the state, future efforts should engage VEDA and the Treasurer's Office in exploring options for using the state's allocation of tax subsidy bonds such as QECBs, or other relevant bond finance options. Since the initial efforts by the state to use QECBs in 2013, national experience with QECB issuance has increased, with 187 projects now financed in 36 states for over $1 billion.[70] The DPS encourages looking for opportunities to deploy QECBs to finance energy retrofits. If the state's allocation of QECBs are not used by FY18, DPS recommends allocating these resources for use by the state in its own buildings.

Local Investment Advisory Committee (2013-2015)

During the 2013-2014 session, the Legislature passed S.220 (Act 199 of 2014), which authorized the use of up to 10% of the state's average daily cash balance to be disbursed for local investments at the state treasurer's discretion, consistent with the Uniform Prudent Investor Act with recommendations from the Local Investment Advisory Committee (LIAC). The committee was specifically charged to "invite regularly State organizations, citizens groups, and members of the public to Advisory Committee meetings to present information on needs for local investment, capital gaps, and proposals for financing; and to consult with constituents and review feedback on changes and needs in the local and State investment and financing environments."[71]

Among the activities completed, the Treasurer's Office was authorized to extend a line of credit to VEDA to support its activities, including commercial energy efficiency and renewable energy capacity. This was

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[69] QECBs are bonds that enable qualified state, tribal and local government issuers to borrow money at attractive rates to fund energy conservation projects. See U.S. Office of Energy Efficiency and Renewable Energy (EERE), *Qualified Energy Conservation Bonds*, energy.gov/eere/slsc/qualified-energy-conservation-bonds. For addition information on bonding tools, see EERE, *Bonding Tools*, energy.gov/eere/slsc/bonding-tools.

[70] *Qualified Energy Conservation Bond (QECB) Update*. State & Local Energy Report, *http://stateenergyreport.com/2015/02/12/qecb-update/*

[71] Office of the State Treasurer, Report on the Findings and Recommendations Required by Section 220 of Act 199 of 2014 (memo, January 15, 2015), p. 1, *www.vermonttreasurer.gov/sites/treasurer/files/pdf/misc/LIAC%20Report.1.15.2015.pdf*

intended to lower VEDA's reliance on outside investment bank financing, and to lower the cost for entities financing through VEDA, with the aim of supporting Vermont jobs and economic development with a significant focus on commercial energy. The commitment was for up to $10 million in financing, in terms acceptable to the treasurer with a guaranteed repayment. The following other measures were taken:[72]

- A residential energy credit facility was implemented, with a maximum commitment of $6.5 million.
- $2 million was committed to NeighborWorks of Western Vermont for its statewide residential energy efficiency program.
- A VHFA multi-family energy financing strategy received $2.8 million for VHFA's 2014 multifamily bond transaction, which included energy efficiency improvements.
- Up to $8 million was allocated, pursuant to the 2014 Capital Bill (Act 178 of 2014, Section 41), to create a state energy revolving fund for loans to be used to make cost-effective energy improvements that focus on bringing older state buildings up to Energy Star standards or better.
- Activities to stimulate local investment included the application of existing moral obligation authority to VHFA multi-family financing, taken in conjunction with the energy initiatives cited above; and the development of a loan program for public and private groups, to develop electric vehicle charging stations using funds from the State Infrastructure Bank, to be administered by VEDA.

As one example of progress, in 2014 VFHA used its share of the local investments to begin undertaking energy efficiency projects at affordable rental units for low-income seniors around the state.[73]

These and subsequent efforts to deploy residual funds demonstrate a commitment by the state to help identify gaps in finance markets, and use state resources to spur clean energy-related activities. However, there are limits to the terms under which the Office of the State Treasurer can effectively operate. For example, any local investments must consider the need to have ample cash to meet the state's obligations during "low" periods, requiring maturity periods to be kept somewhat conservative for the investment portfolio.[74]

Thermal Energy Finance Pilot Project

The Thermal Energy Finance Pilot project (TEF Pilot) is sponsored by the DPS and VLITE in partnership with Efficiency Vermont, the Vermont Fuel Dealers Association, VSECU, and Opportunities Credit Union (OCU). The program provides access to affordable finance for home thermal-energy upgrades, with a focus on low- and moderate-income Vermonters. Using $700,000 in funding

[72] State Treasurer, *Report on Section 220 of Act 199*, p. 2

[73] Leslie Black-Pumeau, *Smart Financing Promotes Smart Energy Use in Vermont* (Vermont Housing Finance Agency, February 5, 2014), www.vhfa.org/node/7860

[74] State Treasurer, *Report on Section 220 of Act 199*, p. 4

supplied by the DPS, VLITE, and DOE, the pilot provides credit enhancements — including interest rate buy-down and loan loss reserves — to reduce credit risk for participating financial institutions. The two credit unions, selected via competitive solicitation in 2014, offer the program's "Heat Saver Loan" with interest rates as low as 0% and terms up to 15 years for income-qualified borrowers. Home heating technologies and services eligible for finance include efficient oil- or gas-fired furnaces and boilers, advanced wood pellet furnaces, cold-climate heat pumps, solar hot water systems, and home weatherization activities. Borrowers must work with a qualifying contractor that participates in the Efficiency Excellence Network (EEN), a venture of Efficiency Vermont. The EEN is a designation given to participating residential contractors that meet additional Efficiency Vermont training requirements.

Initial response to the program has been positive, with over 100 fuel dealers and building energy contractors now eligible to promote access to the new finance product among their customers. As of the end of the first program year in September, the credit unions had issued 97 Heat Saver Loans totaling $1.19 million for thermal energy improvements and using $205,000 in IRB funds. Thirty-eight of those 97 loans went to households earning less than 80% of median income. Homeowners in 64 communities around the state performed upgrades via 51 participating companies, 19 of which completed more than one project.[75]

This new model is being driven by companies that are interested in selling energy efficiency products and services, and by partnerships between the energy efficiency companies and fuel dealers who see new market opportunities. Access to finance becomes a selling feature, which can help customers envision a low-cost pathway to making home energy upgrades.

Initial progress indicates the potential for such finance programs to complement existing tools in the state's clean energy tool kit. The pilot is slated to run into 2016, after which the DPS and program partners will evaluate its implications in the context of other activities inside and outside of the Department, and priorities laid out in this CEP. Given the limited public funds that are available to achieve energy goals, understanding the role that finance programs can play in the emergence of clean energy markets is essential.

6.4 Related Activities

This section summarizes some recent non-governmental efforts focused on finance for clean energy.

Energy Action Network (2012-2015)

Beginning in 2012, the Energy Action Network (EAN) convened stakeholders interested in clean energy finance through its Capital Mobilization Working Group. They set a goal of mobilizing capital on a large scale to fund transformative investments in energy efficiency and renewables — including public-private partnerships and innovative finance models — across all energy sectors in Vermont.[76] EAN

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[75] More information on the Heat Saver Loan can be found at www.HeatSaverLoan.com.

[76] Energy Action Network, *Capital Mobilization Projects*, eanvt.org/capital-mobilization

commissioned a report, *Mobilizing Capital to Transform Vermont's Energy/Economy*, which details a range of projections on financing known technologies and behaviors.

The report describes a need for over $28.7 billion in financing to meet a goal, set by the Energy Action Network in 2009, of meeting 80% of the state's energy needs with renewables and efficiency measures by 2030. The total projected amount includes $14 billion for the purchase of electric vehicles; $5.9 billion to retrofit existing buildings ($3.77 billion for residential, the rest for commercial); $2 billion for utility-owned and in-state distributed solar, wind, biomass, and hydroelectric generation; $1.95 billion for the purchase and installation of efficient pellet and wood burners; $1.7 billion each for small, in-state distributed renewable energy systems and solar thermal systems; and $750 million for the purchase and installation of residential and commercial geothermal systems.[77]

Mobilizing Capital highlights the attributes of over two dozen mechanisms — including government policies, tolls and user fees, expanded use of existing funds managed by government and foundations, alternate financing structures and products, better promotion and use of existing financing mechanisms, coordinated service delivery models, enhancements and alternative approaches to repayment collection, and project ownership.

Key criteria deemed necessary to successfully mobilize capital include the recognition that programs and mechanisms must be of a sufficient scale and standardization to attract conventional equity and debt, and to minimize the demand on public-sector budgets; and that public funds should be used to reduce risk and leverage private investment.[78]

Clean Energy Finance Initiative

Beginning in 2014, the EAN continued its focus on financing by engaging the Coalition for Green Capital (CGC), along with a set of state agencies, to assess the needs and opportunities for increased clean energy financing in the state. A 501(c)(3) non-profit, the CGC is an advocate and advisor on the creation of public clean-energy finance authorities that use public-private partnerships for clean energy financing. In the context of limited public resources, these structures offer targeted financing of public dollars to leverage far greater private investment. Such techniques can preserve tax dollars, drive private investment, and enable citizens to access cheaper, cleaner, and more reliable energy with no upfront cost.

The CGC conducted interviews of key stakeholders, program managers, and policy makers around the state to analyze the financing needs and options in Vermont. It determined that the financing needs are significant: updated estimates are that more than $33 billion in capital, including what is currently available, will be needed to meet the state's goal of 90% renewables by 2050. To achieve this, the CGC's assessment found that Vermont needs new institutional capacity that can drive the required market transformation. Among its other observations: most programs offered by the state are grants, not

[77] Wasserman and Barton, p. 2

[78] Wasserman and Barton, pp. 5-6

financing; public dollars and programs are fragmented across agencies; no single entity has responsibility for market development; and some existing funding sources have major limits to expansion.

In its comments to the DPS for this CEP update, the CGC called for strategies to overcome institutional gaps and significant barriers to market growth that can be addressed through financing and optimized program design, including:

- Clear responsibility in the state for marketing financing, tailored to consumers' real needs;
- Clear ownership within the state for the management of combined energy analysis for whole-building solutions;
- Better alignment between state energy needs and the use of state funds;
- Coordinated engagement, and a government willingness to take the first dollar of risk to attract private investment; and
- Project aggregation, which is critical across markets to attract capital.

The CGC suggested that policy makers explore the experience of other states with clean energy financing, and consider the options.

6.5 Investments for Clean Energy Business Growth

Vermont's clean-energy industry continues to grow, with more than 16,000 workers identified. And although a large amount of capital is needed to finance clean energy projects, in this rapidly evolving landscape there is also continued need to make capital available for entrepreneurs with clean-energy technology and service businesses. Companies need financing to help with projects; they also need growth capital and support systems that can help them succeed.

Investment in small, clean-tech enterprises can be hard to come by, with services and products slow to reach market and businesses facing numerous risks along the way. Improving the prospects for growth among early stage and growth-oriented clean energy companies in Vermont is enhanced by access to risk capital. Venture capital firms fill this role, and improving the business practices of entrepreneurial companies provides a more robust foundation for venture firms to accelerate growth in Vermont with the prospect of additional growth outside of the state as they mature.

Here are examples of organizations that are working to overcome these challenges in Vermont:

VSJF Flexible Capital Fund, L3C
The Vermont Sustainable Jobs Fund’s Flexible Capital Fund provides risk capital to early-stage entrepreneurs, using an innovative royalty-finance model that allows for income and upside to the fund’s investors while preserving the ownership and mission of the founder entrepreneurs.[79] The fund provides

[79] Vermont Sustainable Jobs Fund, *Flexible Capital Fund*, www.vsjf.org/what-we-do/flexible-capital-fund

an important source of capital during critical growth stages to companies, including energy firms located in the state.

Vermont Center for Emerging Technologies

Emerging tech entrepreneurs needing assistance can turn to the Vermont Center for Emerging Technologies (VCET) for active coaching, education, co-working space, and potential investment from the Vermont Seed Capital Fund, a revolving $5 million venture capital fund for select high-opportunity businesses, including investments in clean energy in the state.[80]

Vermont Climate Change Economy Council

The Vermont Council on Rural Development convened a group of business, non-profit, and community leaders, elected officials, public policy advocates, students, and interested residents to frame policy and investment strategies for advancing development of the Vermont climate economy. Summit participants generated recommendations that covered a wide range of topics; these included formation of the Climate Change Economy Council, with a one-year mission to develop a structured plan with practical actions to reduce carbon emissions and stimulate green economic development in Vermont. Focus areas included seeding a climate investment strategy, spurring research and development for new technologies, and advancing the next stage in efficiency and conservation. The Climate Change Economy Council has convened throughout 2015 to develop a platform of actions.[81] The group anticipates releasing its recommendations in early 2016.

Vermont Low Income Trust for Electricity (VLITE)

Created out of the merger of Central Vermont Public Service and Green Mountain Power in 2012, VLITE is working with DPS, the Agency of Commerce & Community Development, and other energy stakeholders to further the state's energy policies. In addition to its grant making activities, VLITE is exploring activities such as a clean energy business accelerator that would assist entrepreneurs seeking early stage resources to create new ventures or grow existing companies in the state.

Such programs that support growth of businesses complement existing activities to expand the clean energy ecosystem and help advance toward the CEP goals.

6.6 Finance Tools and Policies

The markets for clean energy financing are evolving, as more organizations seek access to finance resources and more institutions offer products. A number of financing mechanisms are currently available in Vermont, and others are in development. Further evolution of clean energy markets will benefit from access to a diversity of finance options that are cash-flow positive or neutral, so that

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80 Vermont Center for Emerging Technologies, vermonttechnologies.com

81 Vermont Council on Rural Development, *Summit Report: Summit on Creating Prosperity and Opportunity Confronting Climate Change* (February 18, 2015), vtrural.org/programs/summits/2015-climate-economy-report, p. 3

customers can choose the financing mechanism most appropriate to their particular situation. Access to finance alone will not make it possible to achieve the CEP's goals; financing must be combined with marketing and other policy tools to drive the demand for these services.[82] However, insufficient access to affordable financing can dampen rates of investment in energy efficiency and renewable energy. Beyond access to tools, it is clear that the state will need focused leadership and integrated capacity to implement an effective set of strategies. This will require expanded efforts to engage the state's existing clean energy finance partners and institutions in new and creative approaches.

Below are summaries of finance products currently being used for energy efficiency and/or renewable energy projects. Some of these tools or resources, in addition to those previously detailed, may be expanded upon to increase the availability of affordable capital needed to achieve the goals set forth in this plan.

Financial Institution and Credit Enhanced Lending

Generally available through banks, credit unions, and mortgage companies, traditional financing is offered through equity-based loans (such as home equity loans, mortgages, or refinancing) or personal, unsecured loans. Both home equity and unsecured loan products for renewables and energy efficiency are available to customers now. Some Vermont financial institutions also offer energy loans with special features. (Exhibit 6-4)

As Vermont's economy emerges from the Great Recession, lenders are gradually easing restrictions while still limiting their risks, and making more loans. Generally, customers with good credit and the willingness to take on a loan will be approved. However, efforts to reduce credit risk for financial institutions — such as the Heat Saver Loan, PACE financing, NeighborWorks of Western Vermont Energy Loan, and CEDF-supported Solar Loans at VSECU (all of which include credit enhancements) — help borrowers with lower credit scores gain access to financing that reduces the upfront impact of investments in energy efficiency and/or renewable energy technology.

Traditional financing can also be offered through utility/efficiency provider partnerships with private lenders, as has occurred in Vermont Gas System's credit union financing program, offered to customers seeking VGS efficiency services. This program provides easy access to private financing for customers, and VGS guarantees lower-credit-score customers for the benefit of the credit union lender.

[82] Although low-cost finance products are essential to the success of renewable energy and energy efficiency activities in Vermont, so are other elements of a financing package. These include tax credits, tax deductions, rebates, energy policies such as the Standard Offer, development of standardized contracts, aggregation strategies such as Solarize that achieve local economies of scale to reduce purchasing prices for consumers, and others. Details of these elements are beyond the scope of this section, but remain key elements of successful financing.

Exhibit 6-4. Finance Products for Renewables/Energy Efficiency in Vermont

Financial Institution	Description
Brattleboro/Springfield Savings and Loan	Home equity and personal loans
KeyBank	Go Green Auto Loan
National Bank of Middlebury	Green Advantage energy improvement loan; finance provider for PACE
Northfield Savings Bank	Home equity and personal loans
People's United Bank	Home equity and personal loans
TD Bank	Home equity and personal loans
Union Bank	GreenLend for energy efficiency and renewables
Green Mountain Credit Union	Energy improvement loans for energy efficiency and renewables
Members Advantage Community Credit Union	Energy Loan Plus for energy efficiency and renewables
New England Federal Credit Union	Energy Smart Loan
Opportunities Credit Union	Reduced rate Heat Saver Loan for energy efficiency and select renewables
Vermont Federal Credit Union	Freedom Home Loan for energy efficiency
Vermont State Employees Credit Union	Reduced rate Heat Saver Loan for energy efficiency and select renewables; VGreen loans for energy efficiency and renewables; Windham Solar Loans; Community Solar Loans
NeighborWorks® Alliance of Vermont	Home Repair/Energy Loans via five regional member organizations

Note: This is a partial listing based on a sampling of financial institution websites.

On-Bill Tariffed Financing and On-Bill Repayment

On-bill tariffed financing, a kind of non-traditional financing that allows local utilities to recover the cost of efficiency improvements through charges tied to the meter instead of the customer, allows utility customers to install efficiency measures without up-front capital or debt obligations. Payment for efficiency measures in rental buildings can be attached to the building or building unit (and their tenants). The length of these loans can also be matched to the energy savings created by the efficiency measure, creating a positive cash flow for the customer.

The recent passage of Act 56 of 2015 includes energy transformation projects in Tier 3, through which retail electricity providers are required to achieve fossil fuel reductions. Utilities are currently investigating options that can be employed to meet this requirement, potentially coupled with on-bill tariffs or on-bill repayment mechanisms for cost recovery. The PSB has begun to plan for the implementation of Act 56. The topics for consideration include issues related to failure by a customer to repay an obligation, and access to a utility's bill by unrelated fuel dealers, renewable energy vendors, and energy efficiency contractors.

The state has an interest in creating and testing a variety of financing mechanisms that meet the different needs of energy customers. Along with anticipated development of on-bill tariffed financing, Vermont now has examples of on-bill repayment. For example, Green Mountain Power customers who obtain an energy loan from NeighborWorks of Western Vermont can opt to repay loans via their regular electricity bill. GMP customers can also make lease payments for heat pumps directly through their regular GMP utility bill. Customers of Burlington Electric Department also have access to an on-bill financing option for electric-energy efficiency improvements.

In addition, as previously described, the DPS is also working with Opportunities Credit Union and some fuel dealers on a new, on-bill repayment option that allows heating fuel customers who obtain a Heat Saver Loan to make payments via their fuel dealer's regular monthly bill. Having a viable fuel-bill repayment model would help provide coverage where a fuel dealer's territory cuts across multiple utility service territories, of which only a subset can opt to create an on-bill plan.

Property Assessed Clean Energy (PACE)

PACE was designed and created in 2009 by Act 45 to provide an alternative mechanism that would allow homeowners to finance their energy improvements by opting into a special assessment district created by their municipality. Efficiency improvements would then be funded by arrangement with a private financial institution, taxable municipal bonds, or other municipal debt. PACE financing is an assessment on the property, which in the event of default allows for collection of past-due payments via the municipality's property tax collection process. Communities may decide to run the program, or can elect to have Efficiency Vermont act as the program administrator, in which case payments can be billed monthly via a financial institution rather than via the property tax bill. This enables the town to offer PACE financing without the burden of billing and processing payments.

PACE was designed to overcome the up-front cost barrier to efficiency. In addition, it doesn't necessarily create a personal debt obligation: if the property is sold, the subsequent owner acquires both the efficiency improvements and the remaining payment obligation.

A State PACE Reserve Fund was created by the Vermont Legislature through Act 47 of 2011 (24 V.S.A. §3270) administered by the state treasurer. All municipalities in Vermont are encouraged to become PACE districts to facilitate this financing option. As of 2015, 35 towns have adopted PACE and 18 others are in the process.[83] To date there are seven completed projects, with two more in the construction phase. Efficiency Vermont is the administrator for PACE in Vermont.

Despite much effort, Vermont's PACE program has been slow to take off. The presence of other competing finance products makes it more difficult to find customers, and issues associated with verifying a clean title on the property and difficulties with underwriting continue to require attention.[84] To help spur participation, Efficiency Vermont conducted community forums and financing workshops in 2015, and waived the application fee. For a limited time, some applicants may qualify for an interest

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[83] For a list of current PACE towns and requirements, see www.efficiencyvermont.com/For-My-Home/Financing/Financing/PACE-Overview

[84] For PACE underwriting criteria and standards, see Banking Bulleting #34, Revised April2, 2012, www.dfr.vermont.gov/sites/default/files/BankBull_34_Revised_April_2012.pdf

rate buy-down (IRB).[85] In addition, the previous every-other month subscription period was changed to allow applications at any time; and interest rates for the IRB are now limited to $15,000 of eligible project measures, up from $10,000 per project.

Recently states have made progress implementing residential and commercial PACE programs. By the end of November, more than 57,000 residential PACE loans were made nationwide, totaling over $1.18 billion with 67% going to energy efficiency.[86] Although some homeowners are encountering difficulty selling properties with PACE assessments, the PACE market continues to advance.[87] Given the improvements with PACE in other jurisdictions, Vermont's experience suggests there may be some challenges with the PACE program that would benefit from review and revision.

Energy Service Companies/Public Purpose Energy Service Companies

Energy service performance contracting (ESPC) is a budget-neutral approach to making improvements that reduce a building's energy and water use and increase its operational efficiency. By partnering with an *energy service company* (ESCO), a facility owner can use an ESPC to pay for today's facility upgrades with tomorrow's energy savings — without tapping into capital budgets. State and local governments can either implement ESPC projects in their own facilities or support ESPC programs.[88]

ESCOs provide energy efficiency-related and other value-added services, and ESPC is a core part of their energy efficiency business. In a performance contract, the ESCO guarantees energy and/or dollar savings for the project, thereby linking ESCO compensation in some fashion to project performance.[89] ESCOs have operated in commercial markets since the 1970s. As of 2011, revenues in this sector totaled $5.3 billion, with about 85% of those coming from energy efficiency services.

One challenge with application of the ESPC model in Vermont is that ESPCs are generally used for projects valued at over $1 million. ESCOs typically work on larger-scale projects, to generate the economics needed to make the project viable. With its dearth of larger facilities, Vermont is limited in the number of projects suited to this tool. The Department of Buildings and General Services finished energy upgrades to the Waterbury State Office Complex in 2011 through a performance contract; however, the damage to the complex from Tropical Storm Irene compromised the benefits from those energy investments.

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[85] For details, see www.efficiencyvermont.com/For-My-Home/Financing/Financing/The-PACE-Process

[86] PACENation, *Residential and Commercial PACE Market Growth,* www.pacenation.us

[87] Wall Street Journal, *Clean Energy Loans Make Sales Messy,* November 7-8, 2015, p. A3

[88] U.S. Office of Energy Efficiency & Renewable Energy (EERE), *Energy Savings Performance Contracting,* energy.gov/eere/slsc/energy-savings-performance-contracting

[89] Larson, et al, *The U.S. ESCO Industry: Recent Trends, Current Size and Remaining Market Potential* (paper issued by American Council for an Energy-Efficient Economy [ACEEE], 2014), aceee.org/files/proceedings/2014/data/papers/3-319.pdf; ACEEE, *2014 ACEEE Summer Study on Energy Efficiency in Buildings*, aceee.org/conferences/2014/ssb

Vermont now hosts a *public purpose energy service company* (PPESCO) known as Commons Energy L3C, a wholly owned subsidiary of VEIC. A PPESCO is an integrated, comprehensive, total-energy solution to accomplishing deep savings on energy costs for owners of small- to mid-sized public-purpose buildings in multi-family affordable housing, education, health care, and municipalities without access to capital, technical skills, and implementation services.[90] This innovation provides the opportunity to apply the functionality of ESPC to underserved markets in Vermont. The PPESCO model was recommended by the Thermal Efficiency Task Force, particularly for providers of affordable multi-family housing. The task force reported that while providing the benefits of traditional ESCOs, a PPESCO would also fund all cost-effective measures rather than only those with the greatest return on investment; it would include renewables; and it would provide a long-term financing structure to enable cash flow-positive benefits to providers of affordable housing.[91]

Energy-Efficient Mortgages

An *energy-efficient mortgage* (EEM) is a mortgage that credits a home's energy efficiency in the mortgage itself. EEMs give borrowers the opportunity to finance cost-effective energy-saving measures as part of a single mortgage, and to stretch debt-to-income qualifying ratios on loans — thereby allowing borrowers to qualify for a larger loan amount and a better, more energy-efficient home. Conventional EEMs can be offered by lenders that sell their loans to Fannie Mae and Freddie Mac. Conventional EEMs increase the purchasing power of buying an energy-efficient home, by allowing the lender to increase the borrower's income by a dollar amount equal to the estimated energy savings. Both the Federal Housing Administration and the U.S. Department of Veterans Affairs offer EEMs.[92]

Net Metering Credit Purchase Agreements

A *net metering credit purchase agreement* is a financing structure that enables property owners or tenants, including state and local governments, to realize the benefits of renewable energy generation without having to own the equipment and pay the up-front capital cost. State and local officials can use these agreements to finance their own projects, and they can help fellow agencies and consumers understand their value and mechanics.

Under this form of agreement, the buyer — a property owner or tenant — enters into a long-term contract in which they agree to pay a predetermined rate for the value of the net metering credits delivered from a renewable energy asset. The length of the contract varies depending upon the type of energy improvement, but typically ranges from 10 to 20 years. The payment is typically fixed, or pegged to a floating index that is on par with or below the current electricity rate being charged by the local utility company. The renewable energy developer utilizes this contract to attract private investors who are

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90 Vermont Energy Investment Corporation, *How to Create and Build a Public-Purpose Energy Services Company,* www.ppescohowto.org/

91 TETF, p. 65

92 For details, see Energy Star: www.energystar.gov/index.cfm?c=mortgages.energy_efficient_mortgages

comfortable with the customer's ability to make payments over the term of the agreement. This enables investors to realize their target return on investment for providing the initial capital.

Individual investors determine the value of specific agreements, based on criteria ranging from the term, value of energy delivered, creditworthiness of the counterparty, and other contract details. If the net metering credit payments over the life of the contract, plus any other incentives, produce a desirable return on investment, investors will provide the up-front capital to finance the project.[93]

Lease Arrangements

Leasing energy-related improvements, especially the use of tax-exempt lease-purchase agreements for energy efficient equipment, is a common and cost-effective way for state and local governments — and commercial property owners — to finance upgrades and then use the energy savings to pay for the financing cost. Leases often have slightly higher rates than bond financing; but they are a faster, more flexible tool than many other options, including bond financing, and they are an important tool for public entities to finance improvements in their own buildings.

Leases are contracts that allow an entity to obtain the use of (or purchase) equipment or real estate. They are similar to long-term rental agreements where the lessee uses the equipment for a period of time in return for regular payments to a third party (lessor). Leases come with a purchase option that can be exercised at the end of the lease period.[94] Along with net metering credit purchase agreements, leases provide a means for individuals to access distributed power generation, such as solar PV, via third-party ownership. The recent entrance into the market of this finance mechanism has helped to spur substantial increases in solar deployment, in both the residential and commercial market segments.

Net metering credit purchase agreements and leases offer consumers a way to afford systems, such as rooftop solar, that have relatively high costs of installation and low cost of operation. In this model, a private firm will arrange financing, then install and maintain the system on a site provided by the consumer, who buys the output over some period of time. It is possible in some cases for the consumer to have payments that are less than the cost of the energy displaced. Some companies also allow the customer to purchase the system at the end of a lease term. Numerous companies are currently offering lease options and net metering credit purchase agreements for solar in Vermont.

Revolving Loan Funds

Revolving loan funds (RLFs) are pools of money from which loans can be made for clean energy projects. As loans are repaid, the capital is recycled into another project. Government-sponsored RLFs, which may have lower interest rates or longer terms, play an important role with organizations that cannot afford market-rate credit. RLFs can provide benefits to both borrowers and lenders: borrowers can benefit from favorable loan terms, and lenders can benefit from having greater security on their investments, especially if the loan fund is backed by a loan loss reserve fund.

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[93] Adapted from U.S. EERE, *Power Purchase Agreements*, energy.gov/eere/slsc/power-purchase-agreements

[94] U.S. EERE, *Leasing Arrangements*, energy.gov/eere/slsc/leasing-arrangements

Some RLFs are established as internal finance vehicles: these include the University of Vermont's Energy Revolving Fund ($13 million), the Middlebury College RLF ($1 million), and the Vermont State Colleges' Green RLF ($2 million). Others can be accessed by outside applicants. In 2013, Green Mountain Power established the Evergreen Revolving Fund for the former CVPS territory, as an initiative under the Community Energy and Efficiency Development (CEED) Fund.[95]

The state supports RLFs for energy upgrades through the State Resource Management Revolving Fund (SRMRF) and the State Energy Revolving Fund (SERF), managed by BGS. The SRMRF, formed in 2004 with $1.5 million of capital, is applicable for projects that have a minimum cost of $5,000. Agencies can use this as a funding mechanism for cost-effective energy projects. Repayment to the revolving fund ensures the continuation of the available funds for future projects.

Applications for this fund are received, reviewed, and monitored by BGS staff, and projects must show energy savings and a payback that is acceptable for the given technology to the BGS staff. The projects will also need to show savings sufficient to repay the revolving fund after the project's completion. The SERF, created in 2014 via Act 178, has an $8 million credit facility established by the state treasurer. This is available for the purpose of financing energy efficiency improvements and the use of renewable resources projected to generate a cost savings to the state.[96]

Until recently, the CEDF provided loans through its RLF for renewable energy projects. As of 2015, the CEDF was receiving payments from loans made previously, and reusing those funds for other program activities.

6.7 Challenges and Opportunities

Expanding the amount of clean energy in Vermont to achieve state energy goals is going to take a substantial amount of investment of time and financial resources. Numerous challenges and opportunities lie along the path. The challenges include:

- High upfront costs for renewable energy and energy efficiency investments;
- Low deal flow;
- Recent decreases in the price of fossil fuels;
- Limited understanding of the technical, financial, and market risks involved with financing and investing in clean energy in the state;
- Immature markets for the clean-energy investment needed to replenish capital resources;
- Lack of sufficient public resources needed to support new public/private financing mechanisms and institutional arrangements; and
- Patchy coverage by financial products in market segments across the state.

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[95] This program has been discontinued for 2016.

[96] Act 178 of 2014, Section 41

As the state marshals resources, these opportunities offer a silver lining:

- Transitioning from an incentive model to a combined incentive-plus-finance model will leverage substantial amounts of private capital to support new renewable and energy efficiency projects.
- Supporting investment in clean energy projects offers the prospect for a vibrant clean energy industry, with thousands of well-paying jobs.
- Replacing expenditures on fossil fuels, which largely leave the state, with local investments controlled by local, community investors and project owners will retain resources in the state's economy.
- As national clean energy financial markets evolve and mature, Vermont will be poised to participate as appropriate to the state's scale.

Strategies and Recommendations

Vermont has made considerable progress in advancing clean energy since the 2011 CEP was released. However, there are substantial hurdles, both within the state and in the broader finance and investment universe, that must be overcome to bring sufficient financial resources to bear. Some of the recent progress has been incremental, and some has been a change to the fundamentals of energy financing, with the introduction of new legislation and new finance programs for energy efficiency and renewables at small scales coupled with increased coordination between governmental and non-governmental actors. Over the next five years, the CEP puts forward the following strategies to advance finance for clean energy in the state, and recommends the following priorities for implementation.

Finance Sub-Goal — Increase the use of affordable financing to accelerate progress toward the 2050 goal of 90% renewable energy.

Strategy One: Building on existing initiatives and working with Vermont institutions and partners, convene a clean energy finance and investment collaborative with the leadership needed to expand clean energy financing and investment in Vermont.

Recommendations

(1) *Align existing clean energy/efficiency finance and investment programs to extend their reach, improve their effectiveness, close market gaps, and minimize program overlap.*

(2) *Build on prior activities to evaluate finance tools currently available that have potential to accelerate renewable energy and energy efficiency deployment (e.g., Heat Saver Loan, PACE, VEDA commercial loans, CEDF incentives, on-bill programs, etc.) and expand the use of those tools as appropriate.*

(3) *Propose and prioritize new finance and investment tools to advance clean energy projects and businesses that are consistent with Vermonters' diverse values and aspirations for the future of our communities.*

Strategy Two: Develop a suite of new finance and investment options on the scale necessary to provide affordable capital necessary to meet the state's energy and climate goals.

Recommendations

(1) Organize new pilot programs using identified, scalable finance and investment tools to obtain firsthand experience.

(2) Expand the number of companies offering renewable energy and energy efficiency technologies and services with financing options provided by a range of utilities, municipalities, organizations, and financial institutions.

(3) Evaluate the effectiveness of renewable energy and energy efficiency financing tools in meeting accessibility, volume, and acceleration metrics.

Strategy Three: Continue using established tools as part of successful financings.

Recommendations

(1) Focus on continual improvement of finance tools and mechanisms currently in use.

(2) Bridge funding to enable the Clean Energy Development Fund to provide incentives, grants, and credit enhancements to advance adoption of renewable technologies; continue supporting Efficiency Vermont's incentives for energy efficiency investments; and coordinate both sets of activities to meet near-term needs, acknowledging that stable long-term funding is expected, should proposed transmission projects come to fruition.

(3) Continue the state's leadership by example through continued investments in renewable energy systems and energy efficiency upgrades at state facilities.

(4) Support Office of the Treasurer, VEDA, and VFDA investments and financing for renewable energy and energy efficiency.

(5) Consider decoupling Vermont's existing energy business tax credit from the federal Investment Tax Credit and expanding the tax credit to a wider range of entities.

7 Heat for Buildings

7.1 Overview

Thermal Energy Use

Thermal energy use, or heat, in buildings accounts for approximately 30% of Vermont's total site energy consumption. This energy is largely provided by burning fossil fuels: fuel oil, kerosene, natural gas, and propane. Biomass (cordwood and pellets, and wood chips in some commercial applications) and bioheat (a blend of no. 2 heating oil and biodiesel) fuel a smaller portion of Vermont's thermal energy use. The residential sector accounts for 60% of Vermont's thermal fuel consumption, commercial 29%, and industrial 11%.[97]

Approximately 68 million gallons of heating oil are sold annually in Vermont for residential consumption. Propane, also called liquefied petroleum gas (LPG), is used in space heating, water heating, and cooking and is expected to continue its strong growth. Approximately 67 million gallons of propane are sold annually for residential consumption. Wood is widely used for residential heating: an estimated 50% of Vermont homes use it as a primary or secondary heat source. Wood heat has also increased in popularity in schools as a replacement for fuel oil, and pellet use has jumped as small commercial buildings convert to pellet boilers and many homes have added supplemental heat with pellet stoves.

Commercial enterprises primarily use heating oil and propane for space heating, as well as for air conditioning, refrigeration, cooking, and a wide variety of other purposes. These uses consume 24 million gallons of heating oil and 43 million gallons of propane each year.

Industrial enterprises typically use heating oil and propane for manufacturing, with few instances of its use for space heating. These industrial uses in Vermont annually use 21 million gallons of heating oil and 4 million gallons of propane.

This plan proposes a goal of reducing total energy consumption by one third from our current level by 2050 (through increased efficiency in energy production and use), and by 2025 obtaining 30% of the heat used in buildings and 25% in industry from renewable sources. This chapter discusses the strategies for achieving those goals, and the challenges involved.

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[97] U.S. Energy Information Administration

Thermal Energy Costs & Efficiency Energy Savings

In 2013, Vermonters paid over $500 million to import and use fossil-based heating fuels.[98] Most of this money left the Vermont economy. Although they have fallen since then, fossil fuel prices are expected to rise in the coming years, and those increases will affect both homes and businesses. Currently, on a Btu equivalent basis, liquid biofuels are more expensive than fossil fuels, but the predicted increases in fossil fuel-based prices create an opportunity for the adoption of substitute biofuels.

Although weather conditions have always been a factor in Vermont heating, the rise in volatile weather plays an important role in how buildings can be cost-effectively heated. Vermonters have a significant opportunity to save on their heating costs by weatherizing their homes and businesses. Among the benefits that comprehensive and rapid weatherization of Vermont's buildings can bring to homes and businesses are that Vermonters will be less vulnerable to volatility in the fuel market, and to the effects of dramatic weather fluctuations; more money will stay within the Vermont economy; and Vermonters will reap the health benefits of living and working in more comfortable and efficient buildings.

Investing in thermal efficiency improvements — primarily air sealing, insulation, and heating system replacements — can dramatically reduce a building's thermal fuel requirements while increasing its affordability. At current fuel prices, thermal efficiency investments in a building can bring significant savings, and the value of those savings will continue to increase as fuel prices rise. As each year passes in which investments in thermal efficiency are not made, cost burdens must be borne by individual Vermonters, businesses, and property owners, collectively burdening the Vermont economy as a whole.

A typical Vermont residence heated with no. 2 heating oil will spend between $1,500 and $2,200 annually to meet a winter heating load of between 80 and 100 MMBtu.[99] Average commercial building heating loads are somewhat larger, around 120 to 150 MMBtu, and annual fuel oil costs for businesses can be substantially higher. If cold-climate heat pumps are used as the primary source of residential heat, that same level of demand (80 to 100 MMBtu) can be met with about $1,200 to $2,000 in annual fuel costs ($300 to $650 of which might be spent on backup fossil-fuel heat sources).[100] Advanced wood stoves and central pellet systems are capable of serving this same heating load at annual fuel costs of $1,500 to $2,000. An investment in weatherization can further reduce annual heating fuel costs by $300 to $600, assuming a 20% to 30% reduction in heating load — and when done together with the replacement of heating equipment, this investment can also reduce overall system capacity needs.

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98 The residential sector spent $262 million on fuel oil, $54.2 million on natural gas, $203 million on propane, and $18 million on kerosene (U.S. EIA).

99 Calculation assumes a fuel oil price range of $2.50 to $3.00 per gallon.

100 Calculation assumes heat pump serves between 70% to 80% of heating load with a range in coefficient of performance from 2.4 to 3. Electricity price is assumed to be 15 to 17 cents per kilowatt-hour.

Efficiency Potential

Regulated industries have traditionally been the focus of state energy efficiency policy: cost-based regulated utilities traditionally offer more opportunity for meaningful policy interventions than unregulated industries. However, increases in unregulated fuel prices over the past 20 years and a greater recognition of the damages from greenhouse gas emissions has increased attention on the reduction in use of these fuels. Heating oil, propane, and kerosene are distinct from regulated utility fuels in that their costs are not shared among a defined and closed group of ratepayers.

High consumption levels of these fuels create challenges and opportunities for efficiency initiatives in the unregulated-fuels sector. To get an indication of the scope of fuel usage and the total efficiency savings available, the DPS completed a study in 2015 on the energy efficiency potential of oil, propane, kerosene, and wood. The study selected appropriate energy savings measures to determine the total, achievable, cost-effective potential energy savings in unregulated fuels.

Achievable cost-effective potential is defined as the potential for the realistic penetration of energy-efficient measures that are cost-effective[101] and could be acquired given aggressive funding levels. As shown in Exhibit 7-1, the total achievable cost-effective potential as a percentage of the forecast of fuel consumption by 2034 is 9.3% for petroleum products, and 3.3% for wood. Fuel oil accounts for most of the savings, because it is used more extensively throughout the state than the other fuels.

Exhibit 7-1. Energy Efficiency Achievable Cost-Effective Potential by Sector and Fuel Type (2016)

Sector	Petroleum	Wood
Residential	9.7%	3.8%
Commercial	8.8%	-1.3%
Total	***9.3%***	***3.3%***

NOTE: The Commercial Wood percentage is negative due to fuel switching to wood heat.[102]

The study projected that the public funding necessary to acquire these savings is significant: around $200 million over 10 years, or $20 million per year on average.[103] This figure does not include program participant costs, which add another $100 million to the overall investment over the next 10 years. Estimates are that these investments will provide net-present-value savings to Vermont of approximately $472 million. This estimate is conservative, because its considers the avoided cost of various fuels as projected in 2007, before the recent rise and fall in energy prices.

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[101] Defined by the Societal Test applied as directed in Public Service Board Dockets 5270 (Order of 4/16/90) and 5980 (Order of 9/30/99). Available at psb.vermont.gov/

[102] The reason commercial wood savings are negative is because the modeling allowed fuel switching into wood, and those fuel switching measures were cost-effective enough to actually increase wood consumption to levels that are greater than the baseline forecast.

[103] Assuming a 2% future rate of inflation.

Economic, Environmental, and Health Benefits from Reducing Thermal Energy Use

Fuel switching and weatherization not only saves Vermonters money; they also have broader economic benefits. For example, cordwood is supplied overwhelmingly from in-state suppliers, whose largest cost is local labor and transportation.[104] There are currently around 2,500 to 3,500 workers employed in Vermont's forestry and wood-products manufacturing industries. Historically, less than 2% of Vermont workers have found employment in this industry. A future in which as much as one-quarter of home heating demand is met with biomass sourced from Vermont forests would present far greater opportunities for employment, innovation, and profit in the harvesting, processing, and delivery of wood products.

Investment in thermal efficiency improvements also provides income-earning opportunities for workers and entrepreneurs in Vermont's growing building-performance industry. Anywhere from 35% to 50% of the cost of a typical building weatherization project can go to pay wages for locally hired construction labor. Currently, fewer than 15,000 workers are employed in the Vermont construction industry, down from a mid-2000s peak of more than 17,000.[105] According to data collected for the Vermont Clean Energy Industry Report, weatherization activities since then have helped to provide employment for several hundred construction industry workers, who would have otherwise lost their jobs as the housing investment boom deflated and the construction share of the labor force returned to its historical norm of around 7%.

Today around 1,000 homes are built in Vermont each year. A future in which each year potentially more than 10,000 homes are weatherized, and as many more are outfitted with heat pumps or wood heating systems, will present significant growth opportunities for employment, innovation, and profit in the construction and building-performance industries.

It is also important to note that thermal energy use is the second-largest contributor to Vermont's GHG emissions; therefore, curbing emissions will require significantly reducing fuel use in existing buildings. According to the National Trust for Historic Preservation, "the construction, operation, and demolition of buildings account for 48% of the United States' GHG emissions." Improving the efficiency of buildings is a critical component in addressing climate change — and retrofitting, reusing, and recycling older architecture and historically significant buildings can substantially reduce GHG emissions in Vermont.

Along with reducing energy use and expenditures and lowering GHG emissions, thermal efficiency improvements can also provide substantial health benefits. Building shell and ventilation improvements result in better indoor air quality and comfort levels, with benefits for respiratory and mental health, and reduced impacts of insufficient heating or cooling on health. Energy cost savings also provide indirect

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[104] This is not the case for wood pellets, which, except for two production plants, are supplied to Vermont retail customers by out-of-state producers. Thus, as for fuel oil, the local employment supported by purchases of pellets consists mostly of retail and distribution operations.

[105] Vermont Department of Labor, Federal Bureau of Labor Statistics

health benefits by improving housing affordability, thereby leaving more financial resources available for groceries, health care, and other health-related expenditures.

7.2 Challenges of Heating Vermont's Buildings and Achieving Comprehensive Thermal Efficiency

A variety of challenges are involved with heating buildings and achieving comprehensive thermal efficiency improvements in Vermont. One is the construction of a thermally efficient building shell, with the installation of an appropriately sized heating system to meet the demands of the structure. Life-cycle costs of heating system investments are important to ensure that long-term savings are met by the proper choice of efficient furnaces, boilers, and stoves. Hot water generation offers a number of challenges that stem from fuel availability, the anticipated amount of hot water demand, and the space available to install equipment. Initial capital investment costs and payback for the installed equipment are considerations as well.

In developing a comprehensive statewide thermal efficiency program, we need to address the barriers for customers; the needs of different types of consumers (including low- and moderate-income homeowners, commercial property owners, residential and commercial renters, and landlords); the different needs for retrofitting different types of buildings (including older buildings); and the need for robust financing opportunities and funding for incentives and programs. (The challenges listed here are described in the context of thermal efficiency; however, most apply equally to electric efficiency.) Specific tools, both existing and to be developed or expanded, are discussed starting in Section 7.4.

7.2.1 Challenge: Customer Barriers for Thermal Energy Efficiency

Despite significant cost-effective energy efficiency opportunities, consumers regularly under-invest in energy efficiency— or they don't invest at all. There are numerous customer barriers, many of which are summarized below.

Multiple Entities Delivering Efficiency Services

The fact that Vermont has many entities with significant experience in offering efficiency services puts the state in a good position to reduce building energy consumption and adequately serve consumers' needs. The diverse number of providers of thermal efficiency services and programs in Vermont is a strength of the current efficiency infrastructure, because it offers many opportunities for participants to enter into efficiency projects, and provides expertise throughout the state. But this proliferation can also cause confusion for both consumers and energy service providers.

Service providers may have a hard time knowing what assistance, incentives, and programs are available, and customers are unsure which organization to contact to get the ball rolling, what incentives are possible, and whether a better deal is available somewhere else. There's often an additional hassle if customers want to incorporate both renewable energy and energy efficiency into a project, as very few companies can currently address and/or coordinate both. If customers choose to prioritize installing a renewable energy system before completing all reasonable energy efficiency measures, they may also be paying for a bigger system than they would need if they first improved the energy efficiency of their building.

An additional complication is that there are typically separate funding sources for electric efficiency, thermal efficiency, and renewable energy programs — so customers may need to participate in multiple separate programs to address and then receive incentives for different types of measures and system installations. The range of options available, and the multiple entity interactions a customer must have to fully complete an efficiency project, requires stamina on the customer's part, may cause confusion, and can lead to customers abandoning projects.

Split Incentives

Split incentives refers to situations in which the benefits and costs of efficiency measures are divided, or believed to be divided, between two different market actors. For example, one situation that has long been a barrier to efficiency programs is when a tenant pays the energy bills but the landlord is responsible for building upgrades. The landlord may not be motivated to invest in the improvements, because he or she will not directly benefit from them; but for the renter, those improvements would directly affect the unit's affordability. Also, energy costs may not be disclosed up front to potential tenants, or if they are disclosed it may not be in a format that is easily comparable to other rental property options. That hinders the renter's ability to make an informed decision on choosing a particular rental property based on the *total* costs to live there, versus just a comparison of rent charged. About 29% of Vermont households (74,000 households) are renters.[106] About 47.5% of those are cost-burdened: they pay more than 30% of their household income for housing costs, including heating costs.[107]

A second split incentive develops when building owners are not sure that they will remain in the building long enough to earn a payback on their investment, and are unsure they will receive adequate compensation for an additional investment if they sell their building; so they choose not to invest. Finally, builders often do not occupy the buildings they construct, so they do not see a direct benefit from installing energy efficiency improvements. The short-term outlook of these market actors often works to the detriment of long-term efficiency investments.

Up-Front Costs and Financing Access and Aversion

Efficiency investments have up-front initial costs, with payback occurring over a number of years. Efficiency retrofits can be cost-effective over a period of time, and can provide the consumer with

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106 Vermont Thermal Efficiency Task Force, *Analysis and Recommendations: A Report to the Vermont Legislature — Meeting the Thermal Efficiency Goals for Vermont Buildings*, (January 2013)

107 Bowen National Research, *Vermont Housing Needs Assessment* (for Vt. Agency of Commerce & Community Development), (February 24, 2015)

additional health, safety, and comfort benefits — but many Vermonters simply cannot afford to make the up-front investment.

Market research conducted in 2012, in partnership with EVT, VGS, DPS, and the High Meadows Fund[108], revealed that those who had not participated in the Home Performance with Energy Star Program and the VGS Retrofit Program perceived the overall or upfront cost of energy efficiency improvements as the main barrier in completing efficiency upgrades. Survey respondents also said that a valuable program offering, to encourage participation, would be "confidence that estimated energy savings would be realized." This indicates that Vermonters often fear that investments in efficiency upgrades will not deliver the promised payback in cost savings. Some financing options currently exist (see Chapter 6, Energy Financing) — but consumers may not be able or willing to access the option that would be most advantageous for them, such as a long-term loan. The path to securing a loan can also be a barrier.

Lack of Information

Building owners often have a limited understanding of the connections between their energy use and potential building problems such as drafts, discomfort, air quality, and ice dams. In deciding whether to go forward with improvement projects, they also frequently do not realize or factor in the non-energy benefits that result from energy efficiency improvements, such as increased comfort and safety. Building owners are also often unsure about how to start the process of improving the efficiency of their building, and where to go to get objective information. If this information is too difficult to find or understand, building owners can get frustrated and give up. Some also view higher-cost energy audits as a barrier to starting the process towards energy efficiency upgrades. Yet receiving information — including a comprehensive roadmap to building energy improvements — is a crucial first step.

7.2.2 Challenge: Lack of Funding to Achieve Desired Thermal Efficiency Improvement Pace

Currently, no comprehensive funding source exists that is large enough to facilitate meeting the state's goals for building thermal efficiency. A variety of entities deliver thermal efficiency services and/or programs; these include the Vermont Weatherization Assistance Program (WAP) for low-income residents, EVT, NeighborWorks of Western Vermont, and Vermont Gas Systems. Many of the available thermal efficiency programs received direct dollars and/or an indirect boost from funding provided through the American Recovery and Reinvestment Act (ARRA). A total of approximately $34.5 million of ARRA funding was made available for energy efficiency retrofits during 2009-12.[109] This enabled a

[108] The market research was conducted as part of an evaluation of the Home Performance with Energy Star Program and the VGS Retrofit Program. High Meadows Fund, *Vermont Single-Family Retrofit Market — Market Research*, (February 2013). Available at http://www.highmeadowsfund.org/thermal-energy-efficiency

[109] This includes direct ARRA funding provided to the Weatherization Program and NeighborWorks of Western Vermont, plus DPS-directed SEP and EECBG ARRA funding to VHCB, public-serving institutions, the Vermont Fuel Efficiency Partnership, Vermont BGS, and schools and municipalities.

substantial increase in completed efficiency projects and workforce development. But now that those funds are spent, the number of completed building efficiency projects is decreasing.

Under current conditions, it would take the WAP more than 50 years to completely weatherize the homes of its targeted low-income population. Delaying weatherization for these Vermonters places more pressure on other public resources, such as the Low-Income Home Energy Assistance Program (LIHEAP).

For Vermont families not eligible for WAP, and for Vermont businesses, thermal efficiency offerings are constrained by funding structures and allocations for thermal efficiency. Moreover, the existing funding sources in Vermont that are directed to thermal efficiency — the Regional GHG Initiative [RGGI] and the New England Forward Capacity Market [FCM] — rely on auction revenues that are subject to annual fluctuations. Regulated thermal efficiency programs offered by Vermont Gas Systems are available only in its service territory, which is concentrated in the Lake Champlain region.

Meeting Vermont's thermal efficiency building goals will require a significantly increased level of investment. The Thermal Efficiency Task Force (TETF) report estimates that $1 billion of both public and private investment would be needed to fully implement the plan set forth in its report, and to meet the statutory building-efficiency goals by 2020. The TETF recommended numerous policy, program, and regulatory changes to achieve these goals. To expand the program infrastructure and incentives offered to motivate homeowners, property owners, and businesses to complete the targeted building efficiency improvements between 2013 and 2020, the task force estimated that about $267 million in new funding over a seven-year period would be needed (annual program funding was estimated to range from $27 million in 2014 to $39.6 million in 2020).

Although cash incentives have many advantages, including decreasing the up-front impact of an efficiency investment and grabbing the attention of customers, most of the investment made in efficiency will necessarily come from private capital. Thus, upfront incentives need to work in concert with appropriate financing options, to attract investment with the least possible public contribution. (See Chapter 6 for more information on financing efficiency.) The total public investment (current plus incremental) would leverage $687 million in private financing and investment, a leverage ratio of 1.9 to 1. It is clear that if Vermont is to make adequate progress on its thermal efficiency goals, a significant amount of both public and private investment will be needed to facilitate a significant increase in building energy efficiency.

7.2.3 Challenge: Insufficient Services for Low-Income Household Efficiency Improvements

As we begin to develop a more comprehensive statewide thermal efficiency program, it is crucial not to forget Vermont's most vulnerable citizens. Yet meeting our building efficiency goals will require a level of building-owner investment that the low-income population cannot provide without assistance. The state needs to determine the appropriate balance for making funding and financing opportunities available to low-income and non-low-income homeowners for energy efficiency improvements.

As heating fuel prices increase, the strain on low-income households grows. Energy costs typically make up a high percentage of low-income household budgets, because these residents tend to live in older, less efficient homes. Also, energy costs have increased at a much faster pace than the average wages for lower-income workers and retirement benefits for seniors.[110] Low-income households are often forced to choose between paying for energy costs or other essentials, such as groceries, and may find themselves unable to pay for heat in the coldest months.

Rising fuel prices are also a substantial risk to the affordability of the state's low-income multifamily housing portfolio. The energy efficiency of these buildings will need to be substantially upgraded if they are to remain cost-effective and available for subsidized low-income housing. As mentioned previously, for non-subsidized rental housing where tenants pay the energy bills, landlords may not be motivated to invest in efficiency improvements because they will not directly benefit from them. This is one reason it has been a challenge for efficiency programs (including the Weatherization Assistance Program) to motivate landlords of private rental properties to make energy efficiency improvements to their buildings.

An additional component of this challenge is that lower-income households are less able to access available capital and/or take on debt — many still cannot afford even low monthly payments. Although there have been recent attempts to provide subsidized financing for lower-income populations, such as the Heat Saver Loan program, as discussed in Chapter 6: Energy Financing, this will not be an option for all lower-income households.

Vermont has seen tremendous success with the state Weatherization Asssistance Program; but because of funding constraints, the program still serves only a very small percentage of the low-income population. In the 2014-15 program year, 1,042 housing units received energy efficiency services; yet almost 50,000 Vermont households are estimated to be eligible for weatherization services.[111] (See more information in the later section on Vermont's Weatherization Program.)

A comprehensive thermal efficiency program needs to address the considerable gap in energy efficiency services and funding available for low-income Vermonters who do not qualify for the current Weatherization Assistance Program.

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[110] Regulatory Assistance Project, *Affordable Heat: Whole-Building Efficiency Services for Vermont Families and Businesses* (June 2011)

[111] Estimate is based on 2010 Census.

7.2.4 Challenge: Implementing Efficiency in Older Buildings

Many of Vermont's buildings are old and have not been renovated or retrofitted in many years. In fact, approximately 76,800 Vermont homes — 30% of the total — were constructed before 1940.[112] Technology, materials, and best practices have changed since these structures were built. Owners can improve the energy efficiency of these older buildings; but as with any renovation process, this can seem a daunting and expensive task. Some older buildings have significant historical value, helping tell the story of Vermont's past through architecture and design— how buildings were used, communities developed, or times changed. The key to a successful efficiency retrofit is to understand and identify the character-defining features that tell the building's story and ensure they are preserved, and to understand the energy-efficient aspects of the historic building and how they function.

Improving a home for energy efficiency may result in the need for lead or asbestos abatement, or other code improvements. One challenge when implementing efficiency upgrades is the presence of vermiculite insulation with asbestos. (See www.asbestos.com/products for information on other materials that may contain asbestos, which may be encountered during energy efficiency work.) Almost all vermiculite insulation used in buildings between 1919 and 1990 contained asbestos,[113] which can cause significant health risks if it becomes airborne. Inhaling asbestos can cause cancer as well as other lung-impairing diseases.[114]

When vermiculite insulation is discovered in a building, due to uncertainties with testing it should be assumed to contain asbestos. If spot testing comes up negative, it does not mean a bag of insulation emptied in another area didn't contain asbestos. Vermiculite is costly[115] to remove and must be done by a certified asbestos abatement contractor. The Vermont Weatherization Assistance Program (WAP) for low-income households recently started a pilot program to address homes with vermiculite insulation. (Previously, any home where vermiculite was present was deferred from receiving weatherization services.) See the later section on Vermont's WAP for more information.

When developing strategies for upgrading the efficiency of Vermont's existing building stock, such as revisions to the energy codes, it is important to consider potential difficulties and limitations for older and historic buildings. For example, the new Vermont Residential and Commercial Standards require historically significant buildings to comply with the standards unless an exemption request is submitted to the State Historic Preservation Office (SHPO), demonstrating that compliance with a particular provision would threaten, degrade, or destroy the historic design, materials, or workmanship of the building.

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112 Eric Phaneuf, "Working Group on Building Energy Disclosure" (presentation to Vermont Association of Realtors, August 2011)

113 National Trust for Historic Preservation, *Energy Advice for Owners — Historic and Older Homes*, p. 24

114 Ibid

115 Costs range from $7,000-$12,000.

Additionally, the new Residential Energy Standard exempts existing ceiling, wall, or floor cavities exposed during renovations from meeting insulation R-value requirements, and instead just requires that the cavities be filled with insulation. This avoids setting an unrealistic expectation for upgrades in existing homes that may not have been originally constructed in a way that can easily be brought up to particular R-value thresholds. These are the type of considerations that need to be contemplated when developing strategies for improving efficiency in existing buildings.

7.2.5 Challenge: Fuel Choice and Technology Limitations

Vermont home and business owners are limited in the types of fuel they can choose to meet their energy needs, because of existing capital investments and limitations in delivery infrastructure. Energy consumption serves a variety of end uses in different types of processes and buildings; the choice of energy fuel and technology should match end-use application and space with the most efficient, renewable, affordable, stably priced option that fully serves the end use. For example, while wood stoves may adequately heat some homes, many commercial spaces require central forced hot air because of their size and the way they are configured. The forced hot air may be powered by an oil furnace or a gas furnace.

Once owners invest in equipment to heat a space or manufacture a good, they will generally use that equipment until the end of its life. Even if the fuel that powers that technology becomes more expensive or the price becomes volatile, making business planning difficult, the investment in equipment "locks" the user into a certain fuel type for the life of that equipment.

Although wood heating may be more affordable in any given year, or natural gas may offer substantial money and energy savings, most users do not have the flexibility to switch between fuels to heat spaces, cool spaces, or manufacture goods. Providing flexibility in fuel choice would require greater capital investment, but in some cases can yield substantial money and energy savings.

Current Investments in Petroleum Infrastructure

In Vermont, many homes and businesses are heated with petroleum products in part because of substantial investments in oil or propane furnaces or boilers. Many manufacturers, which require a great deal of heat energy to be available on demand, have invested in equipment powered by petroleum products. Only a small portion of the state is covered by pipeline-delivered natural gas, so many users do not have access to this option. In residential heating, 33% of homes are primarily heated with heating oil, 21% with propane, 12% with natural gas, 15% with woody biomass and the rest by other alternative fuels.[116] In commercial heating, the breakdown is 25% heating oil, 29% propane, 35% natural gas.[117]

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[116] U.S. EIA, Residential Sector Energy Consumption Estimates, 2013, www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_sum/html/sum_btu_res.html

[117] U.S. EIA, Commercial Sector Energy Consumption Estimates, 2013, www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_sum/html/sum_btu_com.html&sid=US

At a societal level, investment in petroleum infrastructure also hinders fuel choice. From funding highways over railways to zoning low-density suburbs, public policy at the local, state, and national levels has assumed continued, affordable access to petroleum products. As a result, billions of dollars nationally have been invested in public infrastructure and privately owned equipment that supports or relies on unregulated, petroleum-based fuels. Boosting access to renewable fuels, natural gas, and electric heating and cooling options will take substantial efforts on the part of national, state, local, and private stakeholders.

Petroleum fuels contribute substantially to climate change and to the air quality challenges that Vermont faces. The prices for petroleum products, while currently low, are more volatile than renewable fuels or regulated natural gas. Even the most efficient fuel-oil systems are only 92% efficient. Propane is generally more widely available, and it benefits from the same high-efficiency heating equipment as natural gas — but winter supplies can be constrained by heavy summertime usage in the agricultural sector, and this can lead to price volatility.

When demand for petroleum fuels is high, especially in winter for heating, prices tend to spike, which cuts into the bottom line for manufacturers that rely on these fuels. Moving away from petroleum products to more renewable, efficient, stably priced alternatives in building heating and manufacturing is a policy priority in Vermont, but will be difficult due to existing capital investments.

Tensions in Upfront Costs and Operating Costs in Fuel Choice

Builders match fuels and technologies to their end-use applications to make sure that energy needs are fully met. They also balance the cost of installing a system with the cost of operating it. Initial capital investment costs and payback for the installed equipment are another consideration.

One challenge in heating a building is the construction of a thermally efficient building shell, and the installation of an appropriately sized heating system to meet the structure's demands. The major components of an efficient building shell are sufficient insulation and minimizing the amount of air that escapes, while maintaining adequate ventilation to keep the building habitable. A well-constructed thermal envelope benefits both heating and cooling equipment usage. For heating systems, the challenge is to install an efficient system that will meet the maximum heat load required for a building yet not be oversized. Also, the more efficient a heating system, the more it costs to purchase. Generally, gas boilers and furnaces are more efficient than fuel oil. Water heating presents a number of challenges, stemming from fuel availability, size of anticipated hot water demand, and space to install equipment.

Limited Access to Natural Gas

Natural gas can provide a more efficient, less polluting, more stably priced alternative to petroleum fuels for some users — but many Vermont homes and businesses do not have access to it. Natural gas is relatively clean burning, it emits fewer greenhouse gases than other fossil fuels, and systems can reach as high as 98% efficiency. Where it is provided via pipeline, it is a regulated and stably priced fuel. Where provided via tanker truck, it is currently an unregulated fuel with market-driven price fluctuations.[118]

However, only a relatively small percentage of the state's population — 40,000 customers, in Chittenden and Franklin Counties — can access the current natural gas distribution network. Customers with large thermal fuel demands outside this region must use unregulated petroleum fuels to meet their requirements. Where possible, these customers should switch from unregulated petroleum products to renewables and biomass to meet their thermal needs. Biodiesel, wood, and renewable electric sources may meet the needs of some large commercial and industrial users; but because of the attributes of these fuels, they are not appropriate for all end use applications.

In instances where renewable fuels cannot meet the end use need, or are unaffordable, compressed or liquefied natural gas, delivered via tanker truck, may provide an economical opportunity to reduce GHG and other air emissions. Compressed and liquefied natural gas are newly available, unregulated fuels in the Vermont marketplace that may offer the benefit of long-term price stability, although their prices are not regulated by the state. In the long run, renewable natural gas from waste streams such as animal manure and landfills can be blended with fossil natural gas. Renewable natural gas is a renewable fuel source that could help Vermont meet its renewable energy targets.

In some cases, switching from propane or fuel oil to compressed natural gas would lower fuel costs, introduce price stability, and reduce greenhouse gas emissions without incurring major capital costs. However, as petroleum prices are currently low, this conversion may not be as cost-effective at this time for commercial and industrial thermal processes that use other fuel types. Also, some systems are difficult to convert to compressed natural gas, and others are outside the compressed natural gas delivery area. Additionally, in some cases the installation of equipment for the delivery and use of compressed or liquefied natural gas is not economically feasible. There may also be some processes that are not compatible with using compressed gas as a fuel source.

Limitations of Heat Pumps and Renewable Sources

Although moving toward renewable sources in building heat and manufacturing is a high priority for the state, renewable sources will not adequately meet the demands of some large industrial and commercial users. Particularly in manufacturing, few renewable sources can provide large amounts of heat energy, on demand, at an affordable and stable price. It is critical that energy needs for these users be met adequately — and providing access to a wide variety of fuel choices will allow them to select the most effective fuel for their particular application.

For space heating, some users may be able to transition to cold-climate air-source heat pumps. However, that technology has its own limitations and drawbacks, such as a current inability to meet maximum heat

[118] Vt. PSB, Docket Number 7866, Declaratory Ruling Re: Regulatory Status of NG Advantage LLC, October 2012, psb.vermont.gov/sites/psb/files/orders/2012/2012-10/7866%20Final.pdf

load demands during the extreme low temperatures that Vermont experiences. A study recently commissioned by the DPS is currently evaluating the effectiveness, cost, and efficiency of heat pumps in meeting needs for space heating and cooling as well as impacts to the electrical grid during both peak heating and cooling periods.

Health Impacts of Fuel Choice

Fuel choice also has important implications for health. Energy is critical to protecting the health of Vermonters who use energy in heating, air conditioning, and medical care. Some types of energy consumption also negatively affect health because they can worsen indoor and outdoor air quality, and can lead to climate change.

Both indoor and outdoor air quality are influenced by not only the choice of heating fuel but also by the equipment used, and any installed mitigation measures such as catalytic converters. For all fuels, choosing modern, efficient equipment with high standards for mitigation is important. Having access to fuel choice is important to protect vulnerable individuals who have special needs for cleaner-burning options due to health issues such as asthma.

Heating with biomass rather than fossil fuels may be beneficial for reducing long-term net greenhouse gas emissions, in turn reducing climate change and associated health impacts. At the same time, expanding wood energy usage in Vermont raises some air quality concerns, with potentially negative implications for public health. Biomass combustion tends to result in lower sulfur dioxide emissions than does fuel oil combustion, but it emits substantially more of certain other pollutants — including fine particulate matter (PM2.5), carbon monoxide, and polycyclic aromatic hydrocarbons compared to the combustion of oil and gas.

While recent state and federal regulations impose stricter limits on particulate matter emissions from wood boilers, it is important to consider the health effects of PM2.5 and other pollutants so that proper steps can be taken in promoting best practices to reduce the emissions of pollutants and minimize adverse health effects. Health effects related to PM2.5 include heart and lung impacts, and exacerbation of asthma and other respiratory conditions. Scientific evidence suggests that any increase in PM2.5 emissions, regardless of how high or low background PM2.5 levels currently are, will have a negative health impact. See the Biomass Section in Chapter 12 for additional information.

Electricity in particular provides services that are critical for health — including air conditioning, which is an effective mitigation option for reducing heat-related health impacts, especially for vulnerable individuals such as older adults or the chronically ill. As the climate warms, providing reliable ways to cool buildings will become more important to protect vulnerable individuals. Vermont should strive to provide critical building-cooling services while keeping peak electric demand as low as possible. Some strategies to address this issue are choosing the most efficient technologies possible, whether heat pumps or AC units; and employing passive cooling strategies such as shade, ventilation, cool roofs, urban forestry, and minimizing impervious surfaces.

7.3 Goals

Building Efficiency Goals

The following building efficiency goals were established in the 2007/2008 Vermont legislative session through Act 92 (10 V.S.A. § 581):

(1) To improve substantially the energy fitness of at least 20% of the state's housing stock by 2017 (more than 60,000 housing units), and 25% of the state's housing stock by 2020 (approximately 80,000 housing units).

(2) To reduce annual fuel needs and fuel bills by an average of 25% in the housing units served.

(3) To reduce total fossil fuel consumption across all buildings by an additional one-half percent each year, leading to a total reduction of 6% annually by 2017 and 10% annually by 2025.

(4) To save Vermont families and businesses a total of $1.5 billion on their fuel bills over the lifetimes of the improvements and measures installed between 2008 and 2017.

(5) To increase weatherization services to low-income Vermonters by expanding the number of units weatherized, or the scope of services provided, or both, as revenue becomes available in the Home Weatherization Assistance Fund.

Vermont has made some progress since the enactment of this law, but we are behind pace in achieving these goals. Energy efficiency was improved in just under 18,300 housing units as of 2014, leaving an additional 61,700 housing units (or 77% of the total) to complete by 2020. The PSB was directed in Act 89, passed in 2013, to establish annual interim goals starting in 2014 to meet the 2017 and 2020 building efficiency goals. In February 2014, the PSB issued an order establishing the following annual goals:

	2008-2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
# of units	17,000	8,864	10,512	11,402	12,224	6,666	6,666	6,666	80,000

Through 2013, 15,683 units were completed, well below the first interim goal. In 2014, 2,609 units were completed, again significantly short of the established goal.

Act 89 also required the PSB to monitor and select a methodology for tracking progress toward the building efficiency goals. The DPS formed a working group to make recommendations on how the tracking should be conducted. The group's recommendations included these:

- Projects from the Home Performance with Energy Star program, the VGS Home Retrofit program, the Weatherization Assistance Program, and the Vermont Fuel Efficiency Partnership (VFEP) program will be tracked to monitor progress toward the goals.

- Tracking and reporting will focus on the 25% average reduction in fuel use, and not on a reduction in fuel bills.[119]

- Fuel use reductions will be reported at the household unit level, for projects completed in the reporting year, using actual fuel usage data when available and reasonable estimates when fuel usage data is unavailable.[120]

- Project reporting will include incentive amounts, total project costs, and carbon emission reductions. Both comprehensive shell retrofits and equipment-only replacements will be reported, but only comprehensive projects will be counted toward the savings goals.[121]

- Programs will report the individual household unit fuel savings, including those achieving less than a 25% reduction, as well as the average fuel savings of units completed across the entire program. Progress toward meeting the goals will be determined based on the average achievement across all four efficiency programs.[122]

- The DPS will annually file project and program savings from the five program administrators with the PSB.

All the working group's recommendations were approved and adopted by the Board on April 23, 2015.

Completing the weatherization of the remaining 61,700 housing units will require a significant ramp-up of thermal efficiency programs and services, and of private investment. To meet the state's other building efficiency goals, an additional significant ramp-up of energy programming will need to be put in place for weatherization projects with commercial and industrial customers that use unregulated fuels. It is

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119 This is due to the difficulty in measuring fuel bill reductions given such factors as price volatility, uncertainty associated with predicting future fuel costs, and fuel switching. The working group further argued that a focus on fuel bill reduction might have the consequence of promoting the pursuit of near-term cost reductions instead of long-term energy savings.

120 The working group recommended that program administrators report the average fuel usage reduction for projects completed annually and not attempt to track projects that span multiple years, as not all program administrators have the ability to track projects over multiple years and would incur potentially significant costs to do so.

121 The working group contended that while equipment-only retrofits may achieve significant fuel savings (over 25% reduction), they do not appear to meet the statutory intent of comprehensive savings. Additionally, there are no reporting requirements for equipment installers to insure an accurate count of equipment-only retrofits completed outside of energy efficiency programs.

122 Under this approach, the number of housing units determined to be meeting the annual goal would include individual housing units with a 25% fuel reduction or greater, and any additional individual housing units with fuel reductions less than 25% that still result in an average reduction of 25% or greater across the four efficiency programs. The working group contends that the achievement of goals based on average fuel usage recognizes that completion of a comprehensive project may in some instances result in less than a 25% reduction, because the calculation of any net reduction depends on the cost of the efficiency measures and the existing building energy efficiency level.

important to note that these customers have had a relatively low number of efficiency services available to them to date.

"90% by 2050"-Related Targets

The definition of the 90% by 2050 target in the 2011 CEP did not directly include energy efficiency. The 2015 CEP has established a complementary goal of reducing total energy consumption by one third or more from our current level by 2050, through increased efficiency in energy production and use.

The 2025 goals for heat used in buildings and industry include 30% of heat from renewable sources in buildings and 25% in industry, recognizing that heat is distinct from other (almost entirely electric) end uses in both buildings and industry. An energy service goal, such as these heat goals, could include both electric and non-electric means of delivering that service.

One possible mix that the Department has estimated would likely meet the goals for renewable energy by sector includes these components:

- Buildings — 30% renewable:
    - Maintain electric use for purposes other than heat at current level (while the number and total size of buildings grow).
    - Improve the energy efficiency of building shells, so that the required heat delivered falls by 14% on average.
    - Use 35,000 cold-climate heat pumps (using an assumption that each displaces the equivalent of 350-400 gallons of heating oil per year, and the electricity serving the heat pump will be on the trajectory of 90% from renewable sources by 2050).[123]
    - Increase the use of renewable bio-derived fuels by 20%, though a mix of increased use of wood and liquid biofuels blended into heating oil. (If this were met only with wood it would imply a roughly 20% increase in the use of wood for heat; if met with liquid bioheat, it would imply the use of bio blends on average between 8% and 10%.)
- Industry — 25% renewable:
    - Increase electric use for purposes other than heat by 10% (while production grows by more than 10%).
    - Maintain the current demand for heat.
    - Increase use of renewable bio-derived fuels by 35%, though a mix of increased use of wood and increased use of liquid biofuels blended into heating oil. (If this were met only with wood it would imply a roughly 35% increase in the use of wood for heat; if met with liquid bioheat, it would imply the use of bio blends on average of between 8% and 10%.)

7.4 Strategies and Recommendations

This section discusses a suite of strategies, including programs, that have a goal of reducing demand for heating fuels and/or switching to renewable fuels, including building energy standards and an enhanced

[123] This may change, based on results from the year-long DPS study on the use of heat pumps in Vermont.

Weatherization Assistance Program that complements a statewide thermal efficiency program. The strategies should lead to a reduction in both energy expenditures and emissions.

As previously mentioned, demand-side management programs and policy considerations in Vermont have traditionally focused on utility (electricity and gas) resource decisions and investments. Until recently, residential energy efficiency programs targeted at unregulated fuels have been delivered via the Weatherization Assistance Program for income-eligible participants, and there has been little in the way of commercial unregulated fuel-efficiency programs, despite the significant opportunity that the sector presents. Building energy codes have increased, and will continue to increase, the baseline efficiency levels of newly constructed and substantially renovated homes and commercial buildings. Program incentives, and more recently low-interest loans and on-bill financing, have also spurred investment in energy efficiency among unregulated fuels. Although this chapter discusses thermal renewable energy and energy efficiency, the DPS believes all energy investments should be considered holistically.

7.4.1 Comprehensive Building Efficiency

Achieving the state's ambitious goals for energy efficiency and 90% renewable energy by 2050 will require an integrated approach and new policies for whole-building approaches, using simplified mechanisms that include easy access to incentives and financing. Service providers will need to amplify and increase their outreach using a range of approaches that engage building owners and support the completion of energy improvements in a simple, hassle-free manner. At the same time, coordination among the many stakeholders involved with efficiency delivery as well as renewable energy services and programs will need to be strengthened to meet the state's goals. Over time, a balance may need to be struck between comprehensive whole building projects and customers' desire to tackle projects in smaller, more affordable pieces.

7.4.1.1 A Whole-Building Approach

A whole-building approach looks at a building as a system, and recognizes the interaction of all its components. Currently, comprehensive state-funded electric efficiency programs are delivered through the state energy efficiency utilities (EEUs), which are Efficiency Vermont (EVT), Burlington Electric Department (BED), and Vermont Gas Systems (VGS). There are also separate program offerings for renewable energy systems.

EVT and BED focus primarily on electric savings, given that their mandate is to acquire electric resources and their main funding source is electric ratepayers. Although VGS was recently appointed by the PSB to serve as the natural-gas energy efficiency utility in its current service territory, it has been operating efficiency programs for many years. Despite the offerings of programs by these entities, there is still only a small amount of funding currently available for thermal measures. Yet thermal measures represent a majority of the energy savings opportunity in many buildings. The result is that much of the energy-saving potential remains unaddressed.

The state Weatherization Assistance Program (WAP) for low-income residents is one state energy efficiency program that has succeeded in a whole-building efficiency approach. (Detailed information on this program is included later, in the Weatherization Assistance Program section.) The WAP completes a whole-home assessment, determining what electric and thermal measures should be completed; it then utilizes EEU funding for the electric efficiency measures, and other funding for the thermal measures. For consumers, the process is seamless: they do not need to get involved in separate programs to determine how they will cover the costs of the improvements.

Additionally, the implementers of the WAP (the Community Action Partnership, or CAP, agencies) facilitate the completion of all work, including hiring subcontractors and selecting the products and equipment to be installed, thereby minimizing the burden and time investment for building owners. Although this model is unique because the program pays 100% of the costs for the efficiency measures, it does demonstrate how a whole-building approach for efficiency can be taken even when a variety of funding incentives and opportunities are utilized. The program will also be piloting a new initiative to install wood pellet stoves in residences that have recently received, or are in the process of receiving, weatherization services. Wood pellet stoves will be installed if the characteristics of the home and the clients meet certain criteria. The program will be evaluated through post-installation phone interviews, along with review of heating bills before and after one full heating season.

EVT also currently has a comprehensive home retrofit program, Home Performance with Energy Star, that utilizes a number of different market actors while minimizing the burden on the customer. EVT offers technical training and Building Performance Institute (BPI) certification to contractors interested in entering the energy efficiency field. Funding is used to support this contractor base, and to increase the demand for retrofit services through customer marketing, financing, and incentives. Certain multifamily, mixed-use, and municipal buildings also qualify. But because funding is limited for non-electric efficiency measures, this program is not able to serve as many buildings as will be needed to meet the Act 92 goals.

Additionally, in partnership with EVT and the Home Performance with Energy Star program, NeighborWorks of Western Vermont provides efficiency services to Rutland County residents. NeighborWorks has partnered with multiple organizations, including Green Mountain Power, EVT, local banks and colleges, local government and planning organizations, and community resident volunteers to carry out intensive marketing and awareness efforts, followed by a coordinated package of energy audits and recommendations, low-cost financing, incentives, and construction management services. This effort provides another example of cross-organization coordination and implementation to serve Vermont customers.

The diverse number of providers of thermal efficiency services and programs in Vermont is a strength of the current efficiency infrastructure: it offers numerous opportunities for participants to enter into an efficiency project, and it provides expertise throughout the state. But this proliferation can also cause confusion for consumers and energy service providers alike.

The Thermal Efficiency Task Force report made the following recommendations regarding collaboration and coordination among program implementers and service providers:

- *Build the industry.* Develop partnerships to encourage heating service companies, building performance contractors, and renewable energy installers to work together to provide customers with a comprehensive roadmap for improving their building energy use.
- *Leverage the existing home improvement market to promote comprehensive solutions.* Consumers could be making more effective, and cost-effective, decisions if energy service providers could be coordinated to "upsell" more energy efficiency services at the same time, particularly high-quality air-sealing.
- *Program implementers should offer recognition and benefits to service providers* that meet high standards for technical excellence and comprehensiveness.
- *Make it simple for consumers.* Implement a statewide clearinghouse for easy access to information on consumer-level energy improvements, and provide coordination across thermal efficiency programs and providers.

EVT has created an Efficiency Excellence Network (EEN) to encourage contractors to identify and promote energy efficiency equipment and opportunities in their work. EEN designation is given to participating residential and commercial contractors that meet additional EVT training requirements. EEN contractors are experts in discovering energy saving opportunities that help guide Vermonters to make effective energy saving improvements. Benefits for participating EEN contractors include promotion by EVT, marketing resources and materials, training and support, and leads and referrals.

All EEN fuel dealers receive training in home efficiency, to enable them to conduct home energy checkups and provide advice to customers looking for ways to reduce their heating bills. Additionally, full-service fuel dealers collaborate with energy efficiency contractors, who are qualified to provide more in-depth guidance on energy usage and to complete comprehensive home energy projects. All comprehensive projects completed through EEN contractors and EVT's programs are eligible for incentives from EVT.

Recommendations

(1) Improve thermal energy program's delivery so that from the consumer's point of view, a smooth, "one-stop" approach to energy projects occurs.

(2) Consider the best mix of funding, financing, and informational approaches to achieve the building efficiency goals established in statute and in this plan. Identify stable sources of public and private capital for the required funding and financing mechanisms. Consideration should be given to funding programs from sources tied to the impacted fuels. The funding and financing should be adequate to, and be designed to,

address the needs of both low-income and moderate-income populations, as well as to address barriers faced by those who do not need incentives but still need information or access to capital to make the right efficiency choices and be motivated into action.

(3) Ensure that qualified contractors and service providers are available throughout the state.

(4) Continue to work on coordination and partnerships between heating service companies, building performance contractors, and renewable energy installers to provide customers with a comprehensive roadmap for improving their building energy use.

7.4.1.2 Net-Zero Buildings

Net-zero buildings have zero net energy consumption — all their consumption needs are met through renewable energy systems and energy efficiency. The goal is to have a highly efficient building that meets its own energy needs with renewable technologies.

Different definitions are used for the term *net-zero buildings*. Sometimes buildings are defined as net-zero only if they have enough *on-site* renewable energy to equal or exceed their energy use. In other cases, buildings may be defined as net-zero if they allow for *off-site* renewable energy generation, or the purchase of renewable energy certificates. This is an important consideration when designing a program or goal for net-zero buildings: some sites will be less appropriate for some types of renewable energy systems, such as solar PV and wind. A challenge in allowing for off-site renewable energy is how to track and ensure that those resources are sufficient and will remain available in the future. For both definitions, it is important to ensure that the maximum efficiency is achieved first, to avoid the installation of oversized renewable energy systems (whether on- or off-site) to compensate for unnecessary energy usage.

The U.S. Department of Energy recently released a definition for a *zero energy building*: "an energy-efficient building where, on a source energy basis, the actual annual delivered energy is less than or equal to the on-site renewable exported energy."[124] This also applies to campuses, portfolios, and communities. DOE defines *on-site renewable energy* as "energy produced from renewable energy sources within the site boundary."[125] So wood or other biofuel harvested and used for generation within the site boundary (within the property lines) is considered on-site renewable energy. Wood or other biofuel/biomass *delivered* to the site is not considered part of the on-site renewable energy. Also, by using *source energy* in the definition, DOE is including the site energy plus "the energy consumed in the extraction, processing and transport of primary fuels such as coal, oil and natural gas; energy losses in thermal combustion in power generation plants; and energy losses in transmission and distribution to the building site."[126] DOE

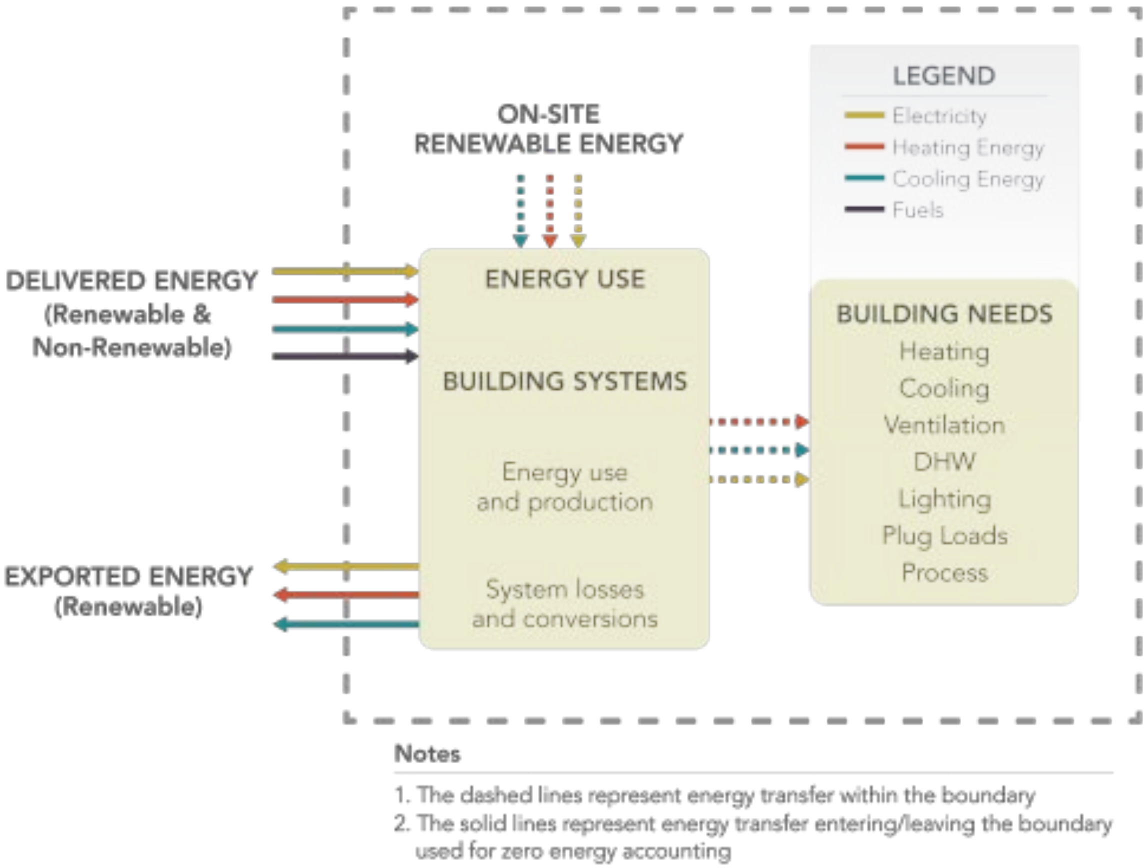
124 *A Common Definition for Zero Energy Buildings* (September 2015), http://energy.gov/eere/buildings/downloads/common-definition-zero-energy-buildings

125 Ibid

126 Ibid

uses national average source-site ratios for the conversion to source energy, so no building/campus/community is credited or penalized for the relative efficiency of any particular energy provider.[127] Exhibit 7-2 provides a visual demonstration of DOE's zero energy accounting in its definition.

Exhibit 7-2. Site Boundary of Energy Transfer for Zero Energy Accounting[128]



DOE also created a definition for a *Renewable Energy Certificate zero energy building*, for buildings "that have demonstrated through actual annual measurements that the delivered energy is less than or equal to the on-site renewable exported energy plus Renewable Energy Certificates."[129]

Another challenge in implementing a net-zero energy building strategy is the incremental cost. It has been estimated that there is an average incremental, or additional, cost of $40,000-$60,000 for net-zero

[127] Ibid

[128] Ibid

[129] Ibid

homes. [130] Efficiency Vermont's *Net Zero Energy Feasibility Study* estimated an increase of $31/square foot for a net-zero single-family home over a home that met the 2015 residential building energy standards.[131] According to the study, a single-family home built to code would cost about $120/square foot, and a net-zero home would cost $151/square foot.[132]

As an example, given these costs, a 2,000-square-foot home built to code would cost about $240,000, and a net-zero home would cost about $302,000, an increase of $62,000. The study also points out that "when additional energy efficiency capital costs and photovoltaics are financed … net zero ready and net zero residential buildings are cheaper to own and operate … than code buildings."[133] The study also includes an analysis of the costs for net-zero and net-zero-ready office and office/manufacturing buildings. All were shown to cost less than a code building to own and operate, when including currently available incentives and tax credits.[134]

Considerations for Vermont when pursuing a net-zero building strategy might include determining whether it's appropriate for manufacturing and processing or other building types, whether a net-zero strategy should be considered for existing buildings, whether any conditions should be put on the type or source of the renewable energy (such as biomass from sustainably managed local sources), whether biomass should only be considered part of the on-site generation if it is harvested on-site (as in the new DOE definition), and the health and durability of these buildings over a longer period of time.

Several states have developed or are considering developing goals for building net-zero homes. California has a goal to build all new residential homes to net-zero design by 2020, and all new commercial buildings by 2030. A report from the Massachusetts Zero Net Energy Buildings Task Force suggests a goal for all new residential and commercial buildings to achieve net-zero energy use by 2030 through incentives, minimum energy performance standards, and workforce development.[135] In 2014, the Massachusetts Pathways to Zero Grant Program was created to offer grants for construction of net-zero buildings. Massachusetts's proposed model may fit well here in Vermont.

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[130] Richard Faesy presentation, "The Vermont Comprehensive Energy Plan to Include Net-Zero Energy by 2030," June 2011

[131] *Net Zero Energy Feasibility Study* (January 2015), www.efficiencyvermont.com/About-Us/White-Papers/whitepapers/2015/03/12/net-zero-energy-feasibility-study

[132] Ibid

[133] This assumes a 30-year fixed mortgage rate of 4% and fuel escalation of 5% per year. The analysis did not include rebates, tax credits, or incentives for residential net zero energy construction.

[134] The analysis assumed variable loan interest rates over 20 years, a $13,000 EVT incentive for office buildings and a $27,000 incentive for the office/manufacturing buildings along with the 30% federal tax credit for PV, and reduced finance interest with a SBA loan.

[135] *Getting to Zero: Final Report of the Massachusetts Zero Net Energy Buildings Task Force* (March 2009), www.mass.gov/eea/docs/eea/press/publications/zneb-taskforce-report.pdf

Recommendations

(1) Consider and address the potential challenges for net-zero buildings in Vermont and complete recommendations for a clear path to achieve a goal of having all new buildings built to net-zero design by 2030. These recommendations should include the mechanisms that must be instituted to achieve such a goal (such as regulatory codes, energy codes, financing and incentives, and workforce training). The DPS will work with stakeholders to develop these recommendations.

(2) Investigate what mechanisms are necessary to achieve the goal of building 60% of all new homes in Vermont to Energy Star standards or the Efficiency Vermont Certified — Base Level[136] and broader market penetration of net-zero energy buildings, with a goal of having 30% built to net-zero design standards by 2020 as an interim target on the way to 100% net-zero buildings by 2030. This initiative will be led by the DPS and include the state EEUs as well as other stakeholders.

7.4.2 Opportunities in Fuel Choice and Technology

As discussed in the Fuel Choice and Technology Limitations section of this chapter, Vermonters do not have the flexibility to switch between fuels to respond to changing prices or environmental performance objectives, because of existing capital investments and limitations to infrastructure.

To respond to this challenge and improve access to fuel choice, the state plans to encourage use of the most efficient, renewable, cost-effective technology that will meet users' end needs. This includes implementing rigorous building standards in new construction, reducing heat loss in existing construction, and encouraging the adoption of renewable fuels in building heat and cooling as well as in industrial processes.

Specifically, this plan assumes the deployment of 35,000 cold-climate heat pumps by 2025; improving access to renewable bioenergy; investing in thermal performance and efficiency; and, where fossil fuels are still necessary, moving users away from petroleum to natural gas. In applications where wood or sustainable biofuels are not appropriate and pipeline gas is not available or planned, compressed natural gas transported via tanker truck may offer economic and environmental advantages for large commercial, institutional, and industrial users.

Builders and building managers must balance a variety of objectives and limitations when making capital investment and design decisions that affect fuel type. For all fuel types, builders and building managers should, when possible, choose the most efficient system to deliver heating and cooling. In most cases, a life-cycle cost analysis will point to the most efficient system. However, short-term decision-making may

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[136] To receive "Efficiency Vermont Certified" base-level incentives, buildings must meet the Vermont residential building energy standard plus the following: pass pre-drywall inspection, have air leakage of ≤3 ACH50, and have heating and cooling systems that meet Energy Star or equivalent standards. All major appliances must be Energy Star rated, and 80% of the fixtures must be Energy Star rated. An Efficiency Vermont Certified — High Performance Level is also available for incentives. These are basically net zero-ready homes.

suggest a less efficient system. Policies that encourage the communication of long-term energy costs will lead to developers being able to decide on efficiency. When non-market factors, such as environmental damages, are important in making the decision for more efficient heating systems, state policy decisions, including incentives and regulation, are appropriate.

7.4.2.1 Residential Fuel Choice and Technologies

In the residential sector, expanding fuel choice means increasing homeowners' access to technologies that allow the use of renewable energy sources, decreasing dependence on non-renewable energy sources, and increasing the overall thermal efficiency of building shells and heating systems.

In new construction, improved building codes and voluntary stretch building codes are an effective leverage point for ensuring efficiency and providing fuel choice. For example, a well-insulated building with passive heating and cooling measures, a heat pump, and backup efficient modern wood heating will provide a variety of options for homeowners. This example illustrates how homeowners should be able to meet their energy needs by flexing between passive, electric, and wood sources for heat and cooling depending on their needs, price, the weather, and other factors.

New construction should take advantage of technologies such as heat pumps, both ground- and air-source, and biomass pellet systems to decrease overall energy use. When coupled with efficient construction and renewable generation, these buildings can be highly cost-effective to operate.

Improving access to fuel choice in existing residential structures is a particular challenge due to the age and condition of Vermont's housing stock. As heating and cooling systems reach the end of their useful life, homeowners should choose to replace systems with the most efficient and renewable system available. These systems — for example, a well-insulated house heated with a pellet stove and thermal storage — are generally more expensive up front but less expensive to operate, so they often have lower total lifetime costs. Another major leverage point for existing homes is improved disclosure about energy performance at the time of sale.

For existing homes, the timing of intervention is particularly important. Incentive programs must reach homeowners at the time they are considering a replacement for their system or major renovations. When retrofitting buildings, contractors should conduct an energy audit and determine where best to save energy; in some cases that may be through a combination of thermal shell improvements and replacing outdated HVAC equipment. Cost drives decisions about retrofitting, so improvements may need to be spaced out over several years, depending on financing. In these cases, thermal shell improvements should be carried out first if possible, as these improvements will help reduce the overall heating as well as cooling loads for the building. Improving access and terms of financing for energy-related renovations is an important component of the state's strategy for fuel choice in existing homes. See Chapter 6 for more details about the state's plan for energy financing.

Builders and homeowners should strive to select technologies that, first and foremost, meet their end use objectives, but also take into account environmental performance and renewability. The following are recommendations specific to particular types of fuel.

Biomass (Pellet): Pellet systems should be installed with a minimum peak efficiency of 85% (on an HHV basis), and wood chip and cordwood systems with a minimum peak efficiency of 75% (on an HHV basis). These systems can heat space only or include a hot water system. Thermal storage for pellet hydronic systems is encouraged as best practice, but is not always essential.

Air-Source Heat Pumps: These systems use electricity to transfer thermal energy from the outside air into a home; or, in the case of cooling, to remove it from a home. Heat pumps have the potential to meet most of a home's thermal demands. The seasonal heating performance factor is approximately 240%; however, the time-specific efficiency varies due to temperature, and could drop to as low as 80% in extreme cold. The costs for these systems range for $3,000 to $12,000, installed, depending on the chosen system and number of internal heads if it is a multi-head system. The DPS is conducting a study to evaluate this technology and assess its advantages, limitations, and best practices when used in Vermont.

Ground-Source Heat Pumps: These systems rely on the same thermodynamic principles as air-source heat pumps, but take thermal heating and cooling energy from the ground, which maintains a steady average year-round temperature in comparison to outside air. As a result, these systems maintain a high level of efficiency year-round. These are extremely efficient systems for heating a building and will operate in all the extremes of Vermont's weather. Ground-source heat pumps are designed to link to central heat distribution systems much as furnaces do; but they provide a lower-temperature heat, so they work best with forced air or radiant heat. The system requires significant upfront capital investment, either to install the requisite closed-loop piping or for drilling several additional wells to provide the water the system needs to operate. These systems cost $15,000 to $25,000 to install, but have a long operational lifetime and maintain efficiency even in low temperatures.

Natural Gas/Propane: Builders and homeowners should choose high-efficiency condensing boilers or furnaces that range between 96% and 98% efficient. These condensing boilers can include on-demand hot water or a thermal storage tank.

Fuel Oil: Systems with efficiencies of 87% or higher for efficient boilers and furnaces should be chosen. These systems should include thermal storage for hot water, and should be placed to minimize hot-water pipe length to reduce heat loss in pipes to the areas of highest hot water usage.

Heat Storage: Any combustion system may benefit when linked to heat storage. Heat storage allows for a smaller combustion system by heating the storage medium (usually water) to a higher temperature when the heat demand is low, and using that stored heat when heating demand is high by circulating the stored heat through the distribution system.

7.4.2.2 Commercial and Industrial Fuel Choice and Technologies

Providing adequate and renewable energy for commercial and industrial thermal processes and building heat and cooling is a particular challenge in Vermont. Because commercial and industrial energy use represents 40% of the state total, conducting efficiency improvements and developing renewable alternatives in commercial and industrial applications is critical to meeting the state’s 90% renewable by 2050 goal.

Large commercial and industrial users should consider a range of renewable options to meet their needs. First and foremost, commercial and industrial managers should improve the overall efficiency of thermal processes, to lower consumption of fuels while still providing the same thermal energy performance on demand. To meet the remaining thermal load, managers should consider switching to biomass such as wood chips, pellets, and/or biodiesel to provide space heating, hot water, and power for industrial processes. Another option that managers should consider is installing heat pumps to provide space heating and cooling, coupled with net metered generation to offset some of the increased electric use.

Finally, in some cases, the strategic and efficient use of compressed natural gas transported via tanker truck may be the most environmentally and economically appropriate choice in some areas of the state, if biomass or renewables cannot be cost effectively deployed in a facility, and if natural gas pipeline infrastructure is not available or planned in that region.

Developing renewable natural gas, which can generate large amounts of heat on demand, may offer one path toward renewable alternatives in this sector. The state may have a significant role to play in fostering the development of renewable natural gas.

For non-renewable fuels, the thermal potential study identified measures for each non-renewable fuel source. Large thermal-process heat requirements are best served through a combination of fuel switching, where appropriate, and either the installation and commissioning of high-efficiency boilers and furnaces or the *retro-commissioning* (see the next page) of existing boilers and furnaces.

Stack heat recovery: Fuel use and cost should be reduced by recovering heat from flue gases with a stack economizer. This recovered heat can be used to preheat boiler feedwater or ventilation intake air, to reduce heating requirements. These systems can reduce heat lost through the stack by up to 80%, increasing the system's overall efficiency.

Integrated building design: This design approach is also referred to as *organic design* and treats the building as a whole instead of individual components, increasing operational efficiency. This approach has little impact on first costs of construction and can significant lower lifetime building operating costs by 20% or more, depending on the building's use. This approach does increase design costs, but these are generally offset within a few years of the building's operations.

High-efficiency boilers/furnaces: With the wide range of thermal needs in the commercial and industrial sector, high-efficiency boilers and furnaces are recommended for their better energy conversion to reduce overall fuel use. Efficiencies of this equipment can range from 85% to 98%, depending on application.

Retro-commissioning: This involves recommissioning or "tuning" existing equipment to increase efficiency. Over time, all combustion equipment loses efficiency through minor faults that develop even with well-considered maintenance plans. This approach allows existing equipment to be brought back to near peak operating efficiency for a relatively low cost. However, thought should be given to replacing aging equipment when it is cost-effective to do so.

Fuel switching: Both DPS studies of fuel efficiency savings identified a number of cross-cutting fuel-switching recommendations. These included switching to biomass heating for space heating, and switching to heat pump water heaters and solar hot water to offset non-renewable fuel use.

Commercial heat pump water heaters: This is primarily a fuel-switching measure. Where a hot water demand can be met with a commercial-scale heat pump as opposed to a fossil fuel boiler, this measure should be considered. Care should be taken to review the hot water demand requirements, to make sure the heat pump can recover quickly enough to meet the demand.

Improving fuel choice for commercial and industrial users has many economic and environmental benefits. Most of these processes currently rely on fossil fuels, especially petroleum fuels. Although petroleum products are competitively priced at present, short-term price spikes in winter, as well as longer-term upward trends, create an economic drag on commercial and industrial sectors. The environmental performance of these fuels is also a concern. Many industrial processes require large amounts of energy delivered on demand, which can be difficult to provide using renewable energy sources.

<u>High-Efficiency Boilers/Furnaces for Industry (Process Heat)</u>

Energy efficiency for industrial boilers is highly boiler-specific. Four factors are critical for assessing energy efficiency in industrial boilers/furnaces: fuel type, combustion system limitations, equipment design, and the type of load being served.

Recommendation

Expand EEU support for cost-effective measures for industry to transfer from traditional unregulated fuels such as heating oil and propane to renewables such as biofuels and biomass and, if necessary, compressed natural gas. Provide recommendations and potential incentives to promote this move.

7.4.2.3 District Heat/Energy Systems

District heat allows residential, commercial, and institutional users in relatively dense towns to be supplied with heating and cooling energy, and sometimes also power (in the case of a district energy system), via underground energy distribution systems. Connection to a district heat network removes the need for individual boilers, potentially chillers, and plant rooms. A range of fossil and renewable fuel-based generating plants can be used to supply the system. These can incorporate combined heat and power systems, thermal storage, and heat pumps to maximize the efficiency of the unit's ability to meet both heating and cooling demands along with part of electric demand. These systems can be run cost-effectively on biomass, and in some cases on domestic household waste. To be cost-effective, they require sufficient demand and user density, to spread the cost of the distribution system. These systems are scalable and can be cost-effective for as few as 20 homes — but as noted above, their cost-effectiveness is directly proportional to the length and difficulty of installing the insulated piping required to deliver the thermal energy.

In Montpelier, a new district heating plant provided reliable, cost-effective heat to over 20 buildings during the 2015 winter heating season, with expansion planned for future years. The project was financed with bond money and public funding, including support from the DPS.

More information on district heating systems can be found in Chapter 13.

Recommendation

Identify the potential challenges for district energy systems in Vermont and complete recommendations for a clear method to identify potential communities for the deployment of this technology and how to address the first cost capital costs of construction. These recommendations should include the mechanisms that must be instituted to achieve such a goal (such as regulatory codes, energy codes, financing and incentives, and workforce training). The DPS should work with stakeholders to develop these recommendations.

7.4.2.4 Combined Heat and Power

Combined heat and power[137] (CHP) technology centers on the recovery of otherwise-wasted thermal energy to produce useful thermal energy or electricity. Roughly 65% of fuel energy content that enters a conventional electricity generating station is released as waste heat. CHP systems use most of this heat, increasing total system efficiency to 80% or higher.

CHP's higher efficiency comes from recovering the heat normally lost in power generation or industrial processes to provide heating or cooling on site, or to generate additional electricity. CHP's inherent higher efficiency, and its elimination of transmission and distribution losses from the central power plant, results in reduced primary energy use and lower greenhouse gas emissions. More than 85% of all

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[137] www3.epa.gov/chp/documents/faq.pdf

generating capacity sited at industrial and commercial facilities uses CHP technology. In Vermont, these applications are generally primarily used to provide the initial thermal load, with electrical generation being secondary. This is referred to as a *bottoming cycle* system.

Industrial applications with constant thermal and electric demand are ideal candidates for CHP. In the industrial sector, CHP is most likely to be found in energy-intensive manufacturing. In the commercial sector, CHP is often used for building heating and air conditioning, at college campuses and hospitals.

An example of CHP can be found at North Country Hospital,[138] where a wood chip biomass CHP is used to heat and cool hospital buildings and run the building's refrigeration systems, as well as meeting some of the hospital's electrical power consumption.

CHP systems operate with a wide range of fuels. In Vermont, the most common type of CHP system is wood chip biomass; but with the availability of compressed natural gas, industrial and commercial users now have an additional option for implementing CHP, and for accessing the comparatively low prices and price stability that natural gas offers, if biomass is not suitable for their specific thermal and electrical needs.

In general, all electricity generated by a CHP is considered *behind the meter* and is used directly; however, there are opportunities to net meter these systems. Renewable systems are capped at 500 kW, while non-renewable generation is capped at 20 kW.

Recommendation

Identify the barriers for biomass CHP systems in Vermont and provide recommendations for a clear method for the deployment of this technology and how to address the upfront capital costs of construction.

7.4.3 Outreach/Consumer Information

A lack of effectively targeted information is a market barrier to energy efficiency improvements in Vermont. Efficiency programs must convey how efficiency translates into dollars saved in participants' pockets, along with describing its economic benefits for the entire state.

It is important for the whole-building approach discussed in this chapter to have integrated and targeted outreach that reaches customers at points where they will listen. Case studies of completed projects should be made available, covering all building types and involving customers of all economic and social segments of the population. (VEIC has released three case studies, and NeighborWorks of Western Vermont has used targeted marketing to aid in its customer service efforts; these types of communications should be continued.) Best practices must be shared across energy service providers in Vermont, to transform markets and facilitate replication. Websites must be easy to navigate and contain

[138] www.nrbp.org/publications/biomass-chp/appendixa.pdf

both the basic and in-depth information that building owners are seeking. Perhaps most important, multiple actors in the marketplace must convey a clear, singular, overarching message.

Marketing and outreach as programs are delivered is vital. Town energy committees are growing in number across Vermont, and are becoming a pivotal point for providing this type of outreach within communities, and for further developing community-based projects and programs. Ensuring that such committees continue to thrive, and their number expands to more towns throughout Vermont, will help to advance grassroots energy efficiency and conservation efforts. Among other initiatives, energy inventories and "challenge" initiatives should be encouraged, and their successes should be widely reported.

7.4.3.1 Thermal Energy Clearinghouse

Act 89, which was passed in 2013, directed the Public Service Board to establish a statewide information clearinghouse, enabling effective access for customers and coordination across thermal efficiency programs, per the recommendation in the TETF report. The clearinghouse is intended to serve as a portal for customers to access thermal energy efficiency services, and for coordination among state, regional, and local entities involved in the planning or delivery of such services.

In response to Act 89, the PSB opened a proceeding to establish a thermal energy statewide information clearinghouse, and issued an Order that established its framework, including a web-based portal to enable access to clearinghouse information and the development and distribution of clearinghouse promotional materials. The Order required the DPS to issue a request for proposals (RFP) for expert assistance and technical services necessary to develop the thermal energy clearinghouse.

The DPS issued an RFP, which required applicants to provide a budget that included the costs for the development of a clearinghouse website and promotional materials, and any ongoing promotional and distribution-related costs. The RFP also specified that the clearinghouse web-based portal include at least:

- A directory of materials about thermal energy efficiency and thermal renewable energy services and resources;
- Direct links to qualified service providers; and
- Information/links regarding associated environmental issues.

While the focus of the clearinghouse is thermal energy efficiency, it will also include thermal renewable energy as part of a comprehensive building approach, in tandem with efficiency, to achieve the state’s building efficiency goals.

Other clearinghouse functions will include enabling effective access for residential and commercial customers; coordination across programs; serving as a portal for customers to access services; coordination among state, regional, and local entities involved in the planning or delivery of such services; and making referrals as appropriate to service providers, and to entities that can provide information on related environmental issues.

Other objectives for the clearinghouse include:

- Meet consumers of all types, whether residential or commercial, at the point where they are in the spectrum of thermal energy awareness and investment, and connect them with appropriate programs and services.
- Guide next steps and identify available and appropriate technical and financial assistance.
- Enable effective coordination across programs.
- Enable partners, contractors, and customers to keep track of all available rebates, incentives, financing options, and other program services.

To serve its function and achieve these objectives, the clearinghouse will include at least a directory of materials, links, and referrals regarding thermal energy and thermal renewable energy resources, services, service providers, and entities with information about related environmental issues. The clearinghouse should also elevate consumers' general knowledge about thermal efficiency and thermal renewable energy. To this end, it will include general information about thermal efficiency/renewable energy, including but not limited to measure and retrofit options, along with the importance and benefits of thermal efficiency/renewable energy.

On August 21, 2015, the PSB issued an order selecting the contractor recommended by the DPS to create, promote, and maintain the TEPF statewide information clearinghouse, and establishing a $300,000 budget for the clearinghouse project.

7.4.3.2 Building Energy Ratings and Labeling

Energy ratings and labeling can be used to provide information on a building's energy use. This information can vary from very simple data — such as utility/heating fuel consumption covering a certain period of time, the number of people in the household, building square footage, and hours of operation or use — to more complex information that details the building's insulation values and the efficiency levels of its heating systems and other components. A *building rating* takes the building energy usage information and provides a comparison with similar buildings. The energy data and rating can be used to develop a *building energy label*, which can present a simple visual of the information, much like a fuel economy sticker on a new car.

This information can be useful to potential buyers as a means of comparing energy efficiency levels of various buildings and to assess what their future energy costs might be for those buildings. This information may also encourage investment in efficiency on the part of either a prospective buyer or a property seller. For home buyers, this also presents a potential opportunity to include any needed efficiency improvements in an energy-efficient mortgage.

Though they are not mandatory, *seller's property information reports* are commonly provided for homes that are for sale. These reports include recent information on usage of heating fuel and electricity. A limitation of providing energy usage data for the building over only a short period of time is that it is occupant-dependent, and could vary greatly by the number of people occupying a building and how they use it. For example, a four-person household with two adults and two teenagers will likely have energy usage very different from that of a two-person household in the same building. Similarly, a commercial building used for manufacturing or processing will have energy usage very different from one not used for those purposes.

Building energy ratings and labels can also be a tool to provide homeowners with a monetized value of their energy improvements; buildings with a higher rating would likely have a higher value. The inability to monetize energy efficiency improvements is seen by many as a major obstacle to convincing homeowners to go forward with energy efficiency investments.

A number of voluntary building energy-rating systems for new construction are currently available; each certifies that the building has been built to above-energy-code specifications. Examples include the U.S. Green Building Council Leadership in Energy and Environmental Design (LEED) program and the U.S. Environmental Protection Agency (EPA) Energy Star program. One step that has been taken to make energy-rated homes more easily recognized is the addition of the Home Energy Rating System (HERS) score to the Multiple Listing Service (MLS) form, so that home rating scores can be included when available. The DPS sees many benefits in this type of voluntary rating: it can be a positive marketing tool for home sellers, and can enable them to capture the value of their energy efficiency investment when selling their building.

Act 89 of 2013 called for the creation of a "Disclosure Tool Working Group" to "develop a consistent format and presentation for an energy rating that an owner of a building may use to disclose the energy performance of the building or a unit within the building to another person, including a potential purchaser or occupant," and to develop or select "one or more tools that can be used to generate the energy rating." Act 89 also required the DPS to submit a report to the Legislature by December 15, 2013, with regard to the development of a residential building energy disclosure tool; and by December 15, 2014 regarding a commercial building energy disclosure tool. The Act additionally required that the DPS submit a report by December 15, 2016 evaluating the use of the tool, and recommending whether building energy disclosure requirements should be made mandatory.

Residential Building Energy Labeling Working Group

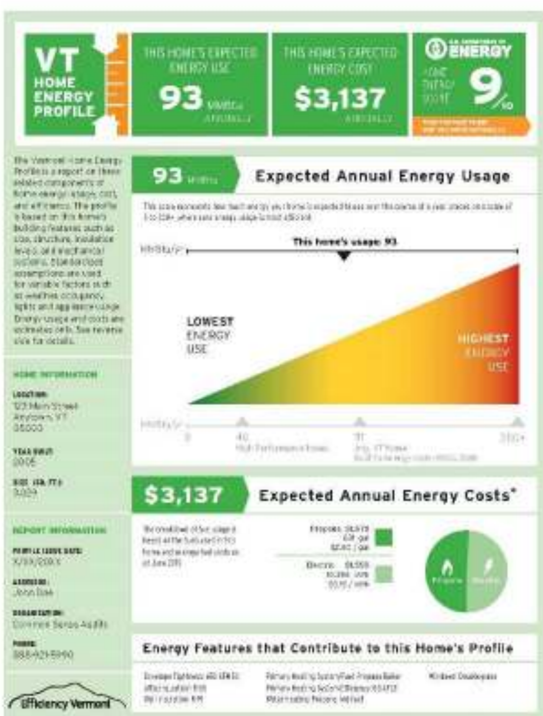
A working group was formed in 2013 that included the DPS, EEUs, Weatherization Assistance Program representatives, and other Vermont organizations with an interest in residential building energy efficiency. The working group met regularly throughout the year, and performed a comprehensive assessment and analysis of relevant issues related to labeling buildings for their energy performance. Multiple stakeholders — including real estate agents, the regional Multiple Listing Service (MLS) organization, home performance contractors, DOE, and others — were also engaged in reviews of proposed scoring metrics and label designs. Draft building energy labels went out for public comment in August 2013, followed by two rounds of Vermont consumer testing.

The working group decided to use DOE's free, nationally recognized energy scoring software to generate the energy ratings that would be incorporated into a Vermont-designed building energy label. The group focused on developing a label that could simply and accurately convey the energy performance of a home, and could be provided as part of a sale or rental transaction. Multiple scoring metrics and different information that should — and should not — be included on a label were discussed and analyzed. In the end, the working group decided that four primary pieces of information should be presented on the Vermont Home Energy Score label:

1. An asset-based, total MMBtu/year projected energy consumption score,
2. Projected energy costs by fuel type,
3. DOE's Home Energy Score, and
4. A general description of the home.

An asset-based score was chosen to allow for consistent comparisons, regardless of who had previously lived in the house and how they had operated it. Projected energy costs were chosen, as that is a measure that homeowners can easily understand. Consumer testing validated that including the DOE logo and score would give credibility to the label, and would allow access to the free scoring software. A draft of the current label is shown in Exhibit 7-3, although it will likely be revised after further piloting.

Exhibit 7-3: Draft Vermont Home Energy Profile



In December 2014, Vermont was awarded a $458,500 grant by the U.S. Department of Energy to advance building energy labeling, benchmarking, and disclosure in Vermont and New Hampshire through policy, implementation, and stakeholder engagement approaches and the creation of a national model for building energy labeling, benchmarking, and disclosure. The grant funds have allowed the efforts to implement a residential building energy rating and label to move forward, with a goal of having ratings and labels issued to EEU and Weatherization Assistance Program participants by the beginning of 2016.

<u>Commercial and Multifamily Building Energy Labeling Working Group</u>

A commercial building energy labeling working group was formed in 2014, made up of the DPS, EEUs, Weatherization Assistance Program representatives, and energy efficiency experts. The group came to consensus on near-term and longer-term approaches for labeling commercial, multifamily, and mixed-use buildings. Near-term recommendations included:

- Use EPA's ENERGY STAR Portfolio Manager (ESPM) as the tool to benchmark buildings and generate an energy rating and label;
- Use actual operational energy consumption data, with energy use intensity (EUI, measured in kBtu/square foot/year) as the primary metric;
- Engage and work with the private sector through EEU programs to deliver and implement benchmarking and labeling services to Vermont building owners and managers.
- The PSB should initiate proceedings to address customer energy data access, and the aggregation, standardized formatting, and storage of data.

For the longer term, the working group identified a number of issues that a subsequent advisory committee would need to address:

- Budgets for supporting these recommendations,
- Schedule that addresses development, label design, and field testing,
- Quality assurance (QA) provider,
- Public access to labeled building results, and
- Tenant lease language.

As a next step, the working group recommended convening an advisory committee to develop and implement an overall benchmarking and labeling plan, to provide coordination between EEUs to develop and test the energy label, to develop and coordinate software to generate the labels, and to design the storage database.

Efforts to promote and support benchmarking and labeling programs will require a concerted and ongoing focus in order to break into the market, gain awareness, earn recognition, and increasingly drive opportunities to save energy.

Recommendations

(1) Continue the steps necessary to implement both residential and commercial building ratings and labeling in Vermont, including convening the Advisory Committees.

(2) *Complete an evaluation of the voluntary building rating and labeling efforts once they've been implemented for at least one year, and submit a report and recommendation to the Legislature on whether building energy ratings and labeling should be made mandatory.*

7.4.4 Existing Thermal Efficiency Programs and Tools

7.4.4.1 Energy Transformation in the Renewable Energy Standard

One of the newest tools for thermal efficiency is the *energy transformation* (Tier 3) requirements of the Renewable Energy Standard (RES), enacted through Act 56 of 2015. These requirements provide an opportunity to bring electric distribution utilities (DUs) as new partners into the building and industrial heat sectors. The DUs have obligations, beginning in 2017, to help their customers reduce fossil fuel use; the likely targets of their actions are fossil fuels burned for building and process heat. DU annual fossil fuel savings obligations begin at a level defined as 2% of their retail electric sales, and rise two-thirds of a percent per year to 12% in 2032 (converted to Btu equivalents as though the fossil Btu were burned in an average power plant).

The PSB has only recently opened a proceeding to establish rules for the program, so DUs have not yet established partnerships and programs to meet this obligation, and measures such as heat pump retrofits are not yet fully characterized. However, initial analysis can shed some light on the program's potential. DPS modeling suggests that the 2% obligation for 2017 could be met through the installation of about 1,100 residential and commercial heat pumps (each displacing the equivalent of about 350-400 gallons of fuel oil); the retrofit of about 500 homes to reduce heat demand by 20%, paired with heat pump installation in those homes; and about 700 electric vehicles sold. Each additional year's obligation rises from this level. By 2032, this path would lead to about 45,000 homes weatherized and more than 90,000 heat pumps installed.

DUs bring new kinds of resources as well. They have ongoing relationships with their customers that can open the door to new ways of marketing energy efficiency and clean fuel options. They can aggregate demand from their customers to buy in bulk. Their monthly bills can be used for on-bill financing or lease programs, potentially including financing that stays with the meter rather than the tenant, thereby helping to address the split incentives inherent in landlord-tenant situations.

Chapter 11 discusses the RES, including energy transformation program design, in more detail.

Recommendations

(1) *Ensure that all ratepayers have an equitable opportunity to participate in, and benefit from, energy transformation projects regardless of rate class, income level, or provider service territory.*

(2) *Ensure the coordinated delivery of energy transformation projects with the delivery of similar services, including low-income weatherization programs.*

7.4.4.2 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 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 DPS updated the residential and commercial energy codes in 2014, starting the public process in February and adopting the new codes in November. Based on IECC 2015, they went into effect March 1, 2015, as Vermont became the first state to adopt the IECC 2015. The DPS also adopted the first Vermont residential stretch code, which goes into effect December 1, 2015. The DPS was given the authority to 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 for the code to achieve a certain percentage of greater efficiency. Act 89 also states that the stretch code shall apply to all Act 250 projects, and that it can also be adopted by municipalities. The DPS has also developed Commercial Stretch Energy Guidelines, which will be used by the Natural Resources Board for commercial Act 250 projects.

One benefit of having these defined stretch codes and standards is that, if a municipality wants to adopt an above-base-code standard, this provides an option that can maintain consistency across the state (versus each municipality choosing different above code standards such as Energy Star or LEED). The same is true for maintaining consistency throughout the state with various Act 250 district commissions.

In addition to more stringent insulation and air leakage requirements, the residential base and stretch energy codes also allow renewable energy to be used for the first time to meet the target Home Energy Rating Scores for compliance. There was also a change for historic buildings, which previously were exempt from the energy codes. In the new energy codes, historic buildings must comply with the standards unless a historic building exemption report has been submitted to SHPO, demonstrating that compliance with a particular provision would threaten, degrade, or destroy the historic form, fabric, or function of the building. The SHPO will then review and validate the exemption request. This change encourages the implementation of efficiency improvements when appropriate, while allowing for exemptions when necessary, with the goal of an overall improvement in the efficiency of older buildings in Vermont.

Additionally, the residential stretch code and commercial stretch energy guidelines have electric vehicle charging requirements.[139] These include having a socket capable of providing either a Level 1 or Level 2 charge for up to 4% of the total parking spaces (the percentage varies in the commercial guidelines based on the type of facility).

Changes were also made to the residential energy code that provide more clarity on the requirements for additions, alterations, and repairs to existing homes. Existing home requirements were condensed into one chapter, with further clarity on what is considered additions, alterations, and repairs; what standards need to be met; and the exceptions for complying with the energy code. Only portions of a building that are being altered must be brought into compliance with the code, not the entire building. The new code also specifies that existing ceiling, wall, or floor cavities exposed during renovations do not need to meet the insulation R-value requirements; they just need to be filled with insulation.

As part of the energy code update process, the DPS facilitated an economic analysis on the proposed new residential energy code, with assistance from EVT and input from some Vermont builders. The analysis compared the minimum base requirements for the 2015 RBES to the 2011 RBES for typical single-family new construction. Estimates were completed for the following benefit-cost perspectives: simple payback, return on investment, savings to investment ratio, and cash flow. Across the four benefit-cost perspectives, incremental costs associated with the base code and stretch code, as compared to 2011 RBES requirements, are offset through the significant energy savings that accrue. The analysis did not take into account escalating fuel costs — so saving projections are likely to be conservative, with the payback being lower than estimated.

Below are the four benefit-cost perspectives with weighted energy savings across all 2015 base and stretch code prescriptive packages, along with high and low energy-cost savings based on various fuel types — heating oil, propane, natural gas, and electricity (assuming that cold-climate heat pumps are used for building heat, rather than electric baseboard heating) — for each prescriptive package.

Simple payback results (incremental cost divided by annual energy savings):

- 5.3 years for base code (individual fuel-specific scenarios range from 4.3 to 12.4 years).
- 7.4 years for stretch code (individual fuel-specific scenarios range from 6.6 to 15.8 years).

Return on investment (annual energy savings divided by incremental cost):

- 19% for base code (individual fuel-specific scenarios range from 8% to 23%).
- 13% for stretch code (individual fuel-specific scenarios range from 6% to 15%).

Savings to investment ratio (annual energy savings divided by incremental cost, times the lifetime of the energy measures):

- 4.7 for base code (individual fuel-specific scenarios range from 2 to 5.8).
- 3.3 for stretch code (individual fuel-specific scenarios range from 1.6 to 3.8).

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[139] The residential stretch code requires the electric vehicle charging for multifamily developments of 10 units or more.

Cash flow (annual energy savings minus incremental mortgage cost of the energy measures):

- $440 annual net positive savings for base code (individual fuel-specific scenarios range from $68 to $590).
- $591 for stretch code (individual fuel-specific scenarios range from $15 to $730).

As shown in the cash flow perspective, when the incremental costs for base or stretch code are included in a mortgage, as would typically be the case for most home purchases, there is net positive savings on an annual basis.

Compliance

The energy codes are verified through a self-certification process, which requires the builder — or, for commercial structures, the builder and architect — to certify that the building was designed and built to code. There is no statewide inspection process to enforce energy codes, but towns that have code officials may conduct inspections for compliance. Building owners also have a right of action to recover damages if the codes are not met.

Municipalities are responsible for receiving and recording the energy code certificates in the town land records; for providing energy code information to applicants seeking a municipal land use permit that will include building a structure (if it will be heated or cooled); and for receiving a copy of the energy code certificate prior to issuing a certificate of occupancy (if they have a COO requirement).

In 2012 the DPS developed an Energy Code Compliance Plan, which outlines an approach for achieving 90% compliance with energy codes by February 1, 2017. The plan recommended a number of priorities to advance the state's energy code compliance efforts, including:

- Focus primarily on commercial and residential new construction at first, followed by renovations and remodeling in subsequent years.
- Require that COMcheck (software) documentation be submitted.
- Coordinate efforts between the DPS and the Division of Public Safety.
- Coordinate and support cities' and towns' code compliance activities.
- Secure funding for up to three full-time positions to support outreach, compliance, and enforcement activities.

Many of the items recommended in the plan have been carried out by the DPS and other partners. Code compliance has also been identified as a priority issue for discussion in the newly formed Energy Code Collaborative (see description below).

The DPS has measured compliance with RBES and CBES in the market assessments that it conducts every three years: these were completed in February 2013 and December 2012 respectively. The technical compliance rate (assessing whether the building met the technical code requirements) for residential was 74%, and for commercial was 88%. The rate for meeting the administrative requirement of completing and posting the energy code certificates in the building was much lower. However, the market assessment was conducted prior to the requirement that municipalities receive an energy code certificate before issuing a certificate of occupancy; it is anticipated that certificate completion rates have likely increased due to that requirement.[140] The DPS has started the process of updating these market assessments, which are expected to be completed in December 2015.

Energy Code Collaborative

The DPS started working with the Northeast Energy Efficiency Partnerships to form an Energy Code Collaborative at the end of 2014, and held the first kickoff meeting in May 2015. The Vermont Energy Code Collaborative is a stakeholder group interested in working toward shared goals that relate to the adoption and compliance of building energy codes. The collaborative will provide a forum to address stakeholder concerns and find appropriate solutions. Part of its mission is "to facilitate compliance with the State's building energy codes statewide and serve as a reliable and unbiased source for information on building energy codes and code compliance in Vermont." The collaborative will meet on a regular basis to take a deeper dive into particular concerns, issues, and the development of solutions.

Training/Outreach

To increase compliance, EVT provides trainings to builders, town officials (including zoning administrators and code officials), architects, design and construction professionals, and market partners (real estate professionals, mortgage lenders, appraisers, attorneys) on the energy code requirements. The outreach to real estate agents has been particularly successful in making sure that energy code compliance certificates are in place, as agents will require this when representing a buyer of a building before a transaction is completed.

EVT, in partnership with DPS, has conducted several trainings on the new energy codes, and it has reached out to towns on the requirement that they provide information on the energy codes when people submit building permit applications, and that they obtain code compliance certificates before issuing certificates of occupancy. EVT also maintains an Energy Code Assistance Center with a toll-free number to provide help on understanding and meeting the codes, including how to fill out the certificates.

Recommendations

(1) DPS should continue to promptly initiate adoption of the International Energy Conservation Code as it is updated, for both commercial and residential buildings.

(2) DPS should map out a path for Vermont energy code progression to achieve the goal of having all new buildings constructed to net-zero design by 2030.

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[140] Although not all municipalities require certificates of occupancy, they are required by most of the larger municipalities, where a majority of the building is taking place.

(3) DPS should continue to measure energy code compliance rates and work with the Energy Code Collaborative on prioritizing and implementing recommendations in the Vermont Code Compliance Plan, to continue to increase statewide compliance.

(4) DPS should work with municipalities considering adopting beyond base code standards and encourage the adoption of the stretch code versus other standards to maintain consistency across the state.

7.4.4.3 Act 250 Energy Efficiency Criteria

Building energy codes in Vermont are supplemented by Act 250, Vermont's land use and development statute that requires review of proposed major development and subdivisions prior to construction. Before a project that falls under Act 250 is permitted, the developer must satisfy a number of environmental, social, and fiscal impact criteria — including criterion 9F, which applies to energy conservation. The statute states that a permit will be granted only if "the planning and design of the subdivision or development reflect the principles of energy conservation and incorporate the best available technology for efficient use or recovery of energy."[141]

As it relates to criterion 9F, *best available technology* has been interpreted to mean the best of proven design techniques and of normally accessible equipment and materials. When evaluating equipment and materials for use, the option that uses the least energy or has the lowest life-cycle costs is selected to comply with this requirement. For commercial buildings, the baseline to satisfy 9F has generally been the Vermont Commercial Building Energy Standards, which replaced the Guidelines for Energy Efficient Commercial Construction in 2012 and were subsequently updated and enacted on March 1, 2015 (this is also the commercial energy code for the state). The DPS is currently working with the Natural Resources Board to develop commercial stretch energy guidelines that can be used by Act 250 district commissions to determine what meets the test of best available technology. For residential buildings, meeting the RBES has been considered compliance with criterion 9F, until December 1, 2015, when buildings will have to meet the residential stretch code.

7.4.4.4 Energy Efficiency Utilities

Beginning in 2010, direct revenues from Vermont's participation in both the Forward Capacity Market and the Regional Greenhouse Gas Initiative have been allocated to EVT and BED for the purpose of developing unregulated-fuel energy efficiency services. Actual funding from 2010 through 2014 totaled approximately $23 million; forecasted funding for 2015 through 2018 is approximately $19.5 million.[142] EVT and BED file annual plans with the PSB every November on what programs and activities will be undertaken with the funds.

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[141] 10 V.S.A. § 6086

[142] Forecasted estimate reflects the proposal filed June 5 2015, which hasn't been approved by the Board to date. The official 2015-2017 TEPF budgets are still the Board-approved budgets issued July 9, 2014 (which are $800,000 less).

At present, thermal efficiency 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.

Recently, the Vermont PSB also appointed Vermont Gas Systems (VGS) to serve as the natural gas energy efficiency utility in its current service territory, although VGS has been offering efficiency services for approximately 20 years.[143] VGS provides natural gas service to more than 40,000 customers in northwestern Vermont and offers both residential and commercial energy efficiency programs for new and existing buildings.

The VGS Residential Retrofit Program focuses on larger users: homes that use at least 0.6 Ccf (hundred cubic feet) of natural gas per square foot per year. The utility provides free energy audits, rebates for approximately 33% of the installed costs of the recommended measures, and a zero-interest or low-interest loan for the remaining costs. VGS also offers an equipment replacement program, with rebates for hot air furnaces, hot water boilers, and water heaters. The VGS residential new construction program provides technical assistance and incentives for building homes to the Energy Star home standard.

For commercial buildings, VGS offers an equipment replacement and retrofit program. VGS conducts free energy audits, offers zero-interest or low-interest loans for energy efficiency improvements, and offers rebates for certain equipment. For new construction, VGS provides technical assistance, including reviews of building plans and energy-efficient equipment information. It also offers financial incentives in certain instances.

Recommendation

Work with participants involved in EEU 2015-02 to complete a transition period plan for 2016 and 2017 for the natural gas energy efficiency utility. DPS will propose to the PSB budgets and targets to acquire all reasonably available efficiency resources that are cost-effective.

7.4.4.5 Vermont's Weatherization Assistance Program

Vermont's Weatherization Assistance Program (WAP) is administered by the Office of Economic Opportunity (OEO). The mission of OEO's WAP is "to help low-income Vermonters save energy, thus money, by improving the energy efficiency and health and safety of their homes." Although the primary

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143 Order in Docket 7676, dated April 20, 2015. In accordance with that Order, the Board commenced a new proceeding EEU 2015-02 to devise a transition period plan to develop short- and long-term efficiency budgets and targets; a process for rigorous, independent verification of savings claims; and mechanisms and a schedule conform the administration of natural gas energy efficiency services to the process currently used by existing EEUs.

focus of the program is energy efficiency, its placement within the Office of Economic Opportunity speaks to its importance with regard to reducing poverty among low-income Vermonters.

The Weatherization Assistance Program was started in 1976 in response to the nation's energy crisis, 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). This is financed by a tax of 0.5% on all non-transportation fuels sold in the state (the gross receipts tax). On average, state resources account for approximately 80% of WAP funding, with DOE providing the other 20%. In 2009, the passing of the American Recovery and Reinvestment Act (ARRA) resulted in a one-time infusion into the program of approximately $21 million ($16 million Weatherization, $5 million SERC funds) of weatherization funding over three years. After the allocation of the large amount of ARRA funding, DOE raised its allowable job cost average to $6,500, which allowed complete weatherization service to clients. Up until that point, DOE funds had been mixed with state funds to allow comprehensive weatherization.[144]

As required under 33 V.S.A. § 2502, the Weatherization Assistance Program is operated consistent with DOE National Weatherization Program rules, with some specific exceptions for go-backs and multifamily eligibility.

Vermont's WAP now serves approximately 750 units per year (see Exhibit 7-4). The OEO works as a partner with EVT to provide efficiency services to these homes. Every dollar spent on efficiency implementation in these homes has returned greater benefits to customers.

Exhibit 7-4. Funding Sources and Number of Housing Units Served by Vermont's Weatherization Assistance Program. Figures are Funds Spent by 5 WAPS and Units/Households Weatherized

YEAR	DOE	WTF / HWAP**	TOTAL	# Units Weatherized
2012-13	$447,003	$10,138,906	$10,585,909	1066
2013-14	$549,443	$11,403,815	$11,953,258	1175
2014-15	$1,015,925	$9,465,957	$10,481,882	1042
2015-16*	$1,000,000	$7,000,000	$8,000,000	751

Source: Geoff Wilcox, Office of Economic Opportunity
* Budget for current year.
** The name Weatherization Trust Fund (WTF) was changed to Home Weatherization Assistance Program (HWAP). Includes GMP funding.

Vermont differs from many other states in that the WAP is administered by the state's anti-poverty agency, OEO. The OEO sub-grants the actual delivery of weatherization services to five community-

[144] Information provided by the Office of Economic Opportunity.

based nonprofit agencies, four of which are community action agencies. This partnering of weatherization with poverty-reduction social services allows for a seamless delivery system with limited redundancies. The nonprofits are able to ensure that clients are aware of their other programs for low-income Vermonters; this often results in clients receiving multiple services. To continue this important leveraging, in 2014 Vermont became the nation's first state weatherization program to refer its clients to the other available health, housing, and social programs. This is done via One Touch Software, to ensure personalized follow-up from each partner program. The Weatherization Assistance Program funded and implemented this Statewide Healthy Homes initiative, to ensure that its clients would benefit the most from their participation in the WAP.

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.

Services provided to clients include:

- An initial visit to the household by an "efficiency coach." This first person in the client's door explains the weatherization process, provides home energy conservation coaching, offers electricity-saving measures and strategies, and performs the ONE TOUCH Referral Survey. The coach also talks with householders how to get the most out of the energy efficiency and health and safety measures installed.
- Comprehensive whole-house assessment of energy-related problems. This done by the energy auditor, who ranks the most important and effective measures to be installed.
- Installation of energy-saving and health and safety measures by each agency's weatherization crew. Heating system tune-ups, repairs, and sometimes replacements are performed by private heating contractors hired by and inspected by the five WAP agencies.
- Testing of every combustion appliance to ensure safe draft and carbon monoxide levels. All issues are identified at the energy audit, then addressed before insulation and air sealing begins.
- Evaluation of the home for moisture problems, and for other health and safety issues.
- Worst-case draft testing, to ensure that the client's home will not encounter back-drafting or combustion issues once the home is tightened.
- Evaluation of the home by the efficiency coach for electricity savings, and installation of cost-effective appliances and lighting. (Funded by EVT.)

Quality control and assurance is an integral part of the Weatherization Assistance Program and a major reason for its success. A quality control inspection is done at the agency level on every job before completion. At the state level, OEO's Energy Services Program Officer completes a rigorous review of

10% of all jobs reported as complete by each agency. All inspections include an infrared scan, blower door test, and interview with the client. All work is evaluated to ensure effectiveness and quality workmanship. If there are quality-related problems on a job, the agency is directed to remediate the problem.

In the last year, the WAP has implemented a statewide, web-based data management system. All five weatherization agencies and OEO use this for the program's daily operation. The agencies use the system for all weatherization activity, from eligibility to final reporting to OEO, and OEO has live access to this information. This has improved the efficiency of administering the state and local programs, and allows OEO to use the data and information to better monitor, manage, and improve the program.

The DOE average budget is now $7,100 per unit, or household, for energy efficiency measures, and $1,000 per unit for health and safety measures. State weatherization funds allow a budget of $8,500 per unit, as a total of energy efficiency and health and safety costs. This allows for the installation of virtually all cost-effective energy-saving measures at a home, plus the ability to address and correct related health and safety issues.

Vermont has some of the oldest housing stock in the country, and the low-income families that apply for weatherization tend to live in the poorest housing stock in the state. Major structural issues preclude weatherization at many homes until outside funds or other forms of help can alleviate the situation. Vermiculite insulation is found in 10% of the clients' homes each year. Before July 2014, this meant deferral of services to anyone with vermiculite, due to the high probability of the presence of asbestos in the vermiculite.

The Weatherization Assistance Program has worked with the Department of Health and VHCB's Healthy Homes Program to develop strategies for dealing with vermiculite. These have been implemented at a handful of clients' homes, and paid for with some recent funding from the Vermont Low Income Trust for Electricity (VLITE). This has given hope to many with vermiculite — yet the number of weatherization clients waiting for help far outstrips the available funding. Over 400 families are on the vermiculite list, and VLITE funding is only enough to treat 60-80 of those homes in the next year. The development of the "hybrid" approach to treatment has created an alternative option to abatement, at a significantly lower cost, but it is still expensive and cannot be funded by normal weatherization funds. More rehab/vermiculite funding is drastically needed, or many families in need will not be able to receive weatherization.

The Weatherization Assistance Program has been providing thorough and cost-effective weatherization services to low-income Vermonters for many years — but thousands of qualifying homes continue to wait for services. Increased funding would also help Fuel Assistance funds go farther for clients who are prioritized weatherization service.

Recommendations

(1) Provide housing rehab funds for low-income clients who live in and own their homes. These funds are needed to address the many structural issues at low-income clients' homes, such as leaky roofs, excessive moisture in basements, etc. These conditions and others prohibit many struggling Vermonters from receiving weatherization service.

(2) Provide dedicated funding to help clients who have vermiculite insulation in their homes treat this material, to then allow weatherization to occur at their homes.

(3) Any additional thermal efficiency funding should ensure an adequate balance of funding between low-income and non-low-income households, and should consider how to best provide services to lower-income households that do not meet eligibility requirements for Weatherization Assistance Program services. Investigate potential opportunities, such as "do-it-yourself" programs, no-interest loans, and needs-based tiered incentives for those who do not meet the eligibility requirements but are unable to afford efficiency measures.

7.4.4.6 Assistance for Energy Improvements in Older Existing Buildings

The long-term goals of historic preservation, energy conservation, and sustainability are not mutually exclusive, and the continued use of existing buildings is an important component of any effort to promote sustainable development. In fact, increasing investment in historic and older buildings, greening the existing building stock, and revitalizing historic downtowns and village centers underpin state efforts to grow the economy, promote investment in location-efficient places, and combat climate change.

Downtown & Village Tax Credit

The Vermont Department of Housing and Community Development administers both state and federal rehabilitation tax credits to stimulate private investment, create jobs, restore historic buildings, and jumpstart revitalization across the state. Projects range from small bed and breakfasts and rental apartment dwellings to multimillion-dollar downtown redevelopments.

The credits support general rehabilitation, including weatherization and efficiency improvements, code compliance, and façade improvements of qualified buildings, and may be combined with the federal program. Both programs use the Secretary of the Interior's Standards for Rehabilitation to ensure that changes are sensitive and appropriate. Vermont ACCD staff can provide specific advice on projects, and are available to meet on site, and to discuss individual projects and how efficiency retrofits can meet both energy goals and preservation standards.

The amount of the credit is based on total rehabilitation costs. The federal credit is 20% of eligible rehabilitation expenses, and the state credit ranges from 10% and 50% of eligible rehabilitation expenses. At the state level, there is an annual cap in credits available, and selection criteria are applied to ensure that credits are allocated to projects that provide the most public benefit. When taxpayers receive allocations under both programs, the return can be as high as 70% of eligible rehabilitation expenses.

While the tax incentives do not specifically target weatherization activities, a new partnership with Efficiency Vermont is working to fill that gap. This includes increased outreach and marketing efforts to raise awareness about the tax credit programs and how they may be combined with efficiency incentives. It makes sense to consider and make energy upgrades while other code-related or general work is ongoing. Working together, ACCD and EVT can provide property owners a more complete set of tools and incentives to improve the safety, accessibility and efficiency of existing commercial buildings, while strengthening our downtowns and village centers by attracting new businesses and creating jobs.

8 Transportation

8.1 Introduction

Transportation is vital to Vermont's economic well-being. It provides for the movement of people and goods, and is a requirement of modern living. The choices we make when taking the numerous trips in our daily lives — whether we walk, bike, ride share, take a bus, or drive alone in a truck or a hybrid car — affect demand on the transportation system.

This in turn dictates the public and private costs of the system; the nature and extent of roads, parking lots, rail lines, and other physical infrastructure; the quality of life and economic opportunity in our communities; and the energy use and costs to individual households, businesses, and the state as a whole.

Transportation fuels account for the largest portion of Vermont's total energy consumption, and they include more fossil fuels than any other energy source. Gasoline and diesel account for more than 35% of all energy consumed, across all sectors. Petroleum combustion in the transportation sector is also the state's largest contributor — at 47% — to GHG emissions.[145]

Shifting to renewable and less carbon-intensive fuels such as electricity, biofuels, and compressed natural gas (CNG) to power cars and trucks will have a significant effect on transportation greenhouse gas emissions (GHG), and on reaching the state's renewable energy goals. Where Vermonters choose to live, work, and recreate, and the location of commercial services, schools, and health care and the associated land use patterns affect the transportation system and traffic levels. Due to the state's rural settlement pattern, Vermonters tend to travel farther from their homes to employment, services, and shops than do many other Americans. More compact settlement patterns have been shown to reduce transportation system demand overall by facilitating transit use, biking, walking, and other options that have the potential to reduce traffic congestion, emissions, and energy use.

In 2013, Vermonters spent almost $1.5 billion to purchase gasoline and diesel fuel — and almost 70%[146] of these expenditures left the state for the purchase of these products from the global petroleum market. Reductions in the use of gasoline and diesel purchases reduce the outflow of dollars.

For example, increased ridesharing and use of transit services reduce the overall use of energy associated with transportation, and those dollar savings are available to be spent within the local economy. When Vermonters switch from gas-powered to electric vehicles, their source of energy changes; and locally

[145] Vermont Agency of Natural Resources

[146] This statistic is developed in Chapter 4.

generated electricity keeps economic activity in Vermont, compared to a large proportion of petroleum profits going out of state.

Vermonters' transportation choices are often market-based, and made according to what makes economic sense for the consumer. State programs and policies should not interfere with those decisions. When the market is slow to transition to more efficient and renewable transportation options, additional calculations of public economic and environmental benefits should help policy makers determine the best use of public resources.

Moving to a new transportation energy future, one that will reduce the transportation sector's contribution of GHGs in Vermont, will require three types of actions — and it is these under which the CEP's recommendations and strategies are considered:

1. Increasing the energy efficiency of the transportation system through:
    a. Land use and development patterns that reduce commute and other trip distances;
    b. Transit, passenger rail, ridesharing, vanpooling, car sharing, biking, walking, and other transportation options that are less energy-intensive then single-occupancy automobiles, as well as shifting from truck to rail freight; and
    c. Home-based work and telecommuting.
2. Increasing energy efficiency through improved vehicle technology.
3. Increasing the use of renewable and less carbon-intensive fuels, such as electricity, biofuels, and compressed natural gas.

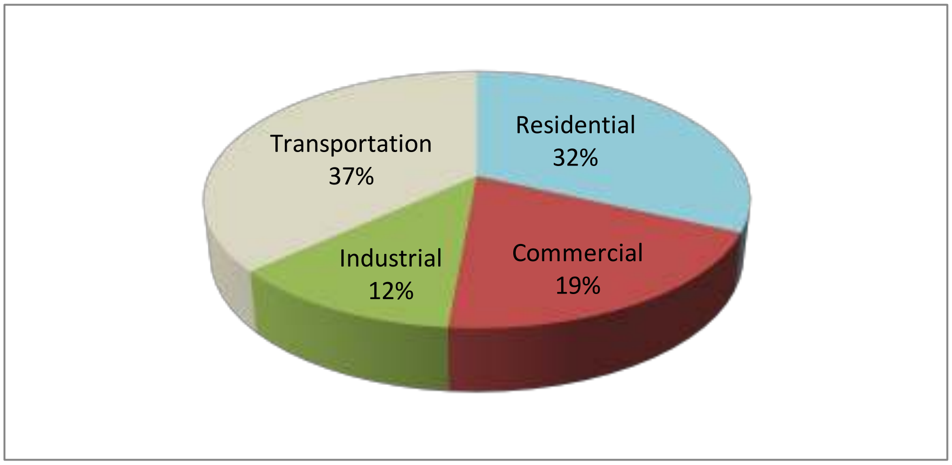
The following pages provide background information on Vermont's transportation energy use, goals, opportunities, challenges, and recommendations to advance these actions.

8.2 Transportation and Vermont's Energy Use

Petroleum Consumption

Exhibit 8-1 shows transportation petroleum consumption in Vermont compared to other uses.

Exhibit 8-1. Use of Petroleum in Vermont, By Sector, 2013



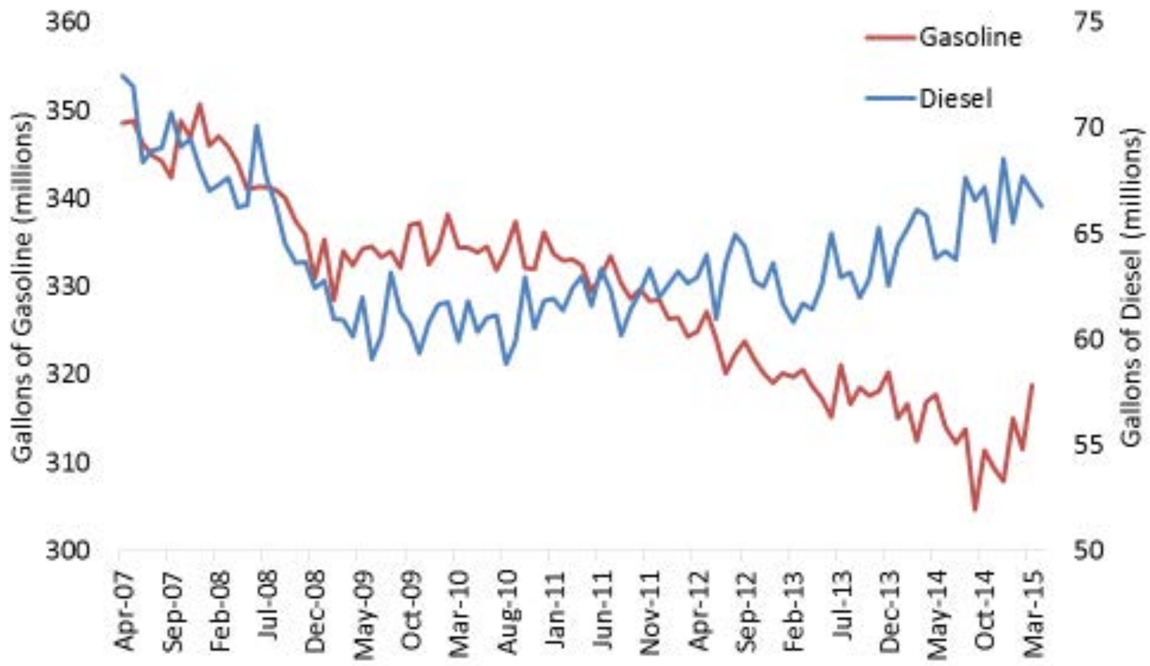
Gasoline sales have fallen steadily since 2007 in Vermont while diesel has risen, as the next chart illustrates. The gasoline sales trend is related to improvements in the overall fuel efficiency of the Vermont light-duty vehicle fleet, as well as a decline in vehicle miles travelled (VMT) during this period.

Exhibit 8-2. Liquid Fuel Sales in Vermont, 2005-2014

	2005	2008	2010	2011	2012	2013	2014
Gasoline	360	336	332	328	320	318	309
Diesel	67	62	62	62	63.6	62.6	68.6
Biodiesel	0.054	0.392	--	--	--	--	--
CNG	--	0.015	0.025	0.054	0.104	0.143	0.146

Notes: Gasoline, diesel and biodiesel sales are reported in millions of gallons. CNG sales are reported in millions of gallons of gasoline equivalent.
Sources: VLJFO, 2015; White, 2009; Vermont Gas, 2015

Exhibit 8-3. Gasoline and Diesel Sales in Vermont, Rolling 12-Month Total, 2007-2015

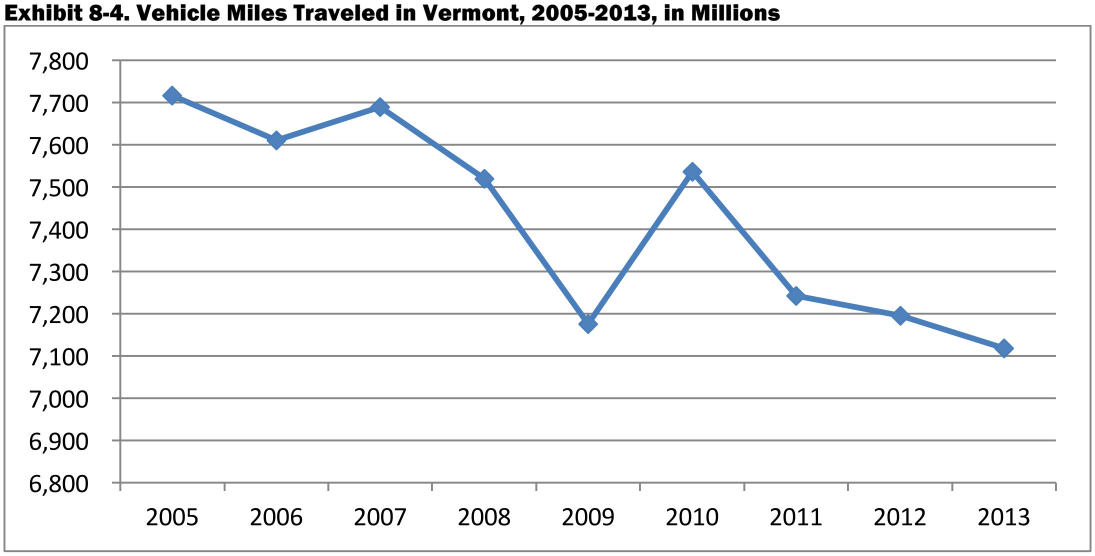


Source: Joint Fiscal Office, 2015

Vehicle Miles Traveled — the Number of Cars and Trucks on Vermont Roadways

VMT (vehicle miles traveled) is the number of miles traveled within Vermont, and is a common measure of all the usage of cars and trucks on the state's transportation system. VTrans estimates VMT annually.

Exhibit 8-4. Vehicle Miles Traveled in Vermont, 2005-2013, in Millions



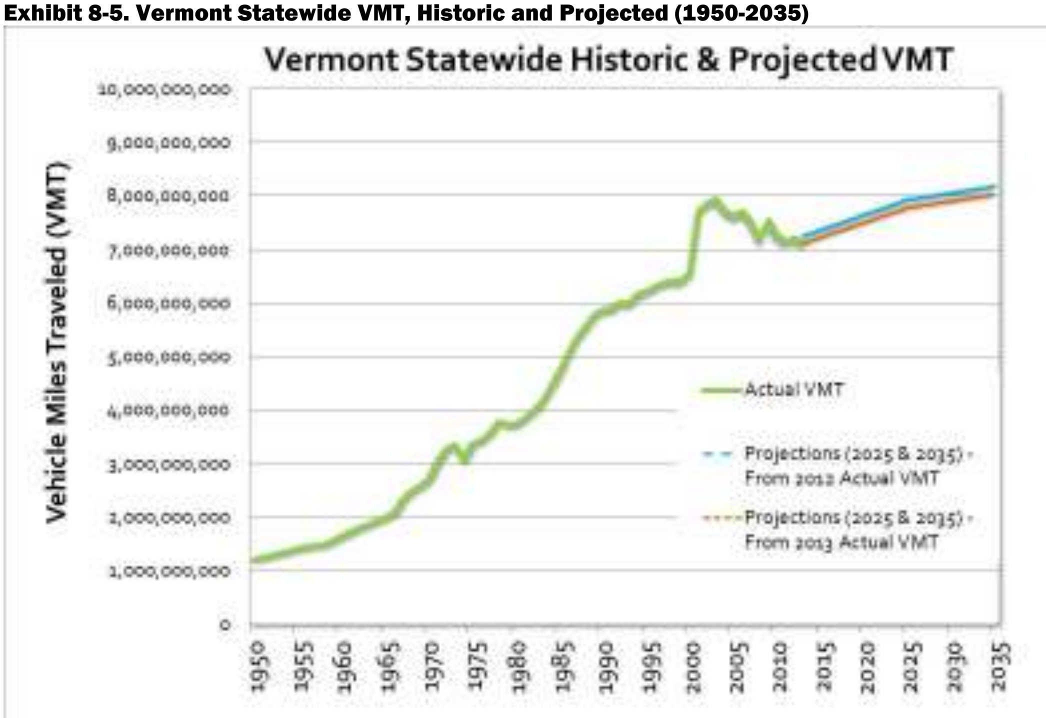
Source: VTrans Highway Research

After decades of growth and a doubling of the number of cars and trucks on Vermont roadways between 1975 and 2009 (3.3 billion VMT in 1975 to 7.1 billion VMT in 2009), VMT has declined almost 10% between 2003 and today.

This decrease is believed to have been caused by a variety of factors. These include the economic recession that started in 2008; sustained high gas prices that also started in 2008, and resulted in behavioral changes — people adapted their commute/utilitarian trips (carpooling, use of public transit, etc.); and changing travel preferences, particularly among teens, young adults, and the aging population in Vermont. Recent declines in gas price may reverse this trend.

A future VMT trend that is flat or decreasing will help indicate this plan's success. A slower but steady rise is more likely if current policies and low fuel prices continue. The next graph shows projections of statewide VMT, based on assumptions and growth rates from the Vermont Travel Model.

Exhibit 8-5. Vermont Statewide VMT, Historic and Projected (1950-2035)



Source: ANR Air Quality Division

8.3 Goals for Transportation Energy Use Reduction and Increase in Renewable Energy

Reduce total transportation energy use by 20% from 2015 levels by 2025. This can be accomplished through transportation-system energy efficiency; land use and development that reduces daily trips; home-based work and telecommuting; shifting to transit, passenger rail, ridesharing, vanpooling, car sharing, biking, walking, and other transportation options that are less energy-intensive then single occupancy automobiles; and increased energy efficiency through improved vehicle technology.

Objectives for 2030, based on a 2011 baseline, to assess progress in reducing transportation energy use, include:

- Hold VMT per capita to 2011 levels.
- Reduce the share of single-occupancy vehicle (SOV) commute trips by 20%.
- Double the share of bicycle and pedestrian commute trips to 15.6%.
- Triple the number of state park-and-rides spaces to 3,426.
- Increase public transit ridership by 110% to 8.7 million trips annually.
- Quadruple Vermont-based passenger rail trips to 400,000 trips annually.
- Double the rail freight tonnage in the state.

Increase the share of renewable energy in all transportation to 10% by 2025 and 80% by 2050, by promoting the adoption of electric vehicles and by increasing the use of other renewable and less carbon-intensive fuels, such as biofuels, and CNG, especially in segments of the transportation sector where electrification is a less feasible or affordable alternative.

Objectives to help assess progress in increasing the share of renewable energy in transportation include:

- 10% of the fleet are EVs by 2025.
- 10% renewably powered heavy-duty vehicles by 2025.

Reduce transportation-emitted GHGs by 30% by 2025, through reduced consumption and increased renewables, by undertaking the strategies above and by keeping biofuels carbon-neutral.

8.4 Transportation Efficiency through Land Use Strategies

Where Vermonters choose to live, work, go to school, shop, and recreate affects the amount of energy and money spent in moving across the landscape, and contributes to the state's total VMT. To achieve greater transportation system efficiency, land use and transportation planning must be successfully integrated.

Compact development patterns have the potential to reduce the number of miles between daily travel destinations, and also make alternative travel options (walking, biking, car pooling, and transit services) more viable. Vermont's longstanding land use goal is to plan development in ways that maintain the historic settlement pattern of compact village and urban centers separated by rural countryside (24 V.S.A. Chapter 117).

Beyond the energy savings realized by reducing VMTs in compact centers, studies also show that as housing is located farther from town centers, homes become larger and housing types are more likely to be single-family homes[147]. According to a study undertaken by Reid Ewing and Fang Rong[148], similar households are likely to choose homes 23% larger in less compact areas, and seven times less likely to live in multi-family housing. Compared to households living in multifamily units, otherwise comparable households in single-family detached units consume 54% more energy for space heating. Using a county sprawl index[149], the authors estimate that energy use associated with housing for similar households in compact counties will be 20% less than in sprawling counties, due to size and type differences. These studies also do not take into account the reduction in electric transmission and distribution losses that compact development makes possible.

Planning the state's energy future thus depends on local and regional planning entities planning for development within a land use pattern that is compact, mixed-use, and thus sustainable. While today's greater focus on downtowns, villages, and neighborhoods in Vermont has the potential to contribute to the recent decrease in VMT, an estimated 78% of residential structures built between 2005 and 2014 of were built outside of areas identified by Regional Planning Commissions as "community centers."[150]

Higher density alone is not the answer. Studies have revealed that the biggest determinants in whether people decide to walk or bike instead of using an automobile are design, density, destination accessibility, diversity of uses, access to transit, and availability of free parking[151]. Lowering vehicle miles traveled by getting people out of their automobiles requires investment in careful planning and design that accounts for all these factors.

A Federal Highway Administration report reflecting 2009 travel patterns shows that at the national level, almost 30% of household vehicle miles traveled were linked to commuting, and more than 30% were associated with shopping and other personal errands. About 25% of household vehicle miles traveled were for social and recreational trips[152].

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147 Edward L. Glaeser and Matthew E. Kahn, *Sprawl and Urban Growth. Discussion Paper No. 2004* (Harvard Institute of Economic Research, 2004)

148 Reed Ewing and Fang Rong, *The Impact of Urban Form on U.S. Residential Energy Use* (Housing Policy Debate, 2008) www.arch.utah.edu/cgi-bin/wordpress-metroresearch/wp-content/uploads/2013/09/Most Cited Articles/ewing_rong_article.pdf

149 Reid Ewing, Richard Schieber and Charles Zegeer, "Urban Sprawl as a Risk Factor in Motor Vehicle Occupant and Pedestrian Fatalities," *American Journal of Public Health* (September 2003), citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.232.7778&rep=rep1&type=pdf

150 Enhanced 911 building locations, 2005 & 2014

151 Julie Campoli, *Made for Walking: Density and Urban Form* (Lincoln Institute of Land Policy, Cambridge, Mass., 2012), www.lincolninst.edu/pubs/2150_Made-for-Walking

152 National Household Travel Survey, 2009

8.4.1 Commute Trips

Commuting to work by car accounts for a large portion of the state's transportation energy demand — and it involves repeated, predictable trips with consistent origin and destination points. Commuting trends are also more easily measured, thanks to U.S. Census and other data. For those of us who do travel to our workplace, shifting our mode of commuting from single-occupancy vehicles (SOV) to ridesharing and other alternatives tends to pose fewer challenges than shifting our trips that involve activities such as shopping or recreation.

Despite Vermont's rural character, a significant number of work trips are short enough to allow for walking, bicycling, and local transit. This is good news, and it presents an opportunity to shift these short work commute trips away from SOVs.

The U.S. Census Bureau performs annual surveys since 2005 that track changes in commuting behaviors. Exhibit 8-6 shows commuting data for all of Vermont and just for Chittenden County.

Exhibit 8-6. Commute Trip Data for Vermont and Chittenden County (Presented as State/County)

	Avg. commute time (min.)	Percent responses >30 min. commute	Percent using public transit	Percent walking	Percent biking	Percent working at home	Percent driving alone
2005	21.2/*19.3*	26.7/*19.7*	0.9/*1.6*	5.2/*6.8*	0.5/*1.3*	5.5/*4.7*	75.8/*74.6*
2006	21.2/*20.2*	27.6/*22.9*	0.8/*1.8*	6.1/*8.8*	0.5/*1.0*	5.4/*3.7*	75.1/*73.8*
2007	21.2/*19.9*	27.6/*22.1*	0.9/*2.1*	6.2/*7.1*	0.5/*1.5*	6.4/*4.9*	74.6/*72.8*
2008	21.9/*19.9*	28.4/*23.8*	0.9/*2.6*	6.3/*8.9*	0.6/*1.7*	6.7/*5.2*	73.3/*71.0*
2009	21.9/*20.4*	28.7/*22.7*	0.9/*2.1*	5.4/*6.7*	0.8/*1.7*	7.2/*5.8*	74.8/*73.7*
2010	21.7/*19.1*	28.0/*20.9*	1.3/*3.1*	5.5/*7.5*	0.6/*1.4*	7.4/*7.4*	74.9/*70.8*
2011	21.9/*20.3*	27.9/*20.1*	1.4/*3.1*	6.3/*7.2*	0.8/*2.0*	6.2/*5.5*	74.3/*72.7*
2012	23.1/*20.4*	30.6/*21.7*	1.2/*2.1*	6.1/*7.6*	1.0/*2.5*	7.3/*7.5*	73.5/*70.6*
2013	22.5/*20.6*	29.7/*24.6*	1.2/*2.5*	5.3/*6.9*	0.9/*2.5*	6.8/*6.9*	75.4/*71.5*

Source: American Community Survey

While many of the trends during this time period are not significant, it is worth noting that driving alone is the predominant mode of travel throughout the state — and only bike riding and transit are showing any significant increases. It's also notable that biking, walking, and transit commuting are more common in the more densely populated Chittenden County region.

Also during this time, overall population growth rates were higher in Chittenden County than in other parts of the state. A greater diversity of available transportation options, along with the attractiveness of more densely populated areas, may have contributed to that growth.

Other than commuting, there is no easily captured statistic to gauge the trends in vehicle use. However, the overall relationship between the rural nature of a state and the increased use of vehicles cannot be explained by commuting alone; more rural areas also have greater distances to travel for shopping, schools, and appointments. The data showing per-capita VMT in different Vermont counties bears this out. Data reported by the Governor's Highway Safety Program[153] shows that road travel in Chittenden County involves 10% and 50% fewer miles per capita than in other counties. The data on commuting, such as average commute time, suggests that only a small part of that can be attributed to home-to-work travel.

Many Vermonters travel as a part of their job, not just between home and work but also between businesses for sales and service, and to provide delivery services. In addition, the bulk transportation of goods, largely via truck but also by train, adds a significant factor to the transportation demand in Vermont.

Just as with commuting and daily activity travel, the distance between destinations for commercial transportation is dependent on the density of the businesses and services. While much of the transportation may be between cities and towns, at least a portion of the travel demand has the potential to decrease with greater settlement density.

8.4.2 Strategies

As Vermont looks to reduce growth in VMT, smart-growth land use planning is an obvious and valuable tool for getting us there.

The state has a longstanding goal of encouraging concentrated mixed-use development in and around community cores, while protecting natural resources and working landscapes outside those areas. This traditional land use pattern supports a variety of public interests, including reduced development pressures on agricultural, productive forest, and natural resource lands; increased housing options; continued use of our historic resources; a strong Vermont brand; economic efficiency; and active community centers.

This land use pattern also reduces the demand for energy to move people from their homes to work, shopping, school, or social gatherings. Within an area of compact development:

- More people can walk to their destination.
- There are opportunities for biking and other alternate modes of transportation.
- More effective transit systems are possible, both within communities and between communities, because successful transit systems depend on having a large and concentrated ridership base in core community areas.
- Commuters have a relatively common origin and common destinations, increasing carpooling opportunities.

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153 ghsp.vermont.gov/sites/ghsp/files/Reports_and_Data/County%20Breakdown%20Annual%20VMT%202011.pdf

Although the state has been subject to significant development pressures over the past decades, it has not experienced the same degree of sprawl and disconnected rural development as have other states around the country. Vermont's downtowns and villages remain largely intact, and public interest in and support for smart growth has been increasing. In fact, although it is widely seen as a rural state, much of Vermont's population lives or works in its core communities: the 24 municipalities that each host one of Vermont's designated downtowns account for more than 30% of the state's population.

While changing land use through the planned location of new development is a slow process, the results will last for decades.

Future development that is focused in designated downtowns, villages, and growth areas will reduce the demand for travel miles in the future, and will accomplish the many other goals supported by smart growth, including job growth and healthy lifestyles.

The strategies for reducing transportation-related energy are the same as the state's existing set of policies for compact land use. Supporting policies presented in the 2011 Comprehensive Energy Plan include these:

- Vermont's Municipal and Regional Planning and Development Act (24 V.S.A. Chapter 117) includes specific land use goals and required plan elements. Most relevant is the goal to "plan development so as to maintain the historic settlement pattern of compact village and urban centers separated by rural countryside." The Act enables municipalities to adopt zoning, subdivision, and other tools to regulate development. The Act also created the Municipal Planning Grant (MPG) program, which currently grants $400,000 to support municipal plans, bylaws, infrastructure planning, and related activities. Municipalities must continue to focus on meeting this goal, and MPG funding must be used to support a more compact development pattern, supporting our community centers.

- The Municipal and Regional Planning and Development Act provides for the creation of regional planning commissions, and requires the development of regional plans, including a land use element and an energy element. It also enables these commissions to undertake a wide variety of other activities — including participation in Act 250, transportation planning, support of municipal land use planning and regulations, and a wide variety of other planning activities. These regional commissions currently receive substantial state funding — and it is important for those funded activities, including training of municipal officials, to continue to support a compact development pattern.

- Municipal capital budgets (24 V.S.A. § 4430) provide for sewer, water, road, parking, pedestrian/bike facilities, and other municipal improvements. The kind of compact development pattern anticipated in statute is not possible without investments in such improvements. These improvements can also be used to promote sprawl and strip development — so it is vital to maintain investment focus on supporting well-planned, dense-growth areas located close to the community core.

- Act 250 (10 V.S.A. Chapter 151) is a statewide permitting process that protects a wide variety of natural resources — water, soils, habitat, aesthetics — and ensures that public infrastructure, such as transportation, water, and wastewater systems, is adequate to serve proposed development. Development proposals must demonstrate that energy will be used efficiently, and that the development will not place an unreasonable burden on utilities. Applications must also comply with municipal and regional plans, including provisions in those plans that relate to energy.

- The Downtown Development Act (24 V.S.A. Chapter 76A) was created to revitalize the state's downtowns and village centers. Subsequent changes to the Act created programs to support new development in growth centers and neighborhoods. The designation processes for all these programs ensures that the designated areas provide for compact, mixed-use development. The Act provides dedicated support of these areas — including transportation grants, rehabilitation tax credits, tax increment financing districts, and modified Act 250 thresholds — and directs a number of state funding programs to give priority to these areas. These programs could be strengthened and better integrated, providing a more comprehensive foundation for the state's smart growth strategies.

- State infrastructure expenditures are enormously influential in supporting growth. Other states are increasingly focusing state investments to support compact, smart-growth areas, and it is critical for Vermont investment policy to do a better job of directing such funding to community centers. These investments also make financial sense, serving more users in a smaller area while supporting a development pattern that minimizes dependence on single-occupancy vehicles.

These supporting policies remain in effect. Lessons learned and successful programs implemented since the 2011 CEP have highlighted other policy and program recommendations:

- Direct additional public sector funds, if and when available, to downtown redevelopment, in order to control the long-term costs for supporting energy services and infrastructure related to sprawl development.

- Increase funding for municipal planning grants, to help municipalities develop integrated plans and policies, and restore municipal education grants. Because all residential development in Vermont is subject to local regulations, helping to improve municipal bylaws will allow for greater densities, better design, diversity of uses, and lower parking requirements — all proven to be effective in lowering vehicle miles traveled. ACCD's forthcoming *Planning Manual* update will help municipalities work towards such improvements, and municipal planning grants have continued to prioritize projects that work on the creation of walkable centers.

- The state currently invests in several programs that coordinate transportation and land use investments in ways that promote walkable, bikeable environments, including Strong Communities, Better Connections and the Neighborhood Development Area (NDA) Designation

Program. Working together, the Agency of Transportation (VTrans) and ACCD developed Stronger Communities, Better Connections, a new initiative that uses existing funding to create a joint grant program to help communities coordinate transportation and land use planning and prioritize investments that meet multiple goals. The NDA program has been updated in recent years to focus on increasing housing in walkable neighborhoods, and to respond to improvements suggested by local municipalities and developers. Continuing the Stronger Communities, Better Connections, expanding to include ANR in natural resource planning, and continued investment in benefits for NDAs will provide support for local communities in helping create an environment where alternatives to single-occupancy vehicles are safe and available.

- One of the biggest incentives for driving to work alone in the United States and in Vermont is free parking — an enormous untaxed benefit that most employers offer their employees. But whether employers or taxpayers are paying for it, parking is of course never free. Studies show that, on average, shifting parking costs from employers to employees reduces single-occupancy vehicle use by 25%. But given that most commuters consider free parking a basic right, charging for parking when employees currently pay nothing could be challenging. One successful alternative is to have employees choose cash instead of a free parking space, a practice known as *cash-out*. The State of California has made parking cash-out required for employers with greater than 50 employees. Studies of employers who have switched to a cash-out system have experienced an average VMT reduction of 12%. As the biggest employer in the Vermont, the state has an opportunity to employ this strategy to help reduce VMTs, and should consider a pilot a parking subsidy cash-out program in high demand locations.

8.5 Reduce VMT through Increasing Transportation Choices and Increasing Transportation Efficiency

Moving into a new transportation energy future will require the Agency of Transportation, the Vermont Legislature, the private sector, and individual Vermonters to shift the way transportation is planned, funded, and used — from being a physical infrastructure issue, dominated by accommodating automobiles and freight on roads and bridges, to an energy-efficient and sustainable system that provides mobility options for all and serves drivers as well as passengers, pedestrians, and cyclists.

Today, transportation priorities at the state and municipal levels are focused primarily on maintaining roads and bridge infrastructure so that cars and trucks can travel safely throughout the state. This function must continue if the state is to thrive, but other mobility options will be needed in the future as traditional energy sources become scarcer and costlier.

Transportation funding sources are insufficient to meet current and future roadway infrastructure preservation and maintenance needs. Funding demands related to options such as increased rail and transit services should not compromise addressing the need to preserve and maintain basic infrastructure. Building a new mobility system calls for creative use of both existing and new sources of revenue.

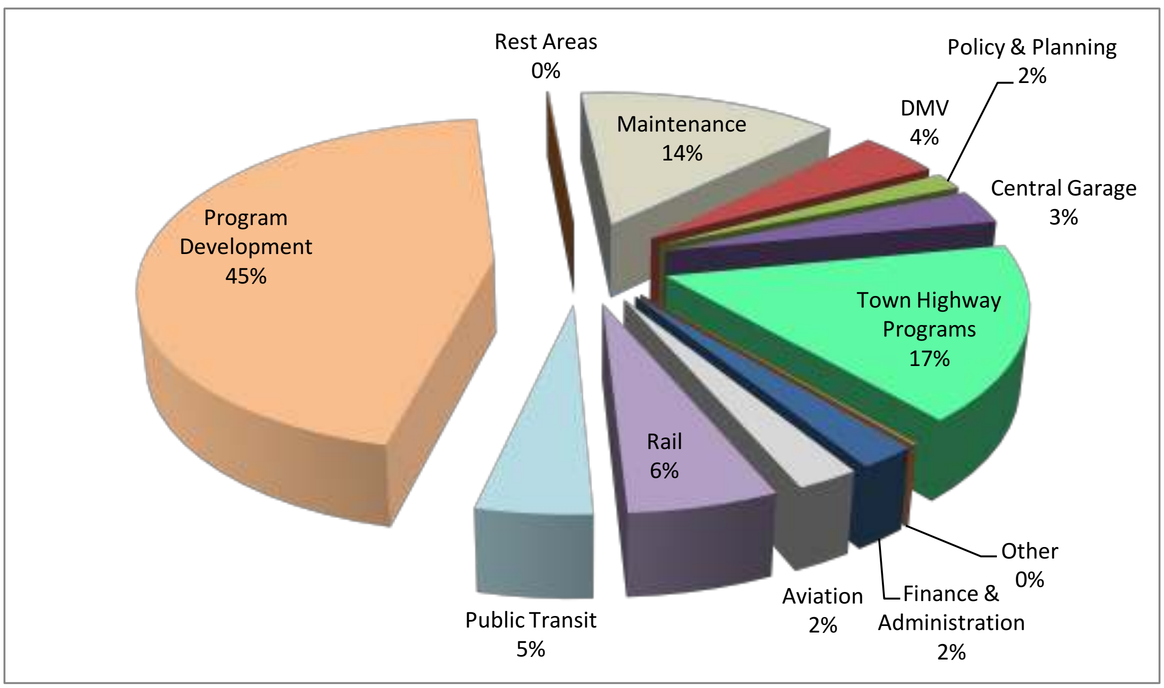
Vermont's transportation system includes:

- 14,266 miles of roadways maintained by VTrans and municipal governments, including 320 miles of interstate highways and 765 miles on the National Highway System;
- 601 miles of rail serving both freight and passenger needs;
- 16 public-use airports; and
- 10 regional transit providers that provide more than 100 transit routes throughout the state.

There are also services and infrastructure to support biking, walking, and ridesharing, along with private-sector partners including intercity bus services, Amtrak, taxis, Uber, and other services.

The state investment in transportation is reflected in the VTrans 2016 budget shown in Exhibit 8-7. This does not include the significant municipal contribution to transportation, primarily for road and bridge upkeep and maintenance.

Exhibit 8-7. VTrans Budget by Program Area, Fiscal Year 2016



Source: VTrans

"Program Development" is primarily state roadway and bridge design and construction, although a small portion, 2%, is for bicycle and pedestrian facilities.

Transit, passenger rail, walking, biking, car sharing, and ridesharing — all less energy-intensive than single occupancy vehicles — are a state priority. This is reflected in VTrans's strategic vision: *A safe and efficient multi-modal transportation system that promotes Vermont quality of life and economic well-being*. The support has shown results by increasing transit and passenger rail ridership and use of Go Vermont's rideshare services.

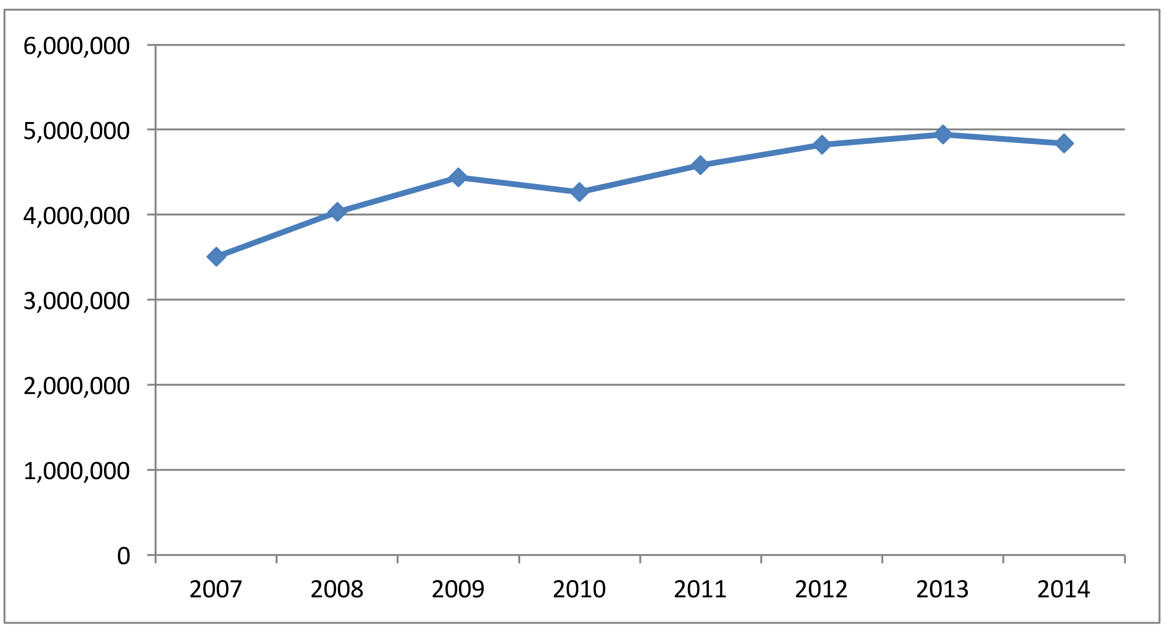
Transit options and increased walking and biking, paired with smart growth, have been shown to have economic and other benefits, including healthier communities. There are indications nationally that robust passenger services and walkable/bikeable communities are what young people desire, and also have benefits for an aging population.

8.5.1 Public Transit

The state spends a generous portion of its transportation budget on the capital and operating needs of the state's nine public transit providers. Local transit providers offer a range of services, including fixed and deviating routes, commuter transport, and demand response.

Vermont is recognized as a national leader in the provision of rural public transit — not only devoting substantial levels of state funding, but also "flexing" highway funds into public transit.

Exhibit 8-8. Public Transit Ridership in Vermont, 2007-2014



Source: VTrans

The state will continue its commitment to transit by flexing federal funds, partnerships, and innovation, and increasing transit investment in areas that have the land use density necessary to support it, and in key corridors that link commuters to their jobs.

VTrans is entering into partnerships with national companies and groups to move into web-based ridership availability platforms, both to improve information about available services and to increase the use of available seats in all types of transit. This includes demand response and carpool and vanpool trips, along with possible feeder services to fixed route systems in a micro-transit atmosphere.

VTrans has also made significant investments in upgrading its public transit infrastructure, with new maintenance facilities, new dispatch and billing software that will allow the use of AVL (automatic vehicle locators), modern fare collection technology, cross regional ridesharing and stronger coordination, and GTFS mapping of all fixed routes in the state so that commercial trip planners can provide information on available trips in Vermont.

8.5.2 Intercity Bus

Vermont leadership, businesses, and residents have recognized that with the reduction in Greyhound services connecting Vermont to the rest of the bus-riding world, more connections need to be forged. A 2012 planning study of the need for intercity bus service identified a number of potential intercity routes that might meet the need of the traveling public. Two of these routes were designed and put out to bid, resulting in connectivity to Albany, New York from Colchester along the old Greyhound run on Vermont Rte. 7. Connectivity across the state was achieved with a connection along Rte. 4 from Rutland to White River Junction.

With one year of service completed, ridership on Rte. 7 is meeting projections, while ridership on Rte. 4 is less than predicted. Expansion is being considered to connect the Northeast Kingdom to the national intercity bus routes. The challenges for the NEK intercity service are balancing the potential ridership, given the low population, with the investment that is needed, and with fitting the right type of service to such a rural area. Planning for the design of such service continues. Additional marketing changes are being analyzed to increase the ridership on all services.

8.5.3 Go Vermont, Rideshare, Vanpool, and Car Sharing

Travelers are increasingly demanding easy-to-navigate tools and information to help with their transportation choices. *Go Vermont*[154] is a free online public service sponsored by VTrans that provides ride share, vanpool, public transit, and Park and Ride matches in seconds. It also serves as a web-based clearinghouse for Vermont's alternative transportation programs.

There are currently 3,685 registered users in the Go Vermont carpooling program. The average distance for Go Vermont users' trips to and from their worksite is 45.2 miles. Assuming that 20%[155] of the registrants are participating in a carpool, vanpool, or public transit route, the program has resulted in the

[154] www.connectingcommuters.org/

[155] This is the national average calculated by the software provider.

reduction of more than 9.6 million VMT, savings of $5.2 million in commuting costs, and avoidance of 1.6 million pounds of CO_2 emissions.

The Go Vermont program also subsidizes vanpools for up to $700 per month per vanpool, to offset the per-seat costs of its participants. Participants pay between $60 and $100 per month and enjoy saving more than 60% on their daily commute.

Along with offering the vanpool program, Go Vermont staff began working with businesses in 2011. Their efforts focus on communicating directly with employers and employees to promote awareness of commuting options, and helping to set up programs for those who would like to save money and reduce their environmental footprint.

Go Vermont also subsidizes the annual Way to Go Challenge and other events that have raised public awareness of and commitment to reducing single-occupancy vehicle travel, and reducing energy use and GHG emissions.

Car sharing is a neighborhood-based, short-term rental service that makes vehicles available on a per-use basis. In 2008, CarShare Vermont launched in Burlington. A recent study of North American car-sharing organizations conducted by the Mineta Transportation Institute shows that households that participate in a car-sharing program reduce their emissions by 0.82 tons per year, and reduce their driving by 40% to 60%. Further, each shared vehicle put into circulation is shown to remove an average of 13 from the road as people opt to shed excess vehicles. CarShare Vermont cites a number of individual and community benefits, including GHG reductions, cost savings, reduced traffic congestion, better land use, increased use of alternative transportation, and social equity.[156]

Recommendations

(1) Expand the Go Vermont website and increase its use for events.

(2) Research a state pilot program for parking cash-outs to decrease single occupancy vehicle commuting.

(3) Continue supporting employer programs to encourage carpooling, vanpooling transit, walking, and biking for employees' commute trips.

(4) Continually investigate software and other technology improvements to make taking transit easier and increase rideshare, vanpool, carshare, and other options.

8.5.4 Park and Rides

Park and Ride lots facilitate ridesharing and transit use by providing a safe place for travelers to leave their cars and meet each other or the bus. There are 27 state Park and Ride lots in Vermont, encompassing

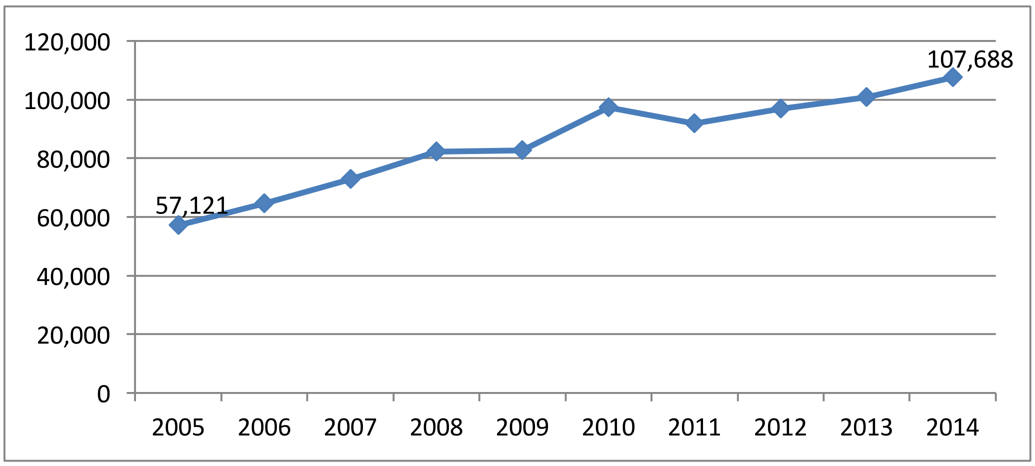
[156] CarShare Vermont, *Why Own When You Can Share?*, www.carsharevt.org/why-share/

1,380 spaces (representing an average increase of 60 spaces per year since 2011). In addition, dozens of municipal lots are located throughout the state, many of which have been supported by the popular state municipal Park and Ride program; and there are many more informal places where drivers meet to ride-share. VTrans will continue funding park and rides at a level adequate to meet CEP objectives.

8.5.5 Passenger Rail

Since 2006, intercity passenger rail trips in Vermont have increased by 60% to more than 97,000 per year. Vermont was recently awarded a $52.7 million Federal Railroad Administration high-speed and intercity passenger rail (HSIPR) grant to improve track speeds to 59-79 mph along the Vermonter route.

Exhibit 8-9. Rail Ridership at Vermont Stations, 2005-2014



Source: Amtrak

The Ethan Allen Express provides daily round-trip service from New York City to Rutland by way of Albany, N.Y. The Vermonter provides daily service from Washington, D.C. to St. Albans, offering connections to Baltimore, Philadelphia, and New York. One southbound and one northbound trip are provided each day. Other stops within Vermont include Essex Junction, Waterbury, Montpelier, Randolph, White River Junction, Windsor, Bellows Falls, and Brattleboro.

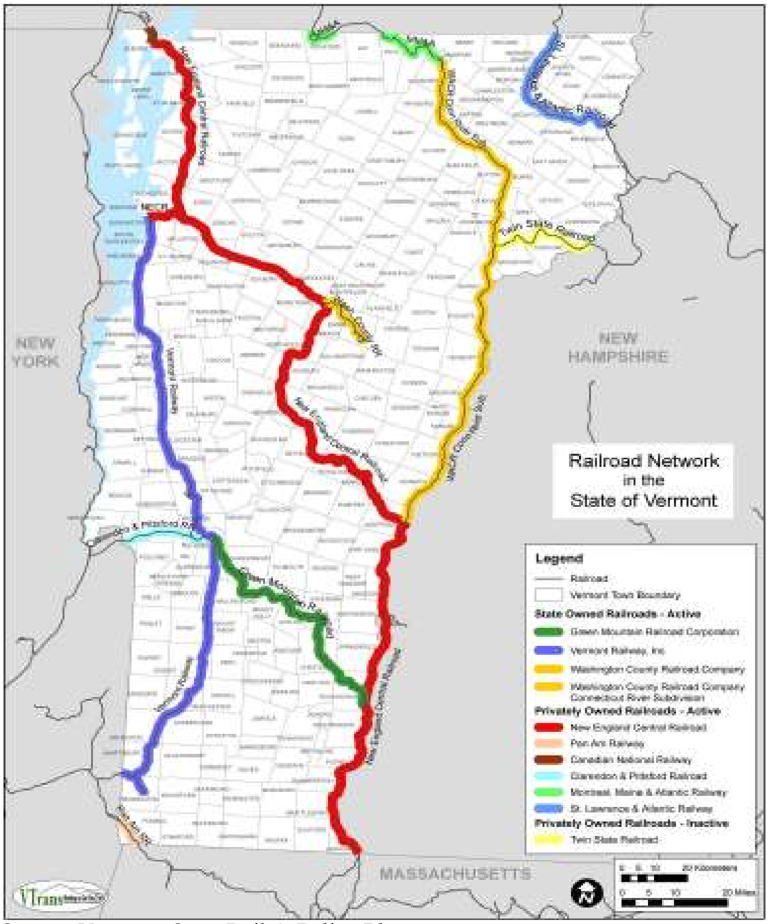
Recommendation

Continue state efforts to extend the Ethan Allen service from Rutland to Burlington and bring the Vermonter service to Montreal.

8.5.6 Freight Rail

Freight rail is one of the most energy-efficient modes for moving goods. According to the Association of American Railroads, freight railroads can transport a short ton (2,000 lb.) approximately 436 miles on a gallon of fuel.[157] Vermont has a comprehensive freight rail network of approximately 749 miles, of which 453 miles are state-owned. Ten short lines and regional railroad companies are operating or have trackage rights in Vermont.

Exhibit 8-10. Vermont Railroad Network



Source: Vermont State Rail & Policy Plan

In 2011, 6.6 million tons of freight were transported from, to, and through Vermont by freight rail.[158] By 2035, total rail freight over Vermont's rail system is projected to increase by 57% to 10.4 million tons.

There are some challenges in increasing freight rail use. Most freight carried into or through Vermont originates out of state, is short-hauled on trucks, and is intended for use by private industry in wholesale and retail distribution systems called *just-in-time* delivery systems. Private industry owns much of the rail network in Vermont, and businesses' freight decisions are based on cost and timing.

Many of Vermont's railroad tracks and bridges have a weight limit of 263,000 pounds per railcar, while nationwide the industry standard is 286,000 pounds. To meet the required weight limit, some Vermont

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[157] Association of American Railroads, *Sustainability*, www.aar.org/todays-railroads/sustainability

[158] Agency of Transportation, *Vermont State Rail Plan — 2015* (June 19, 2015 draft), vtrans.vermont.gov/sites/aot/files/VT State Rail Plan Draft June 2015.pdf

customers have to "light load" their railcars, meaning they are not loaded to capacity. Also, many bridges across the state are in need of rehabilitation, and a number need modification to allow for proper height clearance so railroad cars can be double-stacked. The current Draft Rail Plan estimates a need of $203.7 million to bring bridges along the state-owned rail lines to 286,000 lbs. railcar loading.

These infrastructure limitations have received considerable attention from the U.S. Department of Transportation in the last several years; as a result, passenger-rail operating speeds are now 59-79 mph along the entire Vermont portion of the Vermonter route, and work is ongoing to ensure a continuous 286,000-pound service from St. Albans to Connecticut.

8.5.7 Active Transportation — Biking and Walking

Biking and walking do not require petroleum or other energy sources, and have health and quality-of-life benefits. Access to walking and biking also contributes to the economic vitality of downtowns, outdoor recreation opportunities, and the tourist economy. Biking and walking are largely dependent on a complex network of trails, paths, sidewalks, and roads. This infrastructure network ranges from primitive trails on private or public property, to municipally maintained sidewalks and shared-use paths, to paved shoulders on both state and local roads.

The state supports biking and walking infrastructure in several ways. The VTrans Local Projects section provides grants to municipalities for bike and pedestrian infrastructure improvements. The state makes paving and other safety improvements to Vermont's roadway network, to make trips smoother and safer for cyclists and pedestrians as well as vehicles. *Complete streets* is a concept whereby transportation planning and design safely accommodate motorists, bicyclists, public transportation users, and pedestrians of all ages and abilities. Complete Streets legislation, passed in 2011, requires that the planning and construction of state and local transportation projects either consider Complete Streets principles or document why it is not feasible to do so.

The Vermont Department of Health has provided grants that help community coalitions improve access to places where Vermonters and visitors can be physically active, including bicycle and pedestrian facilities. These funds have also been used to educate and mobilize local communities for small projects, such as improved signage, bicycle racks, and crosswalk improvements. The Department of Health's Offices of Local Health continue to provide support, as needed, for municipalities' active transportation projects.

Active transport tendencies of Vermonters, shown in the table below, were taken from the 2009 NHTS data. Of the nearly 10,800 unique trips recorded from the Vermont 2009 NHTS data set, 39% are less than 2 miles and 28% are less than one mile. Of all trips of length under two miles, roughly 87% percent were made by motor vehicle. Given the national average bicycling trip length of two miles and walking trips of one mile, many of these short trips have the potential to be shifted from SOV to either walking or bicycling.

Exhibit 8-11. Vermonters' and Nationwide Biking and Walking Tendencies, 2009

Number of Trips in the Past Week	Vermonters		Nationwide	
	Bike	Walk	Bike	Walk
0	85.4%	24.6%	87.2%	32.1%
1-2	6.9%	16.9%	8.2%	16.2%
3-5	4.2%	26.3%	4.4%	24.1%
5+	3.6%	31.6%	2.2%	26.6%
	100%	100%	100%	100%

Source: USDOT, 2010

Safety concerns present a major challenge in encouraging more Vermonters to walk or bicycle. Many roads in Vermont do not have bike lanes, adequate shoulders, sidewalks, or safe crossing opportunities. Even where these facilities do exist, pedestrians and bicyclists may not feel safe sharing roads with motor vehicles, especially where those are traveling at high speeds. Hilly topography and inclement weather are also significant barriers.

Ongoing recommendations to address these challenges include a continued focus on education of all road users, and continued funding of infrastructure projects with an emphasis on addressing safety concerns and completing bicycling and walking networks. Design treatments to provide greater separation between bicyclists and adjacent traffic have been shown to both increase safety and make people more likely to try bicycling. Traffic-calming and road or streetscape modifications can also slow motor vehicle traffic. Compact development patterns help reduce travel distances and make walking and biking more attractive options. Even for those who live too far away to reasonably walk or bike to work, working in a compact community allows for mid-day trips to be made on foot or by bike.

While the Complete Streets legislation has raised awareness about the concept, there is a need for continued education at both the state and local level to ensure that the concept translates into action.

8.5.8 Telecommuting and Remote Conferencing

Telecommuting is a work arrangement that gives employees flexibility in where they work. Many choose to work from home, others from other locations. A survey conducted by the DPS in 2014, however, showed that only 13% of respondents telecommuted every day and that 53% never telecommuted.

The state is working to increase the telecommunications infrastructure that is necessary to expand opportunities for telecommuting throughout the state. For over a decade, the state has recognized the need for the universal availability of advanced telecommunications services as critical to Vermont's economy and culture. Broadband can increase worker productivity by offering remote access to information, and can provide additional opportunities to work remotely, whether at home or in the field. These productivity gains can help reduce Vermonters' transportation needs.

At the end of 2013, every Vermont E-911 residential and business location had availability of high-speed internet access (defined as a connection of at least 768/200 Kbps), or had a funded solution in place. Having met the goal of bringing high-speed internet access to every Vermonter, the state has turned to improving those connections. In 2014 it set a goal of supporting measures designed to deploy infrastructure that can support connections with 100 megabits per second (Mbps) symmetrical by 2024. As the quality of Vermonters' broadband connections improve, the opportunities for telecommuting may also increase.

High-speed Internet access is necessary to promote telecommuting, but it is not enough. Businesses must educate managers about the benefits of telecommuting; improve the ability of managers and employees to use technologies for ensuring continuity of office functions such as remote-meeting software and equipment; and develop methods for ensuring accountability and productivity. To promote telecommuting as a way to reduce driving, the state and private employers must overcome these not-insignificant hurdles.

8.6 Alternative Transportation Fuel Sources and Vehicles

Transitioning Vermont's transportation from a heavy dependence on fossil fuels toward a reliance on cleaner, renewable electricity and more renewable fuels is a key pathway to a new sustainable energy future. Since transportation fuels account for the single-largest portion of Vermont's total energy consumption, and fossil fuels are the main source of that energy, Vermont cannot meet its energy goals without a transformation in how we power our vehicles. Likewise, meeting aggressive state goals for reducing the state's contribution to global GHGs will necessitate major changes in the vehicle fleet.

Transforming the efficiency of vehicles in Vermont is an economic as well as an environmental imperative. At today's low gasoline prices, Vermonters currently spend around $750 million per year on gasoline for light-duty transportation. Hypothetically, if all cars and light trucks were replaced by electric vehicles overnight, the resulting annual fuel expenditure would fall almost in half, to about $385 million. In addition to keeping more energy dollars local (electricity is produced locally, unlike gasoline), this transition would reduce fuel costs by $365 million per year. These savings would increase if gasoline prices rise.

First and foremost, the state should work on reducing vehicle miles traveled by encouraging shifts in transportation modes, supporting land use strategies that promote compact growth and through the other strategies identified above. To complement those efforts and put the state on a path to meeting its climate and energy goals, there must be a significant expansion in the number of light-duty electric vehicles on Vermont's roads, a transition that will significantly increase the efficiency of the statewide fleet and replace fossil fuel with renewable sources. Improving the average efficiency of the fleet by encouraging consumers who are not willing or able to purchase electric vehicles to purchase the most fuel-efficient conventional vehicles available will also be critical in the next five years.

In October 2015 there were 1,129 electric vehicles registered in Vermont, including plug-in hybrid vehicles (PHEVS) and all-electric vehicles (AEVs) that run only on electricity. This is a small fraction of the approximately 550,000 passenger vehicles currently registered (a total which includes SUVs, vans, and light-duty trucks as well as passenger cars). However, there has been a steady rate of increase in electric vehicle sales since the last CEP in 2011; and with many new and improved electric vehicle models soon to be introduced to the national automobile market, there is real opportunity to substantially grow the electric vehicle market during the six-year period of this plan.

Increasing the use of liquid biofuels in certain areas of Vermont's transportation sector can also support the state's efforts to reduce vehicles' environmental impact. Biofuels can be especially useful for improving vehicles' impact where electric technologies are not yet readily available, such as in heavy-duty fleets used to transport cargo. They may also provide a good alternative way to fuel vehicles that perform specific on-site functions, such as agricultural or forestry work. Their use in these applications can be increased without any new investments in specialized vehicles, equipment, or infrastructure.

Many factors shape the number, type, and relative efficiency of the vehicles registered in Vermont: federal and state vehicle efficiency standards, the development and sale of new technologies (such as batteries that can increase EV range), the diversity and quantity of vehicles available in new and used markets, the price of gasoline or other fossil fuels, consumer preferences, and evolving consumer knowledge about vehicle technologies. While the pace of the transformation of vehicle markets is a complex process driven by many factors, the market for electric vehicles is still very new, and state government and partner organizations can play a critical role in spurring its growth by developing supportive policies and programs that both increase consumer awareness and demand and ensure adequate supply of new technologies and models in the Vermont vehicle marketplace.

This section proposes a set of strategies and recommendations that can quicken the pace of the electrification of the transportation sector and the transition to greater use of biofuels in heavy-duty fleets, public transit, and specialized uses. The section begins by reviewing key elements of the policy and regulatory context governing vehicle emissions, including existing federal regulations for GHG emissions and average fuel efficiency, and state requirements governing the availability of advanced vehicle technologies. It then focuses on the range of benefits expected from the electrification of passenger vehicles, and describes the actions needed to facilitate the transition. Specifically, it:

- Describes the state's participation in a Multi-State Zero Emission Vehicle Task Force composed of eight New England and Western states, and its development of a ZEV action plan for Vermont; and

- Provides the highest-priority strategies and recommendations for increasing the share of electric vehicles in Vermont's fleet over the next six years.

The latter half of this section on cleaner vehicles and alternative fuels focuses on recommended approaches to increase the targeted use of biofuels. It:

- Presents a brief overview of the range of biofuels available and their particular uses and applications;
- Reviews the evolution of federal and state regulations governing the sale and distribution of biofuels; and
- Provides the highest-priority recommendations for increasing Vermont's use of biofuels in those areas of the transportation sector where electrification is a less feasible or affordable alternative.

8.6.1 Federal Emissions and Fuel Economy Standards

Federal policy is helping push market changes that decrease petroleum consumption and emissions. The U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) jointly regulate vehicle GHG emissions and fuel economy. EPA has established national GHG emissions standards under the Clean Air Act, and NHTSA has set Corporate Average Fuel Economy (CAFE) standards under the Energy Policy and Conservation Act, as amended by the Energy Independence and Security Act (EISA). CAFE standards set fuel economy requirements for classes of vehicles sold by vehicle manufacturers.

The most recent revisions to these standards for passenger cars and light-duty trucks are projected to result in an average industry fleet-wide level of 163 grams/mile of carbon dioxide (CO_2) in model year 2025, which is equivalent to 54.5 miles per gallon if achieved exclusively through fuel economy improvements. In addition, CAFE standards for medium and heavy duty vehicles are currently being established by EPA, and will provide a major impetus to the improvement of engine technologies that improve fuel efficiency in trucks.

Because states are pre-empted by the federal government from setting their own fuel economy and GHG standards, Vermont's options for increasing the average efficiency of vehicles registered in this state are limited. However, Vermont can monitor average fleet efficiency and can implement non-regulatory strategies to promote the purchase of the most fuel-efficient vehicles available.

8.6.2 Vermont's Low-Emission Vehicle Program

Vermont has a long history of regulating automobile emissions to the greatest extent allowable under federal law. Under the federal Clean Air Act, the state has the option of either accepting the U.S. EPA's motor vehicle emissions standards or adopting those of California. Vermont first adopted California's vehicle emissions standards in 1996, because they were more stringent than the EPA's program.

Initially, Vermont established a low-emission vehicle program to reduce smog-forming emissions and to stay in compliance with the National Ambient Air Quality Standards. Since then, the state has amended its LEV rules periodically to remain consistent with California's rules. Subsequent amendments have included adoption of California's zero emission vehicle (ZEV) requirements and GHG emissions standards — both of which are significant elements of Vermont's climate change mitigation strategy, given that motor vehicles are the greatest source of GHG emissions in Vermont.

Most of the northeastern states have also elected to adopt California's standards, as part of a regional effort to reduce air pollution and help mitigate climate change. The California vehicle emission standards, which apply to new vehicles sold in Vermont and the other states that have adopted the standards, have helped spur technological developments, resulting in plug-in hybrid electric, all-electric, and hydrogen fuel-cell vehicles, as well as continuing advancements in significantly cleaner internal combustion engines.

8.6.3 Reasons to Boost the EV Light-Duty Market

As noted above, achieving significant reductions of GHG emissions and fossil fuel consumption in Vermont's transportation sector will require a large-scale transformation to alternatively fueled vehicles that reduce petroleum usage and related emissions with advanced technologies and fuels (such as plug-in hybrid electric vehicles, all-electric vehicles, and fuel-cell electric vehicles). Indeed, Vermont's 2011 CEP identified vehicle electrification as a primary pathway to enable the state to meet its renewable energy goal, and set an objective to have 25% of vehicles registered in the state powered by renewable sources by 2030.

Vermont's primary focus in the last five years has been on promoting the development of the market for PHEVs and AEVs. This is because fuel-cell electric vehicles (FCEVs) are earlier in their development, with just a few models currently available nationally and none being sold yet in Vermont. Also, building the infrastructure to provide for convenient fueling of fuel-cell vehicles by hydrogen fuels would take considerable time (there are no hydrogen fueling stations within the state at present), and would involve a level of capital investment that may not be achievable, at least in the near future, in this rural state.

Widespread adoption of electric vehicles in Vermont will advance multiple state priorities: protecting public health and the environment by reducing transportation-related air pollution and GHG emissions, enhancing energy diversity, saving consumers money, and promoting economic growth.

EVs operating in the electric mode have no direct emissions. The overall air quality and GHG benefits of ZEVs compared to conventional gasoline and diesel vehicles are a function of the source of the electricity or hydrogen they use as fuel. Vermont has very clean sources of electricity — so even when you take into account the emissions associated with the generation and distribution of the fuel used to power the vehicles, electric vehicles outperform even the best gasoline hybrids. Moreover, when powered by renewable resources such as solar power, the total emissions from operating an all-electric vehicle are nearly zero. Thus, Vermont's efforts to increase renewable energy sources of electricity will further increase the environmental and public health benefits of electric vehicles over time.

EVs can also help reduce the cost of living for Vermonters and the cost of doing business here. The typical driver of a conventional gasoline-burning passenger vehicle spends about $700 to $1,800 per year on fuel to travel an annual distance of 10,000 to 12,000 miles[159]. The same number of miles can be driven in an electric-powered passenger vehicle at an annual fuel cost of around $500 to $900, nearly half the amount as for a conventional passenger vehicle[160]. Hypothetically, if all cars and light trucks were replaced by electric vehicles overnight, the resulting statewide annual fuel expenditure would fall almost in half, from about $750 million to about $385 million. These savings would increase if gasoline prices rise from their current low levels.

Finally, the Zero Emissions Vehicle program adopted by California and by other states — including Vermont — recognizes that regulations governing the sale of electric vehicles are *technology forcing*. As these vehicles are being developed and sold by auto manufacturers, the research and development performed to develop new models is supporting the development of more fuel-efficient conventional vehicles. The evolution of market demand for EVs will over time also shift general consumer preferences toward vehicles that perform well on efficiency.

8.6.4 Today's EV Market

According to the Department of Motor Vehicles, the number of passenger electric vehicles registered in Vermont (including plug-in hybrids and all-electric passenger cars) in October 2015 was 1,046. The total of other electric vehicles, such as motorcycles and mopeds, was 83 (these figures do not include electric-assist bicycles, which are growing in popularity in many countries and slowly in Vermont and other U.S states.) The 1,129 total electric vehicles registered in Vermont represent a 31% increase from 12 months before. Vermonters across the state have been purchasing new models, and more than 16 are currently available for sale in dealerships. Leasing EVs has also increased in popularity.

As of October 2015, EVs were registered in 66% of Vermont municipalities, with Chittenden County showing the most at 362, and Lamoille Country showing the highest rate of ownership with about one EV for every 300 people. Exhibit 8-12 shows where they are registered, the range of vehicles being registered, and the breakdown of makes and models statewide. As the number of electric vehicles on Vermont roads has risen, the availability of electric charging infrastructure has also increased. This includes public charging infrastructure in downtown locations and at Park and Rides, as well as infrastructure at workplaces and in homes.

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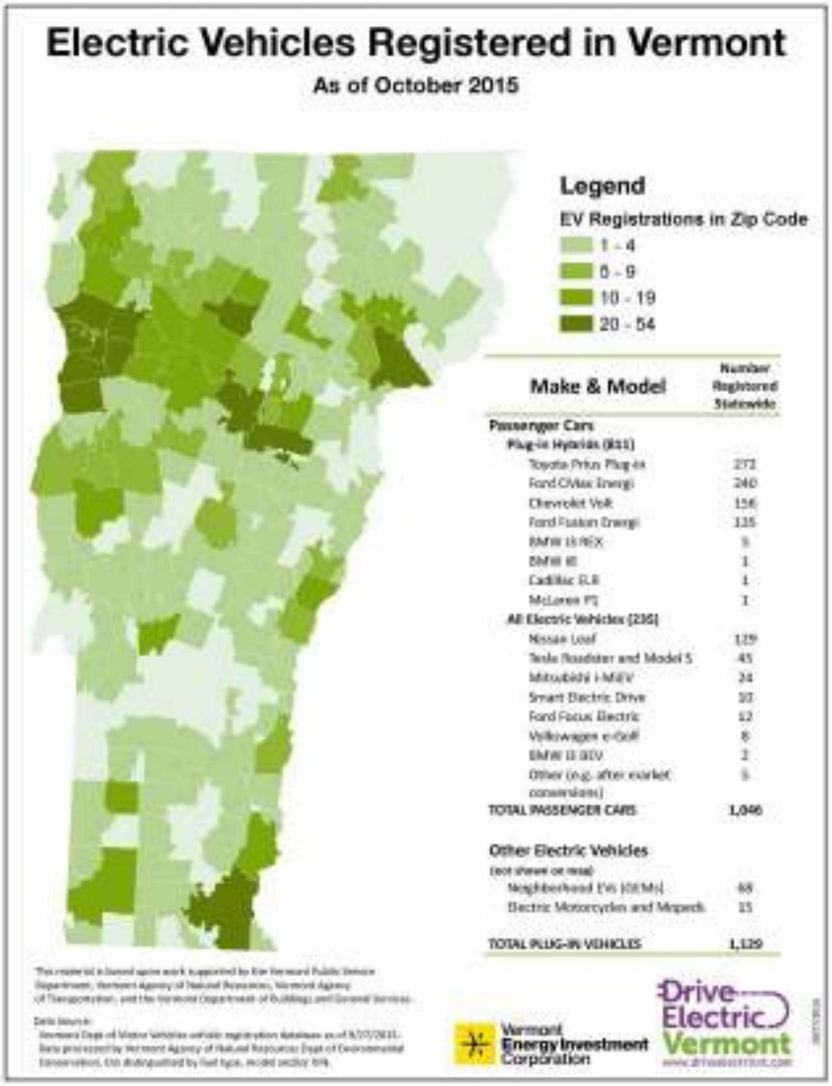
[159] Calculation assumes a range in vehicle fuel efficiency of 20 to 30 miles per gallon and a range in the price of gasoline of $2.10 to $3.00 per gallon.

[160] Calculation assumes a range in electric vehicle efficiency of two to three miles per kilowatt-hour and a retail price of electricity of 15 cents per kilowatt-hour.

Exhibit 8-12. Distribution of Electric Vehicle Registrations in Vermont



The number of electric vehicles sold each year in Vermont has grown dramatically since 2012, when the Department of Motor Vehicles and the Agency of Natural Resources began reporting sales figures, from less than 100 cars to over 1,000. The market share of electric vehicles has also increased and currently hovers around 1.5%, still a very small percentage of all passenger vehicles sold.

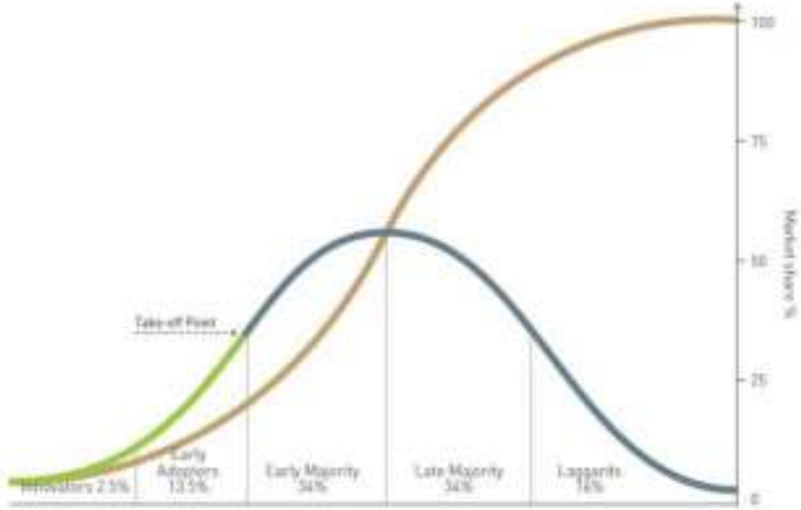
Exhibit 8-13. Passenger Electric Vehicle Registrations Grew from 88 in July 2012 to 1,046 in October 2015

Source: DMV and VEIC

The EV market in Vermont is still at a very early stage of development. Innovation diffusion theory, first developed in 1962 by sociologist Everett Rogers, explains how populations adopt a new technology—very slowly at first as "innovators" and then "early adopters" begin using it, and then more rapidly as markets reach a tipping point and the new technology is adopted by an "early majority" (Exhibit 8-14). In Vermont, where only 1.5% of new vehicle sales are electric vehicles, their reach has not yet extended past innovators to early adopters (Exhibit 8-14). The reasons for this are discussed below, and include the fact that electric vehicles are a very new technology, and that there is limited public awareness of EVs and their benefits and limited inventory of current makes and models available in the state's auto dealerships.

The state's current goals for transforming the fleet and developing a sustainable market require an annual 30% growth rate in EV sales from 2016 to 2025, until new sales reach about 4,600 vehicles per year. At this point the market should transition to a more mature and sustainable phase, and many Vermonters will choose a plug-in hybrid or all-electric model when shopping for a new or used vehicle.

Exhibit 8-14. Innovation Diffusion, Illustrated



Source: Wikipedia[161]

Before the EV market reaches that take-off point, state government can play an important supportive role by adopting and supporting policies that encourage consumers to purchase or lease electric vehicles and remove obstacles to market growth, by promoting the development of charging infrastructure, and by raising awareness about the benefits of the new technology. Nonprofit organizations, utilities, and business partners committed to EV technology can also offer significant assistance that will help move it into the mainstream.

Vermont made an early commitment to electric vehicles when the state decided to adopt California's Low Emissions Vehicle Program, including the set of regulations governing the sales of electric vehicles. Vermont also joined a formal collaboration with seven other northeastern and western states equally intent on electrifying their transportation sectors.

8.6.5 Multi-State ZEV Task Force and Vermont ZEV Plan

The Agency of Natural Resources administers the state's Low Emissions Vehicle Program. In this role the agency oversees specific program requirements related to the sale of zero-emission electric vehicles in Vermont. The regulations require auto manufacturers to meet sales targets for electric vehicles on a designated time frame. In the year 2018, these requirements scale up considerably.

While the ZEV regulations are a key part of Vermont's approach to supporting the development of a robust electric vehicle market in the state, regulations alone are not enough to support this market evolution. California's state government works closely with private and nonprofit partners to support the

[161] en.wikipedia.org/wiki/Everett_Rogers

development of EV market demand with public outreach and education, supportive policies, and financial incentives for purchasing EVs and charging infrastructure. The goal is to ensure that market demand evolves quickly, enabling auto manufacturers to achieve compliance and to profit from the new sales so that the market is sustainable. California has demonstrated that EV-friendly policies and investments make a difference — there are now more than 100,000 EVs registered in the state[162].

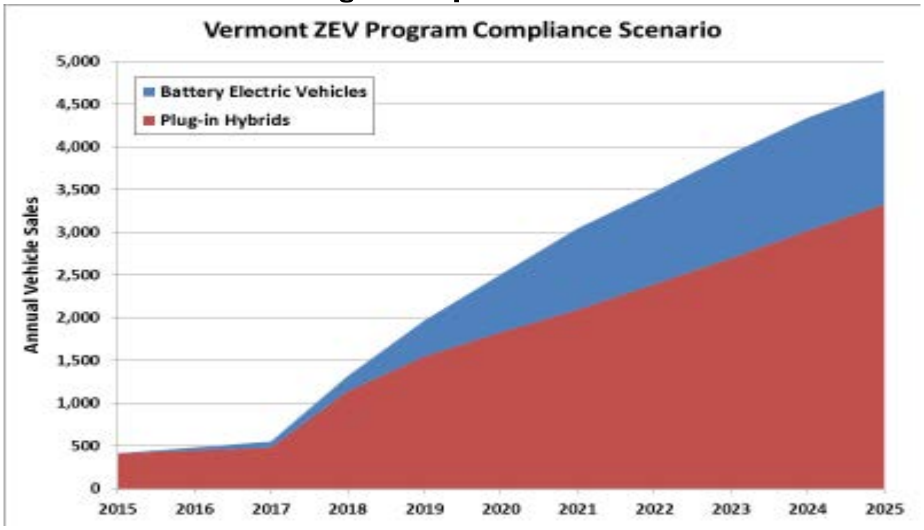
On October 24, 2013, the governors of California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont signed a memorandum of understanding (MOU) committing to coordinated action to ensure the successful implementation of their state ZEV programs. Collectively, these states are committed to having at least 3.3 million electric vehicles operating on their roadways by 2025. The ZEV MOU identifies joint cooperative actions the signatory states will undertake, and additional actions that individual jurisdictions are considering, to build a robust market.

Pursuant to a directive in the MOU, a multi-state ZEV Program Implementation Task Force was formed to improve regional collaboration. Its first action was to publish a Multi-State ZEV Action Plan designed to guide interstate coordination and inform state-specific action to accomplish the goals of the ZEV MOU. It is not intended to provide a uniform pathway for all states to follow. In 2014, Vermont's Climate Cabinet released a Vermont ZEV Action Plan, identifying strategies and actions that best address Vermont's own needs and our unique opportunities to achieve the commitments made by Governor Shumlin in the ZEV MOU.

The plan includes one projected scenario for growth in Vermont's electric vehicles sales that would achieve the state's share of the regional goal in the Multi-State MOU, and that would align with automaker compliance with the ZEV regulations. It suggests that annual sales of electric vehicles (plug-in hybrid and all-electric) will need to reach 4,600 by 2025, about 15% of the total annual sales of vehicles in the state each year (Exhibit 8-15). This goal aligns with the CEP's objective of making 10% of the state's fleet EVs by 2025.

[162] California Plug-In Electric Vehicle Collaborative, *2014 Annual Report*, www.pevcollaborative.org/sites/all/themes/pev/files/CPEV_annual_report_web.pdf

Exhibit 8-15. Vermont ZEV Program Compliance Scenario



Source: ANR

The multi-state task force created by the ZEV MOU will serve as an ongoing forum for coordination and collaboration to ensure effective and efficient implementation of our state ZEV programs. As we have seen through other multi-state initiatives, such as the Regional Greenhouse Gas Initiative, collaborating with other states enables us to achieve results we could not achieve through individual state action.

Vermont's plan[163] includes 11 priority strategies, with recommendations under each. It makes recommendations for the state's use of EVs in its own operations, new policies, and programs that could support further development of the market, and ways in which partners such as the Drive Electric Vermont coalition, formed in 2012, can help achieve plan goals.

8.6.6 Challenges and Opportunities

8.6.6.1 Recent Progress

There has been a considerable increase in the number EVs on our roads since the 2011 CEP was released. Sales of new electric vehicles — including plug-in hybrids and all-electric vehicles — have steadily increased in this period. From October 2012 through October 2015, the number of plug-in passenger car registrations went from 120 to 1,046; and the number of Vermont communities with EVs more than tripled, to over 150.

The multi-state task force and ZEV action plan have identified priorities and steps for actively supporting the growth of a regional market that still represents a tiny fraction of all light-duty vehicles sold (less than 2% in all task force states). Vermont's own action plan creates a clear road map for how state agencies can

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[163] Vermont Climate Cabinet, *Vermont Zero Emission Vehicle Action Plan* (September 2014), anr.vermont.gov/sites/anr/files/specialtopics/climate/documents/ZEV/FinalVTZEVActionPlan_080114.pdf

work together, and with private and non-profit partners, to develop the policies and infrastructure necessary to support evolving light-duty EV technologies, and to support the growth of market demand beyond a small group of early adopters.

The launch of Drive Electric Vermont (DEV) has also positioned the state to support a more rapid acceleration of market demand than would be likely without such a forum. Founded in 2012 through the adoption of a Memorandum of Agreement between the state and the Vermont Efficiency Investment Corporation (VEIC), DEV engages stakeholders from electric utilities, automobile dealerships, and regional planning organizations, along with state and local government representatives, to facilitate the adoption of electric vehicles across Vermont. VEIC coordinates the coalition. Many other states in the multi-state task force are following Vermont's lead and developing their own EV stakeholder partnerships.

DEV is a well-organized champion for meeting Vermont's EV goals as quickly as possible, and can leverage efforts across multiple organizations in pursuit of those goals. Stakeholders gather quarterly and additional working groups meet more frequently. DEV hosts and participates in events around the state, to educate Vermonters about electric vehicle technology and its benefits to our transportation sector. DEV also seeks to boost the adoption of EVs by:

- Offering programs and incentives to help Vermonters purchase and charge their electric vehicles;
- Providing guidance on charging-infrastructure growth opportunities and best practices; and
- Serving as an objective third-party resource that provides information to a range of external constituents — from local governments to Vermont residents — on buying an electric car in Vermont.

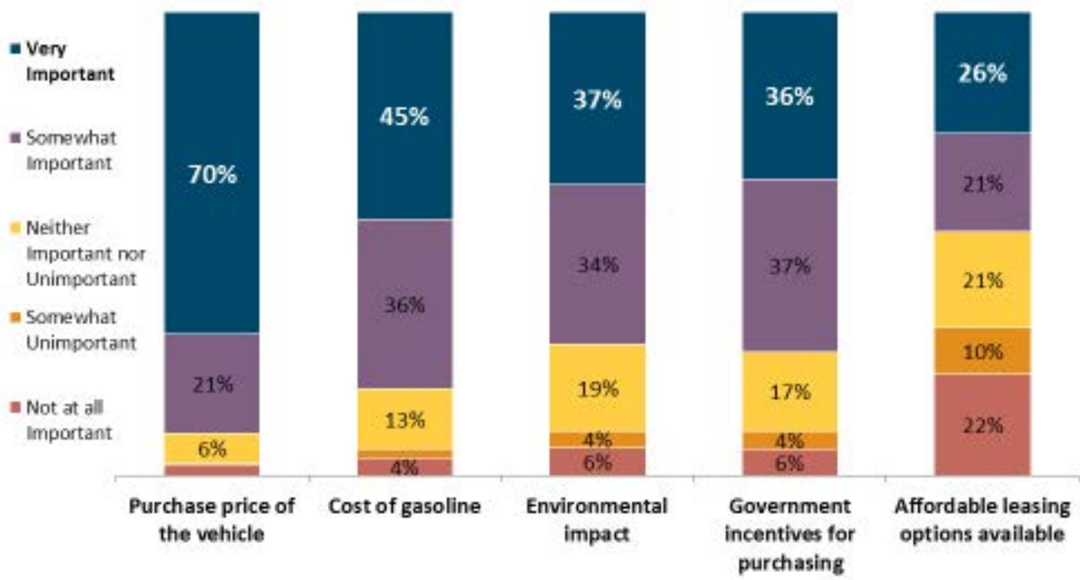
The development of the multi-state task force, the Vermont ZEV Action Plan and team, and Drive Electric Vermont create a strong organizational foundation for rapidly accelerating the adoption of electric vehicles and guiding the development of adequate infrastructure to support that transformation in the light-duty market. One of the biggest achievements in the last two years has been the increase in available public-charging infrastructure. As of December 2015, there are 99 EV charging stations displayed on DEV's map of public charging infrastructure in Vermont. Gains have also been made in the availability of workplace charging and the introduction of EVs into public and private fleets.

8.6.6.2 Limited Consumer Awareness and Interest

Despite these successes, there are significant challenges ahead for reaching a sustainable path of growth in the market, and we will need bold strategies and actions to overcome them.

The first challenge is the limited awareness among Vermonters of the benefits of owning and driving electric vehicles. A statistically valid survey of 495 Vermonters, performed by the MSR group in 2014, highlights the obstacles to building consumer interest. The survey suggests that over 90% of Vermonters have some general awareness of EVs, but many lack familiarity with their performance, their total cost of ownership, and the specific vehicle types and models that are available. Vehicle cost is the most common barrier respondents cited to considering EV purchases, followed by concerns over limited vehicle range and charging infrastructure.

Exhibit 8-16. Vermonters' Motivating Factors to Purchase an Electric Vehicle



Source: MSR Group, 2014

When asked what would motivate them to purchase an electric vehicle, purchase price was cited as the most important factor, with more than 90% of Vermonters surveyed identifying this as a very or somewhat important consideration. While the costs of new EV models are coming down as battery technologies improve and efficiencies are achieved from scaled-up production, the initial purchase price of most models is still higher than many popular conventional passenger cars. Compounding this challenge is the fact that a $7,500 federal income tax credit for purchasing new EVs will expire after automakers sell 200,000 vehicles. For leading manufacturers such as Nissan and Chevrolet, this limit could be reached in the next two to three years. It is unclear whether Congress will renew this tax incentive, which has been a pivotal support to the increases in consumer demand seen over the last several years.

8.6.6.3 Limited Supply of Vehicles and Caution among Dealerships

Since the 2011 CEP, auto manufacturers have introduced and begun marketing and distributing a variety of new light-duty vehicle models. They are all keenly aware of the scale-up in ZEV regulations that will occur in 2018 in states that have adopted California's Low Emissions Vehicle Program, and the associated requirements for the volume and timeline of electric vehicle sales. While these manufacturers vary in how they are planning to achieve compliance with the requirements, most are actively developing new EV models with a range of prices to spark consumer demand.

Sixteen unique models of plug-in cars are now registered in Vermont; in October 2015, 20 Vermont auto dealers had at least one new or used plug-in model in inventory. This represents significant progress over the last five years — but the availability of a diverse set of models that Vermonters can afford to lease or purchase is still very limited. Due to the "travel" provision built into the ZEV regulations, auto manufacturers can meet their fleet requirements by offering light-duty EVs for sale anywhere in the United States; there are no state-by-state requirements. This has led manufacturers to target states with the most developed EV markets for distribution of new models, principally California. States with earlier, less developed markets such as Vermont have seen fewer electric vehicles being distributed to dealerships, and smaller investments in marketing and outreach.

While this provision is set to expire in model year 2018 for all electric models, the "pooling" provision in the regulations will still allow manufacturers to comply with ZEV requirements by selling vehicles in any states that have adopted California's standards[164]. Auto manufacturers deciding where to distribute new EV models will look closely at evidence of market demand in these states, as well as the existence of supportive state policies such as consumer purchase incentives and incentives for installing charging infrastructure. Vermont's ability to ensure an adequate supply of the latest models in dealerships will depend, in part, on whether auto manufacturers are persuaded that we are on a pathway toward market expansion.

In Vermont, two other factors make it difficult to build the supply of EVs that are well suited to meet consumer preferences. First, even when auto manufacturers are interested in distributing new models here, dealerships are sometimes reluctant to carry them in their inventory due to uncertainty about how they will sell. This creates a chicken-or-egg problem: it is challenging to create adequate opportunities for Vermonters to learn about the cars if dealerships only carry a limited selection of models.

Second, Vermonters often buy used cars. There are almost no used plug-in hybrid electric vehicles, and no used all-electric vehicles, available in Vermont dealerships at present. As leased vehicles come off lease and become available to used-car distributors in the next year and beyond, Vermont can seek to develop a robust used EV market here — a step that will help to overcome the cost barriers to EV

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[164] These states are called "Section 177" states because they derive their authority to adopt California's standards for vehicle emissions under Section 177 of the Clean Air Act. Nine states have followed California's lead in requiring auto manufacturers to produce zero emission vehicles (ZEVs) to improve local air quality and reduce emissions contributing to climate change, including CT, ME, MD, MA, NJ, NY, OR, RI, and VT.

ownership and build the market segment that will appeal most with the kind of cars we like to drive and can afford.

8.6.7 Strategies and Recommendations

The next five years will be critical to getting the EV market in Vermont on a sustainable trajectory of growth. The Vermont ZEV Action Plan calls for 11 actions, and details many recommendations for achieving these action steps. The sections that follow present the three most important priorities for the next five years, as agreed by the state's Climate Cabinet and the DPS.

8.6.7.1 Catalyzing Market Demand with Incentives

As noted above, surveys of Vermonters show that cost considerations are likely both the principal barrier to wider interest in owning EVs, and a potential leverage point for increasing EV sales. The survey results show that most Vermonters know these kinds of cars are available, but they may lack awareness of their total cost of ownership — which can be lower than conventional vehicles, since the per-mile cost of traveling in an EV is less than the per-mile cost of using gasoline, and they require less maintenance. Further savings may be possible through the adoption of smart electric rates that take the time of vehicle charging into account. Electric rates are stable when compared to oil prices; this risk reduction also contributes to the financial difference between EVs and conventional vehicles.

Since the total cost of ownership can be lower than conventional vehicles, these vehicles can help to significantly lower transportation costs for the people who own and lease them. As a wider range of models at different costs become available in the next few years, EVs could bring significant economic benefits to middle- and lower-income Vermonters. The cost benefits increase the farther the distances traveled, so families living in rural areas would benefit substantially. These vehicles could also reduce exposure to air pollutants that cause respiratory and other health problems, especially in residential and commercial areas that are located adjacent to heavily used roads that experience traffic congestion.

Developing financial and non-financial incentives is a top recommendation of the Vermont ZEV Action Plan. Many European countries offer incentives — and in California, where over 100,000 EVs are registered and where market share for EVs has reached higher levels compared to other states, the Clean Vehicle Rebate Project has been effectively promoting the use and production of EVs since 2008. A number of other states have recently adopted EV incentives. Many of these programs have opted for rebates paid out immediately after the purchase of vehicles; others have opted for point-of-sale tax breaks or income tax credits. These programs are playing an important role in supporting the early phases of market transformation in their states by reducing up-front costs and encouraging early adopters to purchase or lease their first EV. Some of the states with the largest electric vehicle incentives —

California, Hawaii, Oregon, and Washington — have sales shares that are approximately two to four times the national average[165].

In Vermont, financial incentives in the form of tax breaks or rebates, or other kinds of incentives such as preferential parking, could help catalyze market demand among potential early adopters and help the EV market move into a phase of sustainable growth. These incentives would also increase interest among manufacturers and in-state auto dealerships in selling and actively marketing a diversity of models within the state.

Drive Electric Vermont recently ran a small incentive program that provided rebates of up to $500 to Vermonters who purchased a new vehicle, and incentive payments of $200 to dealerships that sold them. Funded by the Vermont Low Income Trust for Electricity (VLITE), this program has been extended for another year or two with consumer incentives of $750 and $1,000 (depending on battery capacity) and $200 dealer incentives. These incentives are relatively small in comparison to those offered by other states. Creating a new point-of-sale financial incentive at the state level — such as elimination of the purchase-and-use tax for EV transactions, or rebates — could generate considerably more interest, especially if applied to both new and used models.

Regional incentives could also be offered by electric utilities as a strategy for achieving requirements for Tier 3 investments under the Renewable Energy Standard approved by the Legislature in spring 2015. Any potential funding source should be evaluated with consideration of the other energy and climate solutions that could be funded with that source, along with the relative impacts and benefits of those options.

Local incentives might also be put into place by municipalities and private businesses. Many municipalities in California have sought to incentivize the adoption of electric vehicles by reducing the costs of parking them, and providing preferential access to parking when it's in short supply. These kinds of incentives, along with access to HOV lanes, are a key strategy for building the market.

Any kind of new incentive could be developed to meet a number of principles that have informed the design of incentives in other states:

Ensure access by those who can benefit the most, and for whom cost is a real barrier. Several states have structured eligibility for incentives to ensure that the benefits are targeted toward low- and moderate-income households. A common way to achieve this is by capping the program for income level or vehicle cost. In Vermont, where many households rely on used cars, incentives could be available for both new and used models.

Coordinate the timing for offering incentives and instituting fees with the stage of development in the market. Incentives that require public resources should only be used in the early stages of market

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[165] ICCT Report *Evaluation of State Level U.S. Electric Vehicle Incentives*

development; innovation diffusion theory suggests that once new technologies are sought by 15% of the potential users or consumers, markets can grow on their own. At the same time, budget planners concerned about dwindling transportation revenue as a result of more fuel-efficient cars have pointed out that electric vehicles running on electricity are not subject to the gas tax, and thus do not contribute to the state transportation fund in the same manner as conventional vehicles. The Vermont Legislature requested two studies (completed in 2012 and 2013) to examine this issue and recommend alternative-fuel vehicle user fees, including for electric vehicles. Both reports recognized that the state has conflicting goals. There is a need for users of the roadway to pay their share of public infrastructure upkeep, and it is also in the state's interest to actively promote electric-vehicle purchase and use because of the renewable energy and emissions benefits. State policies will be complimentary if user fees for EV ownership are phased in so that they do not inhibit early growth in the market, a phase during which consumers are just beginning to learn about EV technology and its benefits.

Create incentives that are understood at the point of sale. Experience in many states has shown that potential buyers of EVs are most responsive to incentives that are delivered during the transaction.

Make program administration as efficient as possible. To ensure that public resources devoted to incentives are targeted and efficient, there must be an organization responsible for managing the program efficiently. Organizations such as the Clean Energy Development Fund administered by the Public Service Department or Vermont's independent energy efficiency utility, Efficiency Vermont, could be considered. Another option is to hire a contractor; California, Connecticut, and Massachusetts have all chosen this path for administering their programs.

Recommendations

(1) *Evaluate options for incentivizing the purchase and lease of EVs in the early stage of Vermont's market development, including developing a statewide rebate or tax break for EV purchases, and/or encouraging utilities to develop regional incentives as they implement the new Renewable Energy Standard established by Act 56. Include in this evaluation consideration of the effects of different incentive strategies on different income groups, and coordinate it with efforts to identify new sources of transportation revenue to address declining gas tax revenues.*

(2) *Carefully structure and time the onset of any special fees for EV owners implemented to increase their contribution to the cost of maintaining state roads, so that the new fees do not inhibit growth in consumer demand and won't work at cross purposes with other state efforts to increase electric vehicle sales.*

(3) *Work with nonprofit partners such as VECAN and VLCT and private-sector organizations to encourage broader implementation of incentives, such as free or reduced parking costs for EV owners and preferential access to parking spaces limited in supply.*

8.6.7.2 Promoting Consumer Awareness of the Benefits of EVs and Fuel-Efficient Vehicles

While there are more EVs on Vermont's roads every year, there are still only just over 1,100 registered across 250 communities. This means that EVs are not often seen, and many Vermonters do not know someone who drives one. Even though there are numerous benefits of owning an EV — such as less exposure to air pollutants, an equivalent cost of travel at about $1.70 a gallon, and nearly no maintenance in the case of all-electric vehicles — very few Vermonters are considering EVs when they want to replace their vehicles.

State agencies can raise the profile of advanced technology vehicles such as EVs and other highly efficient models in a range of ways. State leaders can emphasize that the adoption of electric and more fuel-efficient vehicles is a critical pathway for achieving state energy goals. Agencies can also use their websites and other agency communications to explain the benefits of efficient light-duty vehicles, and can organize recognition and awards programs to call attention to the expanding market and its champions.

Nonprofit partners such as Drive Electric Vermont play a critical role in supporting effective social marketing to spread the word. As a stakeholder coalition, DEV has the ability to leverage its broad network to increase interest in these vehicles. At regular stakeholder meetings, the many organizations working toward this goal can identify ways to coordinate their outreach and education efforts and address gaps. DEV can also use a variety of media types and channels to disseminate information about new EV models and stories about Vermonters who have integrated electric vehicles into their lives and are strong supporters. Other nonprofit organizations such as the Energy Action Network can be key partners for this.

Utilities across the state can also play a role in raising general awareness about the benefits of electric vehicles, charging practices and equipment, and the importance of electrifying transportation as a critical pathway to achieving the state's climate and energy goals. Utilities are often considered trusted advisors by their customers, and have regular communication with them via bill inserts and other means. Auto dealerships are also a leverage point for building consumer interest and demand. These dealerships and the salespeople they employ are the midstream element of the auto value chain, and play a critical role in the consumer's process of deciding what to purchase.

National research and Vermont experience proves that auto dealers and salespeople who are well-trained and well-versed in electric vehicles have much greater success in selling them. While there are a few enthusiastic and informed dealerships that are actively educating potential customers about the vehicles and having considerable success in selling them, many dealerships are not yet bringing available electric models onto their lots. Other dealers have a limited selection on their lots, but they are not actively selling them; some consumers report having been advised by dealers not to pursue their interest in purchasing a plug-in model. Good training programs are needed to support dealerships in preparing their sales force.

Finally, as major institutions lead by example in the adoption of EVs and the installation of charging infrastructure, many more Vermonters will come into contact with the vehicles, learn about them, and take note of the implied vote of confidence in EVs by organizations they trust. As Vermont's third-largest employer, the state has a special role to play in leading by example. The Buildings and General Services Department, which manages the fleet pool, and other state agencies are collaborating to support rapid transformation of the state fleet. The State Agency Energy Plan (SAEP) identifies specific recommendations for expanding the use of visible EVs, identified by a common feature such as a small icon, and for building out charging facilities. The SAEP also recommends adopting strategies such as right-sizing fleets and ensuring that the most efficient vehicles possible are deployed for specific trips.

Recommendations

(1) The state should continue to lead by example by significantly increasing in its fleet both plug-in hybrid electric vehicles and all electric vehicles where appropriate given state transportation needs, and by identifying opportunities to inform other employers about progress on fleet transformation.

(2) State agencies should maintain funding support for Drive Electric Vermont, and should collaborate with DEV on social marketing that supports EV adoption, and on work to increase the availability of a wide array of new and used EVs for consumers to learn about and experience at dealerships and other locations. These efforts should aim to increase awareness of the full range of available options, including electro-assist bicycles, electric transit vehicles, and other rapidly evolving EV types and technologies that provide multiple public health and environmental benefits.

(3) High-visibility events and recognition/awards programs, such as the governor's annual environmental awards, should showcase Vermonters and Vermont organizations that are helping to propel the state's transition to electric vehicles, as well as other strategies for reducing the energy used in transportation.

8.6.7.3 Deploying Infrastructure at Workplaces and Key Public Locations

Electric charging infrastructure deployed at strategic locations is critical for reducing "range anxiety" among EV owners and those considering purchasing an EV, and for maximizing the electric miles driven in plug-in hybrid models. Most people who own or lease an EV will rely principally on home charging — but after home charging, workplace charging stations are the second most commonly used infrastructure. Charging at work is convenient and easy; and a U.S. DOE study has shown that employees whose workplaces provide charging infrastructure are 20 times more likely to own an EV than employees whose workplaces do not. This may be because workplaces with infrastructure act as virtual showrooms for the vehicles, making them visible, demonstrating how they work, and providing opportunities for people interested in them to interact directly with EV owners.

Increasing workplace charging is a key priority in Vermont's ZEV Action Plan. State agencies are working with Drive Electric Vermont, the Clean Cities Coalition, and other partners to encourage employers to install charging stations for their employees (also to increase electric vehicles in their fleets, and offer employees incentives to purchase or lease them). In October 2015, a new campaign to engage employers in making their workplaces EV-ready — called Drive the Dream Vermont — was launched with participation from 21 companies, hospitals, and educational institutions. The DPS also provided support from a Department of Energy grant to help the Vermont Clean Cities Coalition launch a Clean Cities Workplace Charging Incentive Program. The program offers funding in tiers, based on the type of charging station to help Vermont workplaces cover their installation costs.

Publically owned infrastructure in central locations will also help to familiarize Vermonters with EVs and increase range confidence. The number of public EV charging stations has increased rapidly in the last five years, aided by a state grant program that provides funds for installing infrastructure in designated downtowns. But even though 99 public charging stations are currently available, some areas of the state still have very few or none.

Recommendations

(1) *The state should partner with Drive Electric Vermont, the Vermont Clean Cities Coalition, and other organizations to promote the expansion of workplace charging, in particular by continuing funding for incentives that help employers cover the costs of installing infrastructure, by implementing the Drive the Dream Vermont campaign, and by celebrating and showcasing employer investments in EV-friendly workplaces.*

(2) *The state and its partners should promote and fund the installation of DC fast-charging infrastructure at locations strategically located along major travel corridors and in transit hubs such as Park and Rides. The state should continue work with other states through the Multi-State Task Force to address statutory obstacles to developing charging stations in federal rights of way.*

8.6.7.4 Assessing and Improving Average Fuel Efficiency in Vermont's Fleet

In Vermont, the average length of ownership for light-duty vehicles is nine years. The pace at which the state can achieve the electrification of light-duty vehicles will be constrained by the pace of turnover in the fleet.

In the transitional period, strategies to encourage the selection of highly fuel-efficient conventional vehicles, and to encourage more efficient driving habits (such as reducing driving speed, eliminating idling, and keeping vehicles well maintained), can have a dramatic impact on the energy used in daily transportation and the GHG and other air pollutants emitted.

The state gathers data about registrations of electric vehicles, but does not have methods for evaluating the efficiency of Vermont’s total light-duty fleet. Developing baseline data and tracking trends over time would enable state agencies and their partners to measure progress toward promoting greater efficiency through consumer choices when buying vehicles, and through greater adoption of practices long known to improve fuel economy. The latter is a set of actions that all Vermonters can take today, contributing to progress in meeting energy and climate goals, reducing air pollution that affects our communities, and saving money.

Financial incentives could spur greater average fuel efficiency. For example, fees charged at the time of registration can be structured so that more efficient vehicles receive an incentive or a rebate, or so that less efficient vehicles receive a higher fee. "Feebates" can be designed to be revenue-neutral, or they can be designed to raise revenue that in turn can be used to provide purchase incentives for plug-in hybrid and all-electric vehicles. Implementation of any financial incentive or disincentive would need to be designed to minimize or eliminate financial impacts on Vermonters who are least able to afford alternative technologies that are more expensive than conventional ones.

Recommendations

(1) *Identify options and develop methods for assessing progress over time in improving the fuel efficiency of vehicle transportation in Vermont.*

(2) *Evaluate potential strategies for promoting the purchase of more fuel-efficient vehicles and more fuel efficient driving and vehicle maintenance practices, such as expanding education and outreach through programs like Go Vermont, and establishing incentives using tools such as rebate and feebate programs.*

8.6.8 Alternative Fuels

While electrification for Vermont's light-duty fleet is a viable option, and some heavy-duty freight transportation needs can be met by shifting freight to rail, there are many heavy- and 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 are preferred over petroleum products.

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 any new investments in specialized vehicles, equipment, or infrastructure. Environmental concerns, including poor energy return on energy invested and questions about the climate-change impact associated with ethanol, make it a less attractive option for the state. (See the Liquid Biofuels section of Chapter 12 for a more detailed discussion of biofuels, including sustainability, commercial availability, price, and appropriate applications.) Compressed and liquefied natural gas also offer GHG savings above gasoline and diesel, but are currently a non-renewable resource. However, 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. See Chapter 13 for a more detailed discussion of natural gas, including market dynamics and environmental concerns.

Biodiesel

Biodiesel, a cleaner-burning renewable fuel, can be used on its own as a fuel or an additive for any petro-diesel equipment. In colder climates, special steps are needed to use biodiesel at 20% blends (B20) and higher — specifically, the use of cold-flow additives or fuel heaters. To avoid potential problems with biodiesel blends, a 5% biodiesel blend (B5) is often used in the winter months, a higher-biodiesel percentage blend in the summer. Biodiesel's greater lubricity can reduce wear on engines.

Over the past five years, the federal Renewable Fuel Standard program and the renewal of the federal biodiesel blenders' credit have dramatically boosted national production of biodiesel. The federal standard requires a minimum amount of biodiesel to be blended annually by refineries and importers. Obligated parties can either buy the biodiesel directly and blend it at the refinery level, or purchase renewable identification numbers (RINs) for biodiesel produced elsewhere. Refineries are not required to notify wholesale or retail buyers if the blend is B5 or less.

As the federal requirement for biodiesel production has increased, the price of RINs has been very high. This has stimulated a national biodiesel market even in the face of low diesel prices. Because the price for biodiesel plus the price of RINs has been higher than the wholesale price for diesel, it is likely that some biodiesel is being blended high in the supply chain at the refinery level.

Unfortunately there is no way to track how much biodiesel is being blended into diesel transportation fuel being sold in the state. Although biodiesel blends of B5 and below are likely being sold throughout Vermont, retail customers have no way to know that they are supporting biodiesel. Wholesale suppliers that sell to Vermont retail dealers do not know the blend of biodiesel that they receive, because upstream suppliers are not required to disclose that information. Because most blending happens at refineries, any efforts to improve reporting will need to come from the national level. Retail fuel dealers can use hand-held analyzers to determine the blend of fuel they are purchasing from wholesalers at any given time.

Labeled biodiesel is currently available from only two retail fueling stations. The initial cost of adding a separate tank (although that is not necessary if all fuel is blended), along with uncertainties in the siting and permitting process, can dissuade fuel dealers or private companies from adding biodiesel to their fuel options. Technical assistance describing handling, storing, and using biodiesel, along with a description of Vermont's permitting requirements, could help expand biodiesel refueling stations. A differential in the biodiesel fuel tax rate or a fuel-tank installation incentive could also encourage more dealers to offer biodiesel.

Farmers in Vermont produce a very limited amount of biodiesel locally from oilseed crops such as sunflower and canola. Biodiesel is generally produced on farms for on-farm energy use and for sale in the immediate market, and is not a primary farm product. Biodiesel from algae is in research and development; this technology is being tested for large commercial production and markets, which includes fueling on-road transportation. There is a great interest in helping Vermont farms become more sustainable and self-sufficient by increasing their ability to source their own energy through renewable resources. As of 2012, the average cost to produce biodiesel from oilseed crops grown on Vermont farms was $2.13 per gallon (this reflects all fixed and recurring costs). At current average retail diesel prices of

$2.66 per gallon, farmers would hardly break even producing biodiesel.[166] The economic incentives do not currently align for local biodiesel production in Vermont.

There are a number of barriers to the effort to increase demand for biodiesel in Vermont. Although the American Society for Testing and Materials (ASTM) designed a standard for pure biodiesel fuel-blend stock (D-6751) in 2001, equipment and vehicle manufacturers are in different stages of testing, review, and revision of their warranties and owner's manuals.[167] Most major manufacturers now permit the use of B20 blends (and lower percentage blends) under their equipment warranties, but guidelines and conditions vary. Some blends of B20 — especially those high in saturated fats, such as waste animal fats and palm oil — can gel in Vermont's wintery conditions. These inconsistencies and the potential to overstep the bounds of manufacturer warranties have led to consumer caution and uncertainty toward biodiesel blends in general.

<u>Ethanol</u>

Ethanol is ethyl alcohol, which can be blended with gasoline and used in any vehicle that uses regular gas. It is derived from the fermentation of agricultural products — such as corn, sugar, or grains — to form starch or sugar ethanol, or from the processing of agricultural wastes, grasses, or wood to produce cellulosic ethanol. In the U.S., most ethanol is starch ethanol derived from corn.

Ethanol can be blended up to 10% with gasoline to form E10, and used in any engine that takes regular gasoline. Because ethanol corrodes rubber fuel system parts, specialized adaptations (or flex fuel vehicles) are necessary for blends greater than 10%. Ethanol is suitable for use in light-duty transportation applications. In the U.S., 95% of gasoline is already an E10 blend, meaning the country is reaching what is called the *blend wall* — the maximum amount of ethanol that can be added to gasoline without significant changes to the light-duty fleet.

Ethanol can also be used in specially designed vehicles at higher blends, up to 85% ethanol and 15% gasoline. E-85 compatible vehicles (also called flex fuel vehicles) have special hoses, valves, fuel lines, and fuel tanks that resist alcohol corrosion.

Environmental concerns about corn ethanol make this fuel less desirable than biodiesel. Advanced cellulosic ethanol, especially when produced from agricultural waste, is significantly more environmentally sustainable than current ethanol stocks. See the Liquid Biofuels section of Chapter 13 for a more detailed discussion of ethanol's environmental impact. Because of doubts about the environmental

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[166] Netaka White and Chris Callahan, *Vermont On-Farm Oilseed Enterprises: Production Capacity and Breakeven Economics* (Vermont Bioenergy Initiative, Vt. Sustainable Jobs Fund, 2013), www.extension.org/sites/default/files/2013 - White and Callahan - Vermont On-Farm Oilseed Enterprises.pdf

[167] The National Biodiesel Board (NBB) provides comments on OEM information on standards and warranties: biodiesel.org/using-biodiesel/oem-information

sustainability and energy balance of ethanol, Vermont will not promote the deployment of E-85 flex fuel vehicles or E-85 refueling stations in the state.

The U.S. DOE has made significant policy and financial investment in the research and development of cellulosic ethanol. These systems, still in the R&D stage, involve large-scale refineries and use the same fuel-delivery model as gasoline. However, that model is subject to inherent market volatility and centralized control. One commercial-scale cellulosic ethanol plant requires more than one million tons of wood per year.[168] Vermont will use any national blend of ethanol in fuels; however, the state should not use its limited biomass resources for the production of ethanol. If sustainably produced cellulosic ethanol eventually replaces corn ethanol on the national market, Vermont may reconsider its position on E-85 flex fuel vehicles and E-85 refueling stations.

Natural Gas

Natural gas used in transportation applications must be compressed under pressure to form either compressed natural gas (CNG) or liquefied natural gas (LNG). Both these fuels require specialized vehicles and specialized refueling stations.

Natural gas offers several advantages over diesel vehicles for medium- and heavy-duty applications. Especially in medium- and heavy-duty applications where electrification is currently not possible, it is preferable to gasoline, diesel, or propane fueled vehicles. Life-cycle GHG emissions for CNG and LNG in medium- and heavy-duty applications are lower than for gasoline and diesel counterparts. Increasingly stringent regulations of tailpipe emissions for new gasoline and diesel vehicles have resulted in newer engines for those vehicles that are nearly on par with natural gas in emissions of hydrocarbons, oxides of nitrogen (NOx), carbon monoxide (CO), and carbon dioxide (CO_2).[169] Taking into account new tailpipe emission regulations, the main advantage of natural gas over gasoline and diesel fuel is cost and price stability, not necessarily environmental benefits.

In Vermont, natural gas is still a fledgling transportation fuel: only .1% of the state's natural gas consumption goes to that use. National trends in vehicle manufacturing and cost, however, will drive the adoption of natural gas as a transportation fuel in the state.

A lack of refueling infrastructure is another limitation on the use of natural gas for longer trips. Fleet vehicles with regular local or circular routes or vehicles used for local public transportation are prime targets for natural gas deployment. Where there are opportunities to foster the use of natural gas to replace diesel or gasoline in medium- or heavy-duty applications, the state should seek to do so.

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[168] Data supplied by the Vermont Agency of Natural Resources

[169] Alternative Fuel Data Center, U.S. DOE, *Natural Gas Vehicle Emissions*, www.afdc.energy.gov/vehicles/natural_gas_emissions.html

Although the use of natural gas in transportation reduces overall emission relative to petroleum-based products, in the long run, moving away from fossil natural gas will continue to be a priority. One part of this strategy is the development of renewable natural gas. The use of renewable natural gas in transportation counts toward meeting Vermont's sectoral goal of deriving 10% of its energy use in transportation from renewable sources by 2025 and 80% by 2050.

Renewable natural gas is the product of anaerobic digestion of organic material. It can be produced by various waste streams, including landfill material, manure, wastewater, and other organic waste including food scraps. It is chemically identical to natural gas and can be added to pipelines and used in end-use equipment without any modification to that equipment, including in vehicles equipped to use compressed or liquefied natural gas.

8.6.9 Strategies and Recommendations

Effective utilization of alternative fuels in transportation will require strong state and regional markets. Although national trends in production, price, and engine manufacturing are driving the adoption of alternative fuels, there are several actions that Vermont can take independently to stimulate the adoption of alternative fuels, to reduce our GHG emissions and improve air quality.

One major barrier to adoption is the lack of refueling infrastructure for biodiesel blends higher than B5, compressed natural gas, and liquefied natural gas; another is the relatively low price of gasoline and diesel. To overcome these barriers, the state should encourage demand by switching to some alternative vehicles in its own fleet, and by encouraging other fleets to do so where it is economical. To build out additional refueling infrastructure when such infrastructure is less economical because of low petroleum prices, the state should consider whether there are ways to encourage new refueling stations, such as public-private partnerships that can share the costs. For example, in dense areas where there may be larger private fleets using compressed natural gas, public transportation fleets could also be converted to natural gas and share the costs of developing new stations.

Recommendations

(1) Support the development of additional refueling stations for alternative fuels for both private and public transportation fleets by sharing station development costs between public and private interests.

(2) Continue working with other regional partners on analyzing a low-carbon fuel standard framework for the region that includes biodiesel blends.

(3) Investigate the feasibility and cost of moving state fleet medium- and heavy-duty vehicles to biodiesel blends, focusing in particular on cost and the availability of refueling stations throughout the state.

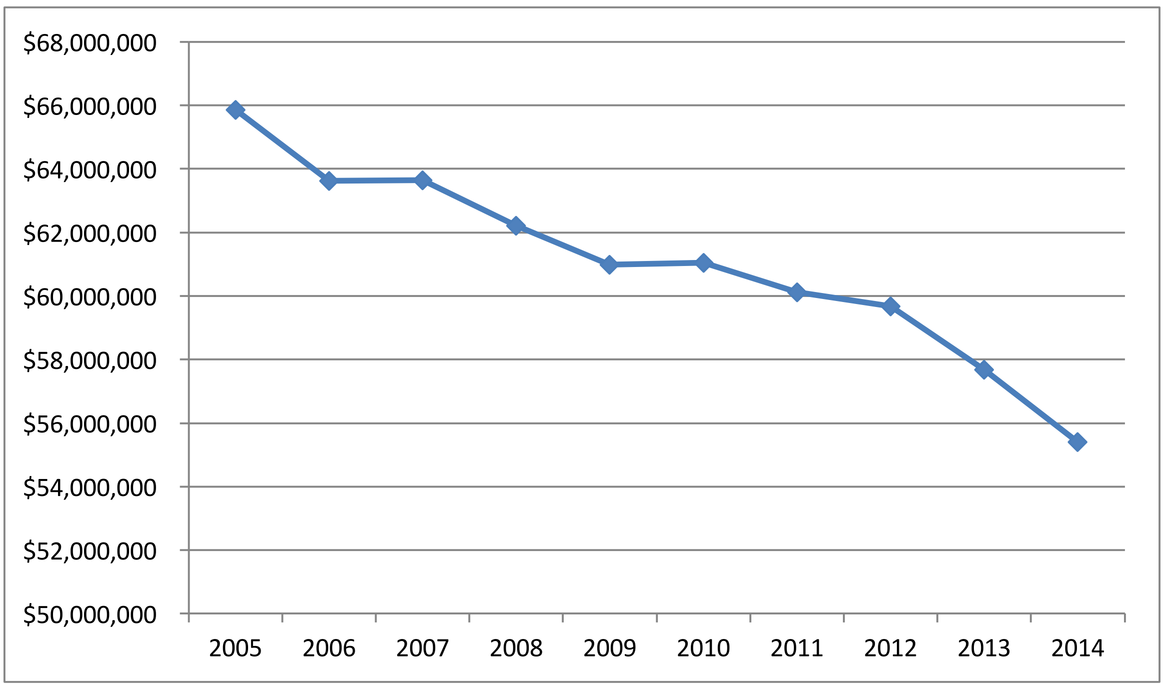
(4) Work with the Clean Cities Coalition to encourage large fleets to switch to natural gas use where biodiesel is impractical.

8.7 Transportation Funding Dilemma

The transportation sector is almost wholly dependent on gasoline or diesel fuels. Most of Vermont's and the country's transportation programs are funded, directly or indirectly, through petroleum fuel taxes, vehicle registration and other motor vehicle fees, and the vehicle purchase and use tax.

Vermont's Joint Fiscal Office issued a report titled *Vermont's Transportation Funding: An Ongoing Dilemma* in October 2009.[170] The long-term problems identified in the report include an anemic revenue base and aging infrastructure. The report a substantial decline since 2008 in both gasoline tax and overall transportation fund revenue, leading to concerns about the future maintenance of the state's transportation facilities. Even before the 2008 decline, transportation fund revenue growth was modest at best.

Exhibit 8-17. Vermont Gasoline Revenue, 2005-2014



Source: Vermont Joint Fiscal Office, Gas & Diesel Revenue and Gallons Report

These funding limitations will grow tighter in the future, as Vermont works to transform the system to reduce petroleum dependency, operate more efficiently, address Vermonters' shifting transportation demands, and meet the state's goals for renewables and GHG reduction. Federal and state transportation funding mechanisms will need to recognize these important priorities.

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[170] Neil Shickner, *Vermont Transportation Funding — An Ongoing Dilemma* (Legislative Joint Fiscal Office, October 2009), www.leg.state.vt.us/jfo/issue_briefs_and_memos/Transportation%20Funding%2010-2009.pdf

Funding levels are needed to maintain roads and bridges in a state of good repair, and more will be needed to improve these facilities for vehicles, bikes, and pedestrians, as well as to grow rail and transit services. Achieving the CEP's objective of reducing transportation energy by 20% and meeting 10% of the need with renewable energy will cause a reduction in taxed fuel sales; as a result, the state transportation fund will be significantly less than it is today, at a level that will not address the state's transportation needs.

Basic maintenance cannot be ignored. Transportation infrastructure is inextricably linked to economic development, and was developed in large part to allow businesses to function and to transport goods and services. Failure to keep up with infrastructure maintenance will result in Vermont businesses losing their ability to compete.

Vermont is faced with another major transportation challenges. The federal highway trust fund is in the red, and Congress has not shown a willingness to find a long-term transportation revenue source.

Highways and bridges eventually need to be replaced. The state's highway system was built in two concentrated periods of investment: in the 1920s and '30s when the national highway system was constructed, and then in the 1950s and '60s when the interstate system was completed. The bridges built in the 1920s and '30s are now approximately 80 years old and are approaching the end of their useful lives. They need to be replaced; at the same time, the bridges built in the 1950s and '60s are now more than 40 years old, and are hitting the midlife point when they require major rehab work if their useful lives are to be extended and maximized.

The Joint Fiscal Office estimates that just to maintain the existing infrastructure in serviceable condition would require spending $415 million a year for the next 30 years. Our current level of spending on infrastructure preservation is $211 million, leaving a spending gap of $203 million. The consequences of this will be deteriorating conditions and higher repair costs, unless we address it proactively now.

Transportation challenges are being faced at the federal level, and some solutions may make sense at a multistate regional level. Vermont must be a leader, and not ignore the funding reality that transportation funding challenges will grow as the state works to reduce petroleum consumption.

CEP implementation must be coupled with changes in transportation revenue policy. VTrans is currently undertaking a study on future non-gas tax transportation revenue sources that will be completed in early 2016.

9 Electric Power

This portion of the CEP addresses Vermont's electricity needs and the resources available to meet them. The discussion in these sections sets the stage for policy recommendations that incorporate both supply-side and demand-side resources for meeting our electricity needs. The CEP recognizes the significant economic and environmental benefits of energy efficiency, conservation, and renewable energy sources, along with the importance of seeking diverse sources of electricity production, ensuring grid reliability, and maintaining the principles of least-cost integrated resource planning.

This chapter contains an overview of electric usage and demand, and explains the shifting context in which electric planning and regulation now operates. It concludes with a discussion of future utility regulatory models and other changes necessary to prepare for a fully modernized and dynamic electric grid. Two approaches work together to provide the state's projected electricity service: managing demand and meeting it with supply. Chapter 10 addresses the state's ability to manage electric energy demand through energy efficiency, load management, and electric energy storage. Chapter 11 discusses tools and technologies available to cost-effectively meet electric demand while advancing state policy objectives, such as the Renewable Energy Standard and robust planning frameworks, including both integrated resource planning and land use planning for siting new generation.

On the grid, energy supplied must be balanced, moment by moment, with energy consumed or lost. The electric grid today is in the midst of a transformation. Historically in its operation, demand at any given moment was taken as given, and generators were controlled in order to meet exactly that demand. Demand was forecast for the day or month ahead, both to plan for generator operations and dispatch and over longer time periods to determine when new generation or transmission might be required. As energy efficiency and demand response have matured as resources, we have seen that efficiency can change long-term forecasts, while demand response can be dispatched — like a generator — to meet peak loads.

Recently, more generation has come online from variable resources, such as wind and solar power, which also have no marginal cost and are therefore "must take" resources in least-cost grid operations, except at times and locations where precluded for grid reliability. These generators are generally smaller in capacity than combustion-based plants, and are distributed in many locations around the distribution grid. Electric-energy storage technologies are maturing quickly, as are technologies for automating and aggregating control of many different kinds of end uses (beyond the water heater controls that have been deployed for decades). Electric vehicles and heat pumps present new challenges and opportunities. Taken as a whole, these challenges present a new grid paradigm in which both demand and supply have both controllable and non-controllable (but forecastable) aspects.

An integrated grid is now possible because of the proliferation of information technology tools throughout the grid — at supply, on the grid itself, and at the end use. This provides the opportunity to optimize the grid in a way not possible before, with significant yet uncertain potential to contain overall and per-unit costs. This paradigm informs Vermont's approach to both managing and meeting electric service demand, as this CEP describes.

Over the last decade, Vermont ratepayers have used electricity from resources that have relatively stable prices and relatively low emissions. Going forward, we will face many challenges if we are to continue to deliver electricity "in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality … and that is environmentally sound."[171] These challenges breed opportunities; indeed, the electric sector has an integral role to play in securing Vermont's energy future, by implementing policies that will lead both to reducing total energy use by one third or more and to meeting 90% of our remaining consumption from renewable sources by mid-century. This CEP incorporates the renewable electric requirements established by Act 56 of 2015, and establishes a goal of 67% renewable electricity by 2025 on the way to 75% or more by 2032.

The challenges and opportunities ahead are a result of Vermont's present circumstances and the events that led us here. In the late 1990s, Vermont resisted the momentum for industry restructuring and retail choice, while the rest of New England and the northeastern U.S. moved toward a more competitive environment that increased exposure to short-term and spot-market prices. Under current market conditions, Vermont appears to have benefited by maintaining a vertically integrated structure: the retail rate for electricity in Vermont is currently the second lowest on average in New England, and is far more stable than in other states. Part of this price advantage is related to long-term contracts entered into by Vermont utilities. Some of these, however, are indexed to the regional market and may, over time, result in prices more similar to those of neighboring states (if less volatile).

Retail electric costs are more than the moment-by-moment or long-term costs of energy; they are also the costs of building and maintaining transmission and distribution infrastructure, generation capacity for peak times, and utility operations. In the case of for-profit utilities, they can also include a limited return to the investor. Utility regulation by the Public Service Board establishes the structure and process for determining total utility revenues and how those revenues are collected from each customer. The design of rates for each customer class is intended to reflect the costs caused by those customers' use of the electric system. This minimizes subsidization of any customer class by other classes, and is considered economically efficient.

Utilities and their regulators are guided by the policies established in Vermont law, which include at their core a goal of least-cost electric service, including economic and environmental costs, consistent with the principles identified in Chapter 3 of this CEP. Per-unit electric rates reflect all these costs and their allocation, divided among all of the customers, kilowatt-hours of energy, and kilowatts of power delivered. Seeking the lowest electric rates and bills, therefore, includes:

- Reducing electric use and acquiring least-cost energy and capacity, to avoid direct costs;

[171] *30 V.S.A. § 202(a)*

- Lowering peak energy use and distributing generation close to load, to reduce Vermont's share of regional transmission costs and avoid the need to build new electric infrastructure; and

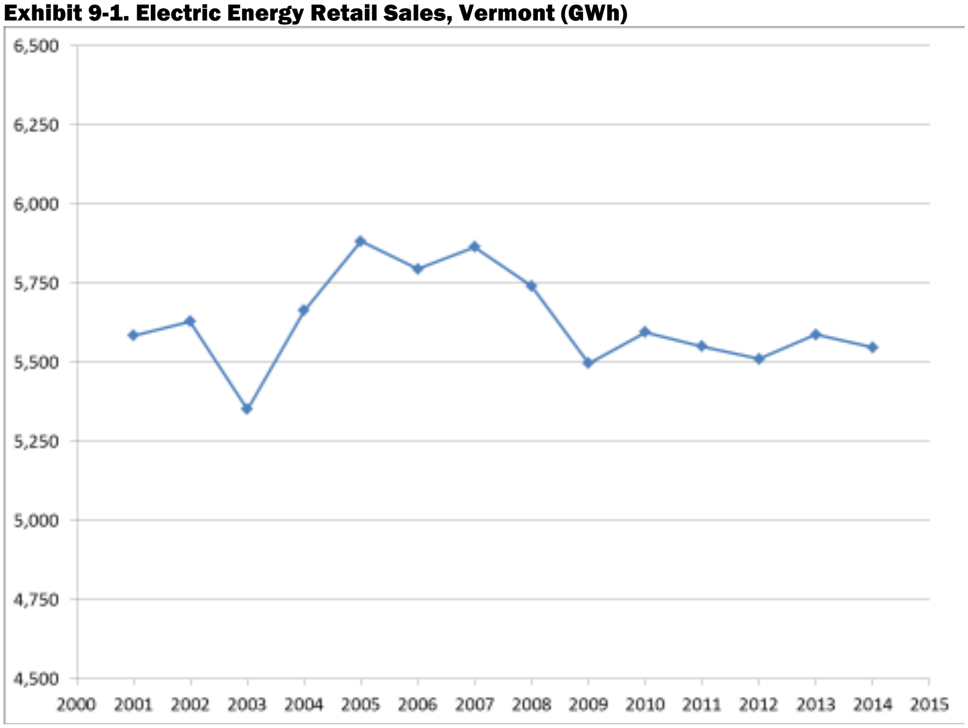
- Using existing electric transmission and distribution infrastructure to the fullest, to share its cost over as many energy units as possible and thereby lower rates.

9.1 Historic and Current Demand and Prices

9.1.1 Vermont Electric Demand

Vermont's annual demand for electricity has generally increased over the last several decades, driven by modest gains in population and overall economic growth. Exhibit 9-1 shows the state's annual electric energy consumption. Since 2005, annual electricity consumption has declined. This pre-recession decline can be attributed in part to the state's electric efficiency investment and programs, which are described later in chapter 10 of the CEP.

Exhibit 9-1. Electric Energy Retail Sales, Vermont (GWh)

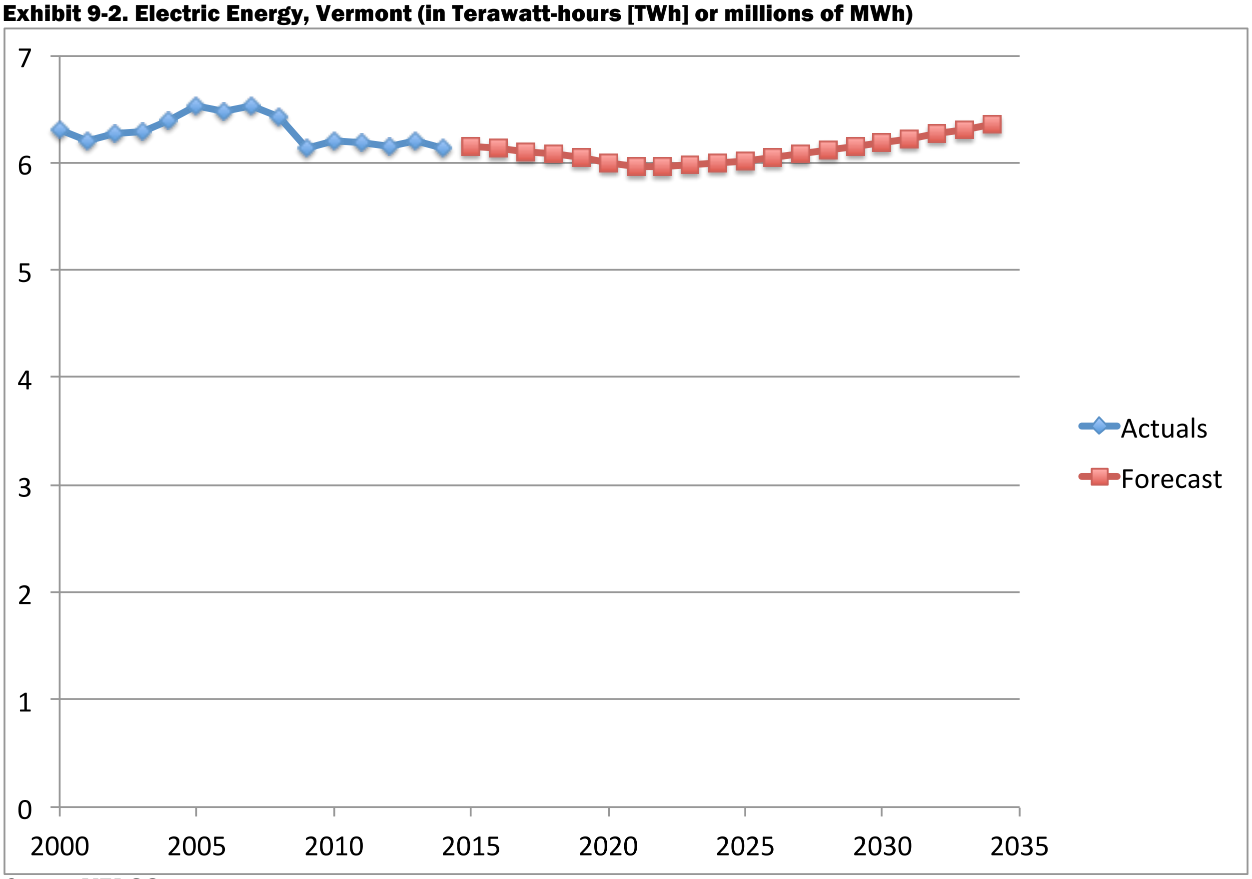


Source: U.S. Energy Information Administration

Vermont Electric Power Company (VELCO) is the state's transmission company. VELCO is required to periodically complete a long-range transmission plan vetted through a stakeholder group called the Vermont System Planning Committee (VSPC). The VSPC is made up of VELCO, electric distribution utilities, the DPS, representatives of demand and supply resources, and representatives of the general public. The long-term VELCO demand forecast is based on forecasts by customer class and energy end uses. That is, the forecast captures changes in customer class and end-use sales trends that are driven by long-term structural changes — such as changes in housing size, improvements in thermal efficiency, and changes in end-use saturation and end-use efficiency trends. The forecast is weather-normalized (adjusted for year-to-year weather variability), and incorporates expected effects from the most recent appliance efficiency standards. In addition, the VELCO forecast reflects a projection of program efficiency savings as completed by EVT.

Overall, the VELCO forecast projects an average annual electric use decline of 0.3% through 2024, followed by an average increase of 0.6% per year through 2034. The VELCO forecast is a thorough, business-as-usual snapshot of projected electric load growth. VELCO's forecast accounts for net metering up to 15% of each utility's peak load, as well as other generation that is "behind-the-meter" as far as the regional grid operation, and an estimated deployment of heat pumps and electric vehicles. As such, it does not include either additional net metering as might be deployed under the new rules under consideration by the PSB, or changes in transmission-level electric demand driven by the additional distributed generation or end-use electrification resulting from Act 56.

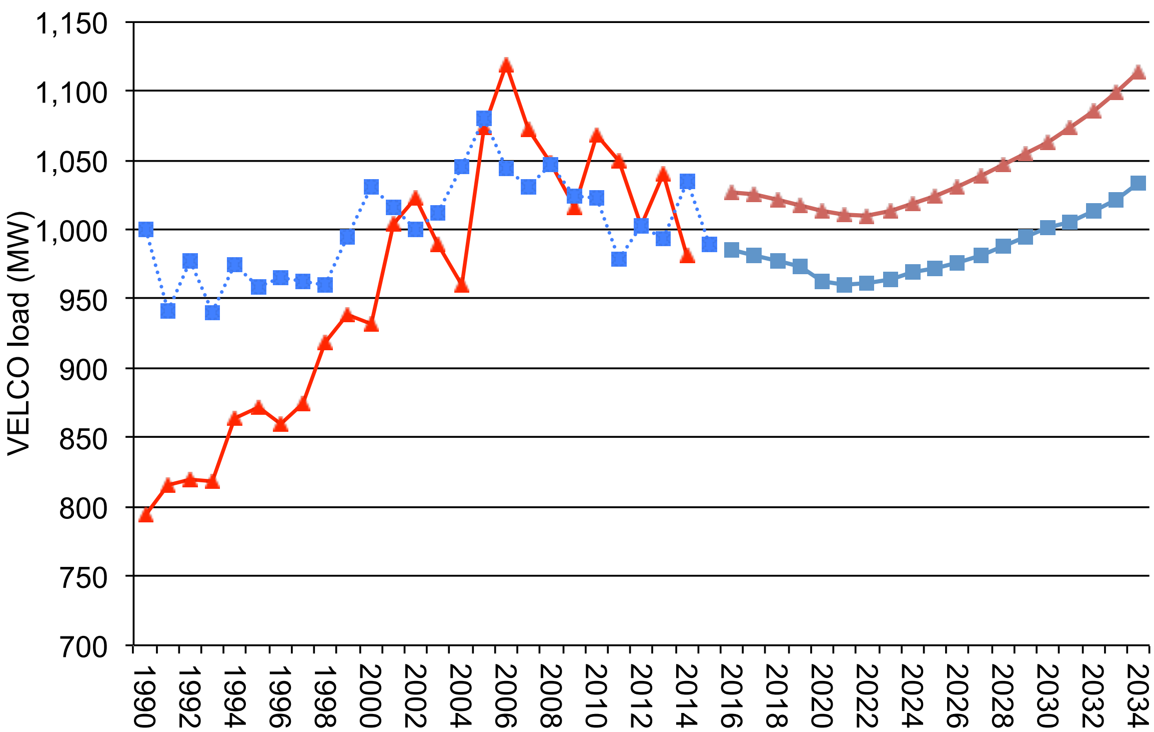
Exhibit 9-2. Electric Energy, Vermont (in Terawatt-hours [TWh] or millions of MWh)



Source: VELCO

Exhibit 9-3 illustrates the winter and summer peak demand since 1990, along with VELCO's recent long-range forecast. VELCO's system was winter peaking until 2002, when the summer peak first exceeded the winter. Winter peaks have been moderated in large part by use of increasingly efficient lighting and a decline in the use of electric resistance heat, while summer peaks rose with increased use of air conditioning. System summer peak demand is forecast to decline to just over 1,000 MW by the early 2020s, then increase to approximately 1,100 MW by 2033. Stronger summer demand growth is largely driven by expected growth in air conditioning load (more households installing more air conditioners). Long-term winter peak demand growth tracks energy projections, with winter peak demand falling through the early 2020s, then rising past 1,000 MW by 2030.

Exhibit 9-3. Vermont Summer Peaks (Red) and Winter Peaks (Blue), 1990-2015, with VELCO Forecast to 2034



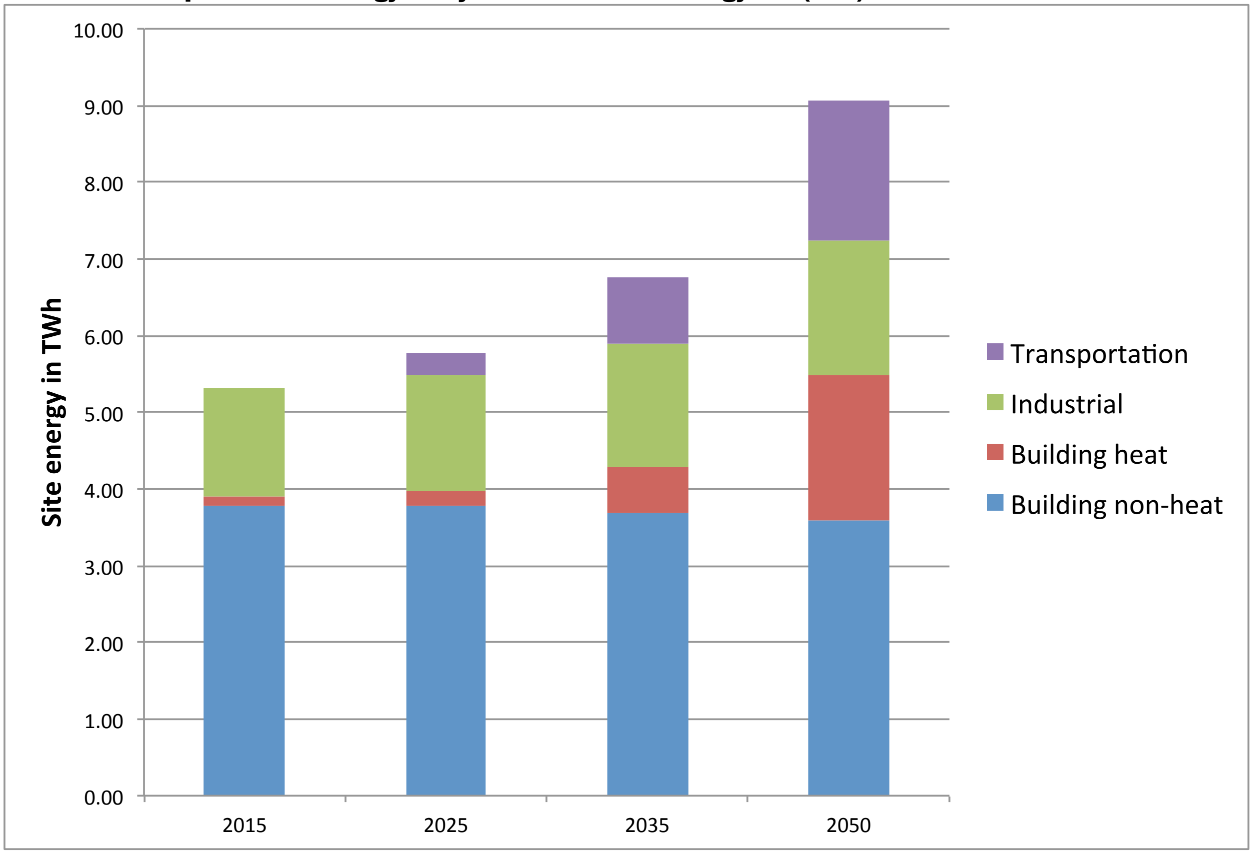
Source: VELCO

9.1.2 Electric Demand for 90% Renewable Energy: Total Energy Study Modeling

The DPS's 2014 Total Energy Study (TES) modeled the economy-wide transition to 90% renewable energy. While the TES modeling encompassed several scenarios for achieving the 90% goal, all showed a significant increase in electric demand from current levels, and higher levels of electric energy use than the TES business-as-usual case and the VELCO forecast shown above. Exhibit 9-4 shows the electric energy use from a composite scenario that uses electricity rather than liquid biofuels for both light-duty vehicles and building heat (modeled as efficient EVs and cold-climate heat pumps; wood energy use remains roughly level with current use).

Given the possibility for increases in efficiency and for the increased use of wood or sustainable biofuels for renewable heat and transportation, this should be considered a higher-end estimate of possible 2050 electric demand. TES model cases that assume widely available and inexpensive biofuels, however, still indicate electric demand at about 80% of the 2050 level in Exhibit 9-4, or more than one-third higher than current use.

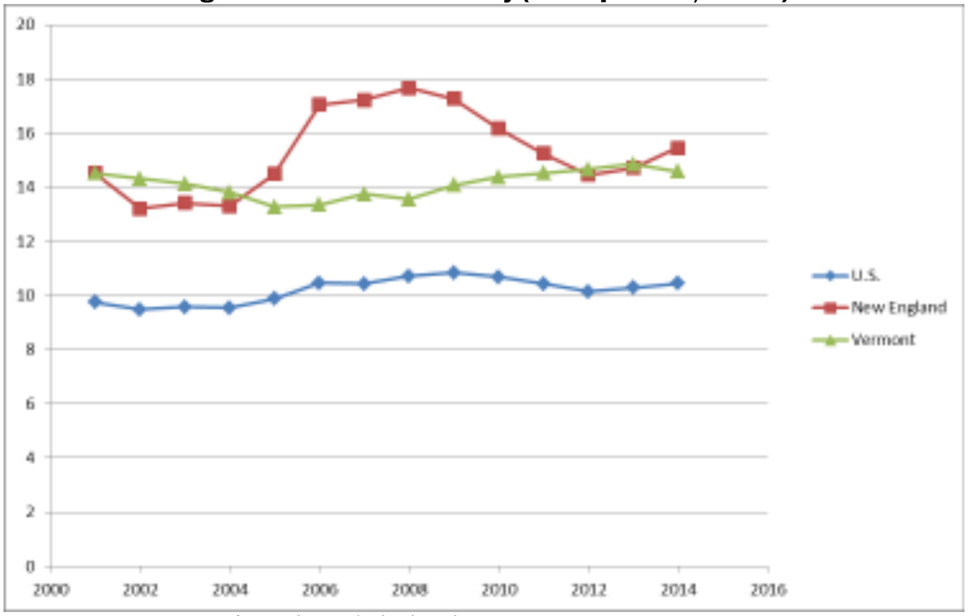
Exhibit 9-4. Composite Total Energy Study Modeled Electric Energy Use (TWh)



9.2 Electric Prices

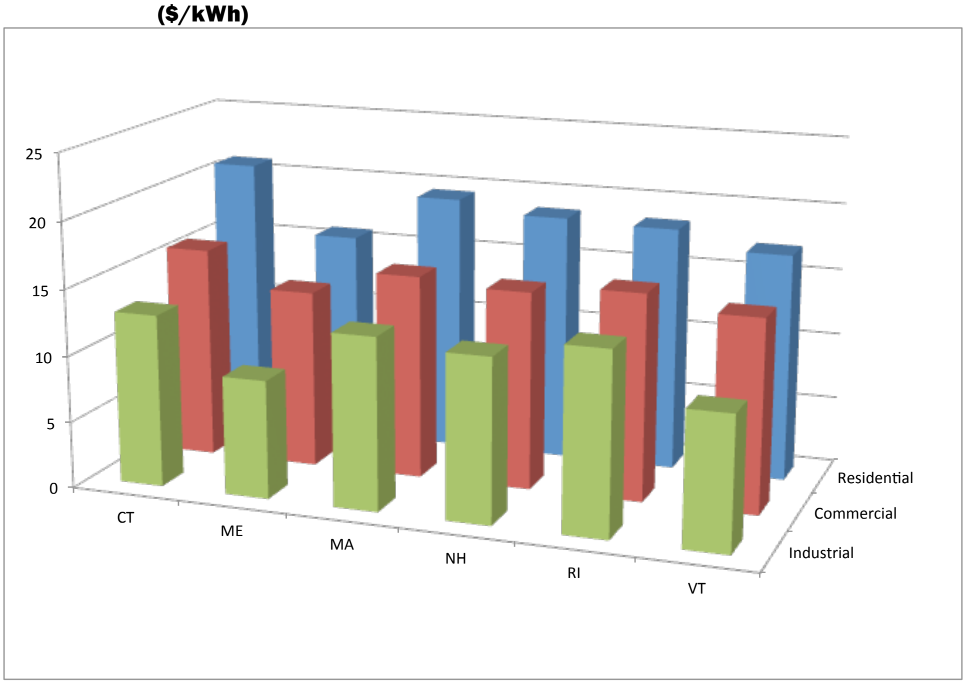
As shown in Exhibit 9-5, Vermont's average price per kWh for retail electricity sales has remained relatively flat on an inflation-adjusted basis for the last several decades. Over the past decade, compared to the region as a whole, Vermont has had favorable electric rates. Exhibit 9-6 shows a snapshot of recent New England and Vermont electric rates. Vermont currently maintains a modest price advantage compared with the region on average, although rates vary by end use sector and by utility.

Exhibit 9-5. Average Retail Price of Electricity (Cents per kWh, 2014 $)



Source: U.S. Energy Information Adminsitration

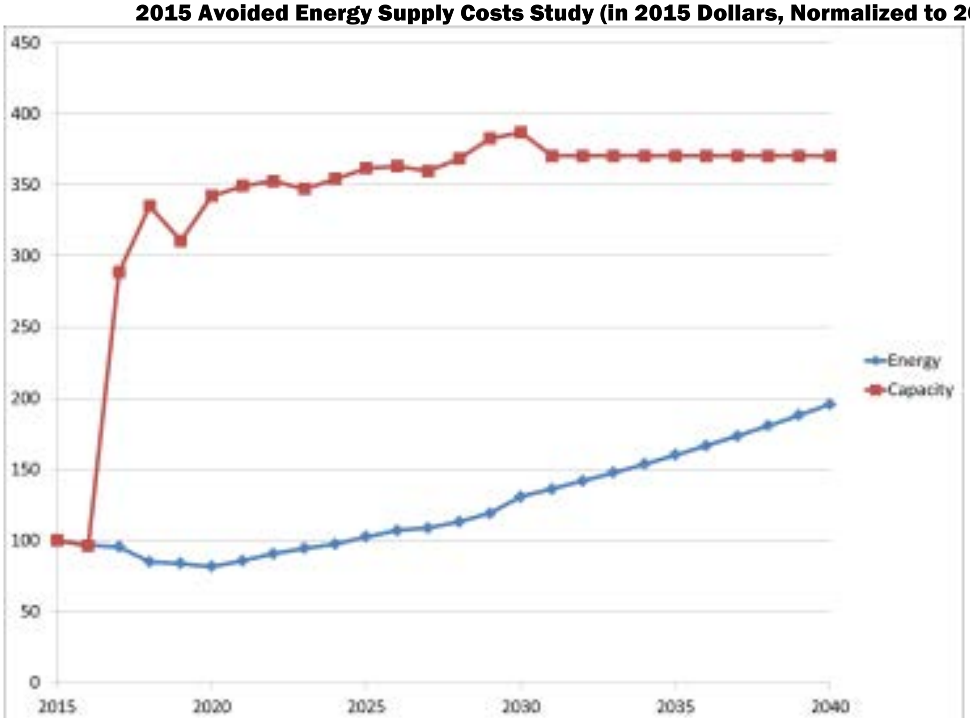
Exhibit 9-6. New England Average Electric Rates by State and End-Use Sector, September 2014 to August 2015 ($/kWh)



Source: U.S. Energy Information Adminsitration

Vermont utilities have significant long-term power contracts with various pricing mechanisms, and these reduce our exposure to the regional markets when compared with other states; but our electric rates will continue to be impacted by the dynamics of those markets. On a periodic basis, the six New England states jointly produce a study of avoided energy supply costs, for use in screening the cost-effectiveness of energy efficiency programs. The most recent forecast, whose results are summarized in Exhibit 9-7, was completed in the spring of 2015 and indicates an expectation of relatively low wholesale energy-market prices for the next decade or so; more recent shifts in the market have further reduced expectations for future energy prices. Capacity market prices are projected to remain high, reflecting a continued need for additional generation capacity at times of peak demand. This need is driven both by rising summer peaks in the region as a whole and by the retirement of older generators throughout the region.

Exhibit 9-7. Wholesale Energy and Forward Capacity Market Price Projections from the 2015 Avoided Energy Supply Costs Study (in 2015 Dollars, Normalized to 2015=100)



Source: Avoided Energy Supply Costs, 2015

Wholesale marginal electricity prices in New England are dependent on the regional price for natural gas. Even though there is little significant gas-fired generation owned or directly contracted by Vermont utilities, our utilities must often rely on the regional market for shorter-term contracts; as a result, Vermont electric ratepayers have some exposure to the variability of natural gas prices. In addition, long-term contracts entered into by Vermont utilities can be based or indexed upon regional market prices.

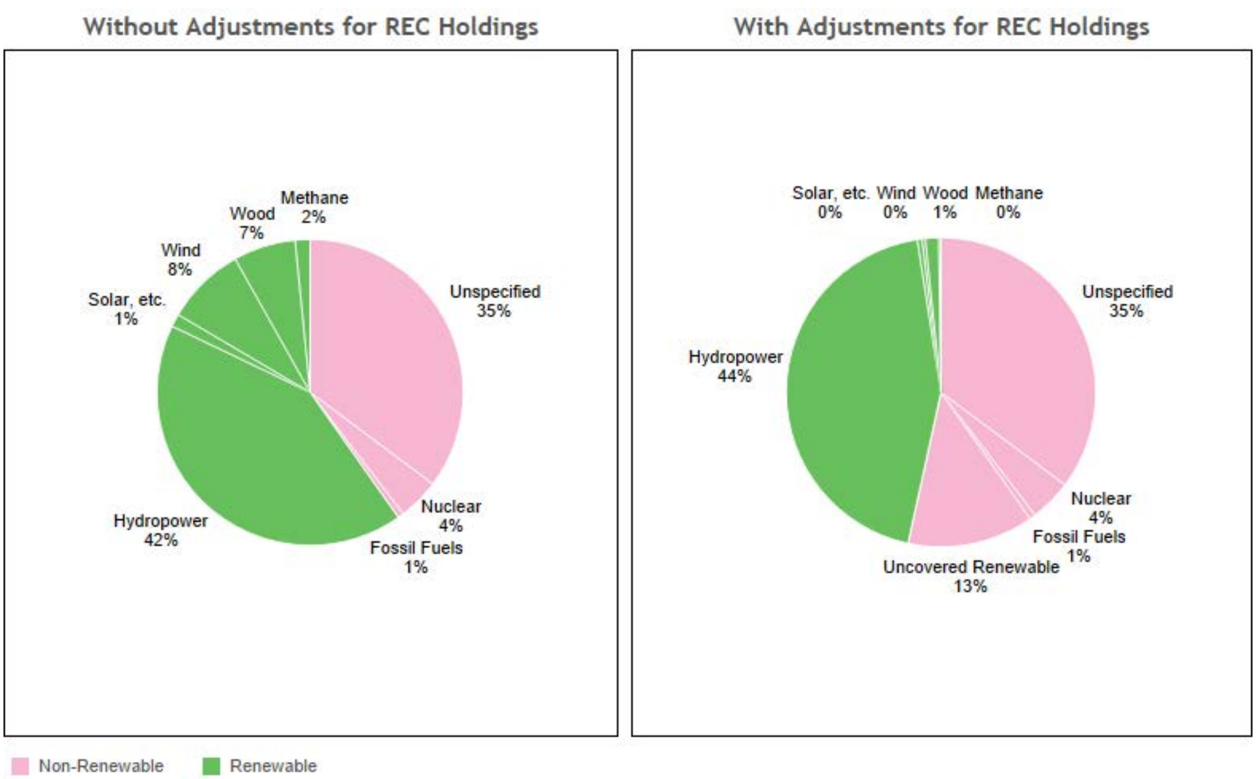
Vermont's less-direct connection to regional natural gas prices can be positive or negative, depending on the price of natural gas. Recent narrowing between Vermont retail electric rates and New England rates is due in part to low natural gas prices driving costs down elsewhere in the region; separation in winter rates is driven by natural gas constraints. Moreover, to achieve the price and environmental objectives that Vermont policy favors, it is incumbent on the serving utility to contract or build resources with certain attributes. For those reasons, the price for electricity in Vermont may not be reflective of the market costs described above.

9.3 Current Electric Supply

Historically, the Vermont electric grid has developed to function as an importer of electric energy, and its ties to New England, New York, and the Canadian provinces have served the state well. Nevertheless, Vermont-based resources have met a significant portion of the state's electric need.

Although the composition of portfolios for any one utility can vary, the aggregate supply of committed contracts or generation units (as opposed to open-market purchases) has provided 85% to 90% of Vermont's energy needs over the last several years, of which approximately 20% has been from Vermont-based resources. Exhibit 9-8 shows the mix of sources that supplied electric energy to end users in 2014. The data are presented both before and after any sales and purchases of renewable energy credits (RECs). The Renewable Energy Standard enacted in Act 56, described in more detail in Chapter 11, will result in significant changes in the net disposition of RECs in utility portfolios.

Exhibit 9-8. Vermont Electric Energy Supply, 2014, before and after REC sales and purchases



This supply mix is currently dominated by stable long-term commitments from a number of sources — primarily Hydro-Quebec (HQ), the Seabrook nuclear facility in New Hampshire, and renewable energy generators owned by or under contract to Vermont utilities, which together will supply between half and two-thirds of the electricity used in the state in the coming years. Utilities are in a period of transition between two HQ contracts: one phases out in stages between 2012 and 2020, while the other phases in over a similar time period. The new contract was signed with HQ by a coalition of Vermont utilities for 218 to 225 MW of power for 16 hours per day, making it roughly one-third smaller than the previous contract.

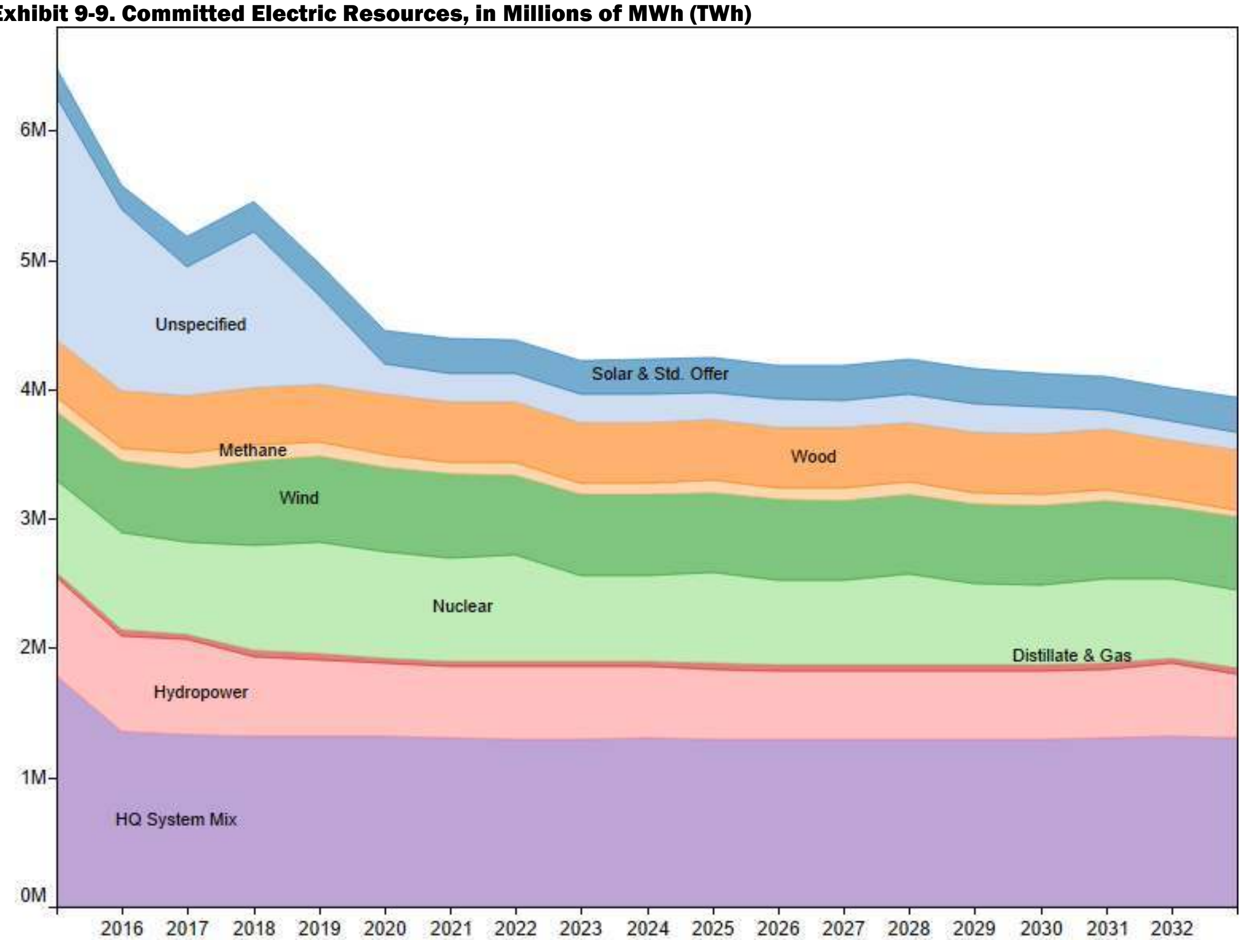
A significant portion of electricity supplied to Vermont end users currently comes from renewable resources. In 2014, in-state hydroelectric power accounted for 11% of supply, while other in-state renewable generation accounted for approximately 2%.[172] Power generated from renewable resources under contract to or owned by Vermont utilities, with renewable energy certificates sold to other utilities, accounts for another 16% of Vermont's electric supply, for a total of nearly 30%.[173] When the renewable power from Hydro-Quebec, which has been approximately 30% of supply, is counted, nearly 60% of the power supplied for purposes of Vermont end-use consumption currently comes from renewable sources, before REC sales. While not downplaying the challenges and efforts necessary, we believe this shows that a goal of acquiring an increasing fraction of our electric supply from renewable sources is reasonable and attainable.

As shown in Exhibit 9-9, there is a gap between contracted supply and expected demand. There is, however, an excess of supply in our regional market at this time. Vermont remains tied to the regional power pool, so Vermonters will have access to the vast resources inside New England and neighboring areas through the wholesale markets.

[172] The percentage of energy from in-state renewable sources varies from year to year, mainly owing to fluctuations in river levels and the associated water availability for hydro generation. Wood biomass electric generation also varies from year to year based on market prices for electricity.

[173] Vermont utilities own commercial-scale wind and landfill methane projects. Most of the attributes from the landfill methane projects are sold into neighboring Vermont markets, and therefore cannot be claimed in Vermont as renewable energy.

Exhibit 9-9. Committed Electric Resources, in Millions of MWh (TWh)



9.4 Electric Generation in Vermont Today

Vermont utilities should continue to diversify their portfolios with appropriate mixes of renewable energy, through contract procurement and ownership of generating supply via both in-state and out-of-state sources, as part of the effort to increase the total renewable generation sources in the state's power mix to at least 75% by 2032, with new distributed generation connected to Vermont's distribution grid growing to 10% of retail electric sales over the same time frame. This section summarizes the current resources in the electric portfolio, while Chapter 11 addresses changes in that portfolio between now and 2050.

Generators can be divided into classes, based on their size and how they connect to the grid. This discussion uses four classifications: utility-owned generation; independent power producers (IPPs) that operate under power purchase agreements (PPAs) with Vermont utilities; independent power producers (IPPs) that operate under the Standard Offer or Rule 4.100/ Public Utility Regulatory Policies Act (PURPA) programs; and customer-owned net metered generators. *Distributed generation* is defined to include generators under 5 MW in capacity that are tied to utilities' distribution circuits; this could be any classification. Distributed generation reduces the load on transmission systems by meeting load on a distribution circuit with generation on that or a nearby circuit. With the closure of the 620 MW Vermont Yankee Nuclear Power Station in Vernon, Vermont no longer has any large-scale centralized electricity generation.

9.4.1 Utility-Owned Generators

Utility-owned generators include the McNeil Generating Station (50 MW, wood biomass), Kingdom Community Wind (63 MW), VPPSA's combustion turbines in Swanton (40 MW), Burlington Electric's gas turbine (25 MW), Washington Electric Coop's Coventry Landfill methane plant (8 MW), Searsburg wind facility (6 MW), and a number of small hydroelectric facilities (totaling 110 MW) and solar PV generators (totaling 4 MW[174]).

9.4.2 Power Purchase Agreements

In addition to utility-owned generators, Vermont has several generators owned by private merchant producers under contract to deliver power to our utilities. Recently permitted or constructed examples include the Sheffield wind project (40 MW) and the Georgia Mountain wind project (10 MW), as well as more than 7.5 MW of solar PV (6.6 MW of which is located in the Rutland area).

9.4.3 PURPA and the Standard Offer

The PSB's Rule 4.100 and the Standard Offer program both establish statewide structures under which generators' output is distributed among Vermont's utilities according to their load.

Many of the currently operating, independently owned renewable resources in Vermont were developed in response to the Public Utility Regulatory Policies Act (PURPA). PURPA was passed by the U.S. Congress in 1978 to create a framework that allowed renewable projects and cogeneration projects access to the grid at avoided cost rates. Each state was left to implement PURPA on its own; Vermont's implementation of PURPA was through Rule 4.100.

Rule 4.100 allowed renewable generators to access stably priced long-term contracts. Twenty hydro projects and one large wood project entered into contracts under this rule. The rule also set up a central purchasing authority — a role filled by Vermont Electric Power Producers, Inc. (VEPP) — to purchase the output from qualifying facilities and allocate the costs and energy among the Vermont utilities. The rates for these contracts were established largely during the 1980s and early 1990s, on the basis of then-forecasted future energy prices. Those estimates have proven to be relatively high compared to actual market prices since the late 1990s.

Although Rule 4.100 and PURPA were successful in bringing renewable energy and independent power to Vermont and much of the region, this approach to stimulating the market proved to be an expensive

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[174] 4 MW of awarded CPGs. CPG applications have been received for an additional 13 MW of utility-owned solar PV.

one when evaluated in retrospect. The 15 remaining Rule 4.100 renewable energy projects and their capacity can be found in Exhibit 9-10. As can be seen, many of these projects have contracts ending soon. Several have already expired; these generators are independently participating in the Independent System Operator of New England (ISO-NE) wholesale markets, or have transitioned to the net metering program. One former Rule 4.100 project, the Ryegate wood biomass plant (20 MW), operates under an agreement subject to the structure of 30 V.S.A. § 8009. Recently several possible new projects, both wind and solar PV, have expressed interest in contracts.

Exhibit 9-10. Rule 4.100/PURPA Generators

Project[175]	Capacity[176] (kW)	Contract Ending Date
Barnet	490	Oct. 31, 2016
Comtu	460	Dec. 31, 2018
Dewey's	2,790	Jan. 31, 2016
Dodge	5,000	Dec. 14, 2020
Emerson	230	Oct. 31, 2015
Killington	100	May 31, 2016
Moretown 8	920	Jan. 31, 2019
Nantana Mill	220	Mar. 31, 2020
Newbury	270	Oct. 31, 2017
Ottauquechee	2,180	Aug. 31, 2017
Sheldon Springs	26,380	Mar. 31, 2018
Slack Dam	410	Oct. 31, 2017
Winooski 8	910	Dec. 31, 2015
Woodside	120	Apr. 30, 2017
Worcester Hydro	170	Oct. 31, 2016

The Standard Offer program began in 2009 with the offering of fixed prices for up to 50 MW of capacity from small (2.2 MW or smaller) renewable generators. VEPP purchases the output from these projects and distributes it to the utilities, similar to the Rule 4.100 structure. The program has since expanded to both encompass many "cow power" anaerobic digesters, and to allow for an increasing annual allocation of new capacity, awarded via competitive solicitation.

To date, contracts have been awarded to 68 generators with a total capacity of 71.8 MW. This includes 38 solar PV systems totaling 59 MW, six small wind projects totaling 520 kW, six hydroelectric projects totaling 4.9 MW, two woody biomass CHP projects totaling 1.2 MW, one landfill methane project of 560 kW, and 15 farm methane projects totaling 5.4 MW. Fifty-one projects totaling 52.6 MW are operating.

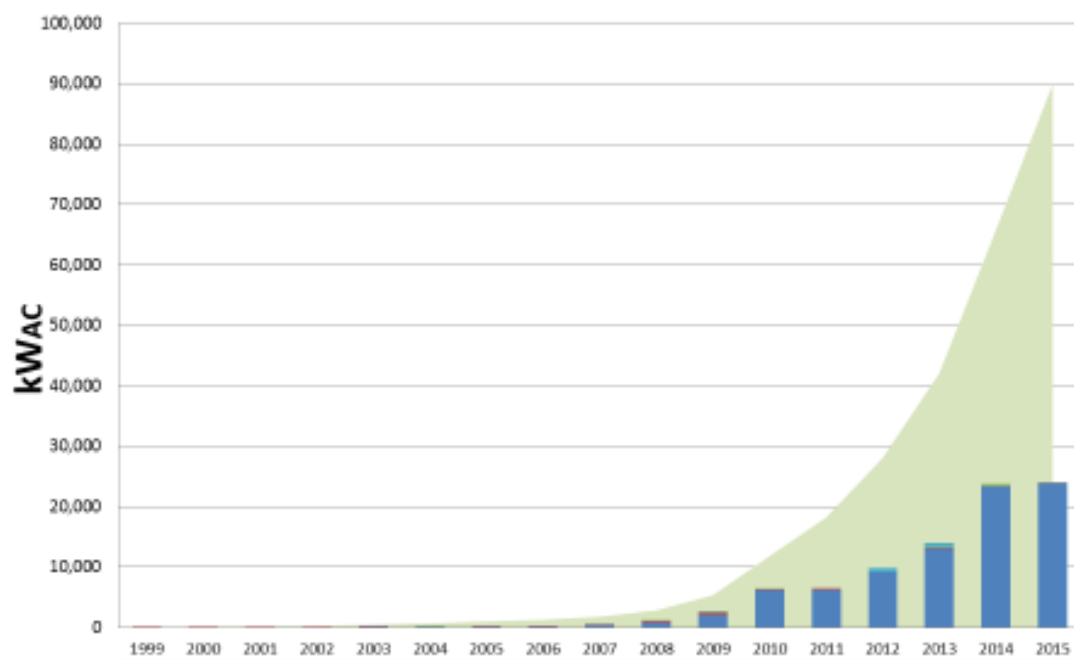
[175] All the operating Rule 4.100 projects are hydroelectric plants.

[176] Capacity listed is maximum capacity. In some months the capacities for some of the plants decrease because of water flows.

9.4.4 Net Metering

As of November 2015, nearly 90 MW of net metered generating systems have received certificates of public good. Exhibit 9-11 shows the sharply increasing trajectory of permitting and cumulative capacity of such projects in the last several years. Net metered projects are limited to 500 kW or less, outside of several exemptions for larger projects (up to 5 MW) allowed under Act 99 of 2014.

Exhibit 9-11. Net Metered Permitted Capacity by Year and Type



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Capacity	50	99	176	228	441	675	986	1,261	1,758	2,808	5,324	11,781	18,186	28,049	42,066	65,787	89,871
Hydro	-	-	-	-	-	-	-	-	-	-	18	-	-	716	684	-	380
Methane	-	-	-	-	-	65	-	-	-	19	39	127	-	-	348	293	-
Wind	32	10	28	31	98	72	124	102	149	158	482	154	239	66	125	98	99
Solar	18	39	49	22	114	97	187	174	347	874	1,976	6,176	6,166	9,081	12,980	23,331	23,634

Source: DPS, data through November of 2015

9.5 Power Sector Transformation

Power sector transformation refers to a strategy by which states, utilities, and other partners seek to capture the value of distributed energy resources (DER) for the benefit of consumers through lower costs, cleaner generation, and better system reliability. This transformation, sometimes also called reform, not only affects the electric distribution utilities (DUs) but leverages them to facilitate change in ways that encourage greater customer participation and entry of new market players into the business of supplying electricity services. Regulatory interventions and oversight become the main instrument for achieving these changes. Power sector transformation charts a course that fundamentally alters the way utilities seek to reduce costs and improve system performance[177]. The goal is to capture system, societal (if that is

[177] That is to say, through industry consolidation and economies of scale.

the preference in a jurisdiction), and customer value from small distributed local resources, and from complementary changes to regulation and the role of the DU.

At a high level, global trends in the enabling communication technology and distributed energy resources create opportunities for improvements in the costs, reliability, and environmental performance of the electric utility sector. To facilitate the change, complementary policy, regulation, and utility efforts will be needed sooner rather than later. Distributed energy resources and communications capabilities are still evolving, but the path is relatively clear. Distributed energy resources such as solar and wind, combined with distributed storage, flexible loads (such as electric vehicles and controllable devices), and a centrally managed platform, offer great potential for improving the grid's performance. The central question is: How do regulators, system operators, and electric distribution utilities need to evolve the system to remove barriers, enable the distributed grid to emerge, and motivate the DUs to function as a cooperating partner in facilitating these changes?

Several U.S. states have taken the lead in this transformation, and have begun to take steps toward it by launching regulatory processes. Though it has not taken explicit and separate steps, Vermont is in many ways well along its own path. The RES in Act 56 sets an explicit structure for distributed generation resources to support the grid, and explicitly invites electric utilities to partner outside their traditional regulated role, to reduce customers' use of fossil fuels while managing DERs to enhance overall cost-effectiveness.

Vermont's earlier actions to establish energy efficiency utilities is another example of its steps along the path. The state is now at a stage at which it can continue to chart that path while staying aware of progress made in neighboring states and other regions of the U.S. Summarized in Appendix A are some of the relevant features of select state efforts, beginning with New York's Reforming the Energy Vision (REV) process and then outlining the work of other active states that will be informative to Vermont.

Other states either have opened formal regulatory proceedings or have informal efforts underway, with some measure of support or acknowledgement from the executive branch of government. States like Hawaii are experiencing the pressure for policy and regulatory reforms in real time, as the combination of high costs and a wealth of solar potential results in high penetration of distributed resources.[178] Others that have either formal processes or some other type of effort underway or in development, relating to sector transformation, include New York (the REV process mentioned above), California, Minnesota, Michigan, Massachusetts, the District of Columbia, and Rhode Island. The mix of states that are active includes both retail-choice states and those like California that are under more traditional integrated utility systems. Illinois, Connecticut, Maryland, and New Jersey are in the process of planning next steps.

The list of topics included in these efforts are many, but they center on identifying both the value and challenges of DER interventions in the distribution system, and on how to identify and use a transparent

[178] In April 2014, the Hawaii PUC reported that approximately 10% of residential customers have rooftop PV. White Paper, April 2014, puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

system of valuing all system resources, whether utility or customer investments. Key topics being addressed by efforts to engage in power sector transformation include those that relate to redefining the role of the regulated company, the utility business model (or alternative regulation), distributed resource planning, distributed resource access, integrating wholesale with retail markets, and rate design. Because of resource constraints, serial efforts to address these focus areas are common. Demonstration projects appear to be an important component of the transformation process.

9.5.1 Context for Vermont's Transformation

In many ways, Vermont's current regulatory and policy framework is designed to promote the development of distributed energy resources, and the planning process is likewise designed to capture value from DER. Vermont utilities are on a three-year planning cycle to develop least-cost integrated resource plans that are intended to identify least-cost resources, whether central-station or distributed energy resources. Vermont's planning framework for bulk transmission and subtransmission involves a collaboration of VELCO, the utilities, the DPS, and representatives of the public through the Vermont System Planning Committee, and includes consideration of DER as part of non-transmission alternatives (NTAs).[179] This process also involves a fairly unique effort to integrate baseline forecasts of energy demand with efficiency planning efforts, in developing integrated statewide and localized forecasts of energy demand.

The process of grid modernization is well underway, with advanced metering infrastructure in place in most households and businesses. More than 90% of the state is served by utilities that were relatively early adopters of AMI (including BED, GMP, WEC, Stowe, and VEC). This creates a number of opportunities for innovative rate design and controlled charging of flexible loads, including electric vehicles.[180] Retail rate design offers considerable potential to encourage customers or entities controlling loads to capture locational value for the benefit of customers. Rate design is discussed further in chapter 10.

The planning structures in Vermont could be leveraged or extended to better address distribution system planning efforts around DER, either on a utility-by-utility basis, or by focusing it first on the larger systems. Other jurisdictions are looking at ways to redesign their systems to allow for bidirectional flows. This need is now well-recognized for distribution systems in most jurisdictions, including Vermont. Given the long-lived nature of any investments, this is an issue on which Vermont's electric distribution system planners should get ahead.

While Vermont does not have competitive retail markets, this does not appear to limit its ability to rely on market forces to deliver on DER potential. At least one utility, GMP, has helped to guide innovation in

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[179] Vermont System Planning Committee, www.vermontspc.com/

[180] Controlled power to household loads dates back decades in Vermont (used by utilities for rental electric hot water heaters in the 1980s), but the opportunities to apply increasingly to electric vehicle loads, and most thermal household and commercial loads.

the state, in cooperation with partners like the Hinesburg, Vt. firm Renewable NRG Systems.[181] States can clearly make significant progress toward capturing value from DER in the absence of retail choice. Indeed, utilities in California have made spurring the development of markets for DER services a foundational principle.[182]

Many elements of the value proposition of transformation are connected to centralized planning efforts that can be adopted regardless of the use of retail choice. This reflects the reality that portions of the system, including many grid services, remain fundamentally part of the distribution system platform monopoly. Market-based reforms, including retail choice, offer additional promise for capturing dynamic efficiency that results from a competitive process with many players. Vermont is unlikely to embrace retail reforms in the near future, but could take measured steps to encourage some dynamic efficiencies to the participation of third-party DER providers and aggregators, consistent with the principles discussed in chapter 11.

9.5.2 Opportunities Looking Forward

A comprehensive approach to efforts around power sector transformation would include efforts to revisit grid system planning and grid modernization, especially distribution planning; the business model (or alternative regulation that applies to Vermont distribution companies); options for rate design, including those enabled by advanced metering infrastructure (see section 10.3.1); and issues around access to the grid, including the state's existing interconnection regime. A serial approach would prioritize these several opportunities for improvement with an overall direction in mind.

Vermont has already reformed grid planning in ways that allow for some consideration of DER at the level of transmission and subtransmission[183]. The state has also made substantial progress with the utility business models for its largest electric utility, in ways that largely decouple sales from profits[184]. Vermont has created a successful framework for implementing electricity energy efficiency that integrates with

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181 GMP has partnered with NRG and provides innovative storage services using Tesla batteries. GMP has also worked to develop innovative pilots through its Energy Homes of the Future and Energy City of the Future in Rutland. Some of the innovative solutions offered by GMP and NRG are presented on GMP's website at www.greenmountainpower.com/innovative/gmp-nrg-making-vermont-a-national-leader/

182 See, for example, the DRP of Southern California Edison. Principle #5 states that "competitive processes should be utilized to the greatest extent possible," asserting that this is "in turn a foundation of Commission policy for creating customer value." Southern California Edison, Application of Southern California Edison Company (U 338-E) for Approval of its Distribution Resource Plan, July 1, 2015 at 9, available at www.cpuc.ca.gov/NR/rdonlyres/0165F5EC-8FD4-44C6-9818-A04452961CEC/0/A1507XXX_DRP_Application_SCE_Application_and_Distribution_Resources_Plan_and_Appendices_AJ1.pdf

183 Vermont Public Service Board Docket 7081, Order Approving Memorandum of Understanding, psb.vermont.gov/sites/psb/files/orders/2007/7081finalorder.pdf

184 Public Service Board, *Alternative Regulation*, psb.vermont.gov/utilityindustries/electric/backgroundinfo/altreg

grid planning. Metering infrastructure has been installed to enable advanced forms of retail pricing[185], recommendations for which are described in Chapter 10; and Vermont has pursued a steady path toward the development of renewables through net metering and standard contracts and in supporting the adoption of electric vehicles[186].

Going forward, Vermont has options. We can mirror the efforts of states like New York and California, which have undertaken a fairly comprehensive review of the entire system. But many of the issues involved with the reforms are technical in nature, and Vermont would be challenged to assemble the critical mass of engagement from business and advocates that larger states such as New York and California can bring to bear. We can, however, benefit from lessons learned in other states.

At the other extreme, Vermont can maintain an observer role in monitoring the efforts of states that are most active in formal power sector transformation processes, such as New York, California, and Massachusetts. As an observer, Vermont can still capture the lessons learned from these early leaders and build on proposed reforms, or on the successes of implementation efforts. The Distribution Resource Planning (DRP) proposals and progress of New York and California on a wide range of issues offer great potential for accelerating progress around capturing greater value from DERs.

Another choice that seems advisable allows the state to address the impending challenges and opportunities in a way that preserves focus and control through measured steps forward. Under a path such as this, Vermont would identify priorities and build on earlier successes and its own circumstances. Each relevant utility regulatory proceeding before the PSB presents an opportunity to advance the modernization and transformation of Vermont's electric sector. A wide range of PSB proceedings — including but not limited to alternative regulation, rate design, and RES-related dockets — would be appropriate contexts to identify utility deliverables and design regulatory and programmatic structures to achieve them. These proceedings provide an opportunity to demonstrate potential new approaches, and to incorporate best practices learned from in-state or other-state pilots, demonstrations, and regulatory structures. Such processes would allow space for transparency and public participation.

By crafting demonstration projects that meet certain well-defined objectives, Vermont utilities can play an active role in helping to shape the future for DER. This is analogous to the seven demonstration projects that are already approved and being pursued for New York, and those that have been proposed by California utilities in their distribution resource plans filed on July 1, 2015. Some of these pilots were created by local governments, universities, and local groups cooperating with the utilities. The scope of these demonstration plans could be the subject addressed in PSB proceedings. Here, companies such as

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185 Vermont DPS, *Advanced Meter Infrastructure (AMI) Plans*, publicservice.vermont.gov/topics/electric/smart_grid/amiplans

186 VEIC, *Substantial Growth in Number of Electric Vehicles in Vermont over the Past Year,* (2014), www.veic.org/media-room/news/2014/11/03/substantial-growth-in-number-of-electric-vehicles-in-vermont-over-the-past-year

GMP could work with their partners to develop and demonstrate a DER platform, or to pilot project initiatives, consistent with goals for efficiency, clean energy, and improvements in reliability.

Recommendation

(1) *Utilities, the DPS, and the PSB should each use their roles in regulatory proceedings to advance the further alignment of utility actions with power sector transformation that advances the general good of the state. The DPS and PSB should be especially cognizant of the need for public engagement and transparency in these aspects of each proceeding.*

10 Managing Electric Demand

The state's first and best least-cost option to meet expected electric energy demand is demand-side management (DSM). This chapter provides an overview of the current state of electric efficiency programs and policies in Vermont, discusses the impact of DSM on state and regional transmission and capacity needs, and examines the many ways in which electric efficiency provides benefits for Vermont. Looking forward, the chapter concludes with discussions of the challenges of further increases in efficiency, and the potential for Smart Grid technologies to create new DSM opportunities as well as load management strategies and integration of storage.

DSM programs and policy considerations in Vermont have traditionally focused on utility resource decisions and investments. But there are energy efficiency options for all categories of fuel, including electricity, motor gasoline, and fuel oil for heating and process needs. This chapter considers efficiency as an electric resource acquisition strategy; however, it is imperative to recognize that energy efficiency investments for all fuels should be considered holistically. Energy consumers base decisions on total-building energy bill and consumption patterns, of which electricity usage is just one important part. Chapter 7 discusses thermal efficiency options, considering strategies for encouraging energy reductions on a whole-building basis as well as industrial process heat. As a result, this chapter is limited to discussing the resource-acquisition implications of electric energy efficiency, other DSM options, load management, and storage.

Significant efforts to reduce electric demand should not be translated into a policy in which all increases in electric energy and demand/consumption are avoided. Electric energy must be used efficiently and strategically. As other chapters of the CEP point out, *increases* in electric energy consumption in certain sectors and for certain end uses are probably in the best interests of the state. For instance, Chapter 8 calls for policies that will facilitate increases in plug-in electric vehicles, and Chapter 7 discusses a hypothetical fuel mix for meeting the 90% renewable goal by 2050 whereby some existing fossil fuel heating is switched to electric heating, which would require an increased penetration of cold-climate heat pump technology.

Electric energy DSM is not at odds with such policies and concepts; it is another tool to facilitate their implementation. The goal is to use the cleanest, most efficient, most cost-effective energy for any particular end use. As this chapter describes in detail, electric efficiency programs have potential to save Vermonters money on their electric bills while providing the state with significant economic and societal benefits.

Electric demand management encompasses a range of service alternatives that include energy efficiency and load management strategies. Efficiency investments consist of selecting or installing devices and/or equipment that will improve operations and perform work using less energy input than would otherwise be necessary. *Load management* is generally associated with strategies and technologies focused on reducing demand during peak demand times, to shift usage from peak to off-peak periods. For example, *demand response* and *smart rates* are load management strategies whereby electric customers are compensated for not using electricity during specific peak demand periods when capacity is constrained. Electric energy efficiency and load management strategies are the subjects of the bulk of this chapter.

Many of this chapter's strategies and recommendations seek to reduce electricity consumption during peak periods, the hours of day and times of the year when demand is at its highest. The transmission and distribution systems must be sufficiently robust to accommodate this demand, and there must be sufficient generating capacity to meet peak demand even if those "peaking" generating units are only turned on for a few hours each year. Were it not for those few hours, we would need fewer generating stations and fewer investments in transmission and distribution infrastructure. As a result, these few peak hours drive many costs associated with the electric system — including charges for transmission and future capacity build-outs at the regional level (RNS and capacity charges) and local investments in distribution and sub-transmission infrastructure.

The highest peak demand usually occurs in the summertime, on the hottest days during the afternoon hours.[187] Electricity used during peak times provides critical services — including air conditioning, which is an effective mitigation option for reducing heat-related health impacts, especially for vulnerable individuals such as older adults or the chronically ill. As the climate warms, providing reliable ways to cool buildings will become more important for protecting vulnerable people. Vermont strives to provide critical building-cooling services while keeping peak demand as low as possible. Equipment and appliances that respond to smart rates or utility signals offer such an opportunity and are discussed in greater detail under Load Management in the Demand Response sub-section.

10.1 Managing Vermont's Electricity Demand (Goals and Objectives)

Vermont law sets forth certain standards and criteria that the PSB must consider when determining budgets for energy efficiency programs. Under 30 V.S.A. §209(d)(3)(B), when establishing the amount of the energy efficiency charge and its allocation, the PSB has to determine the appropriate balance among eight stated objectives, with particular emphasis given to the first four objectives:

1) Reducing the size of future power purchases,
2) Reducing the generation of GHGs,
3) Limiting the need to upgrade the state's transmission and distribution infrastructure,
4) Minimizing the costs of electricity,
5) Reducing Vermont's total energy demand, consumption, and expenditures,
6) Providing efficiency and conservation as part of a comprehensive resource supply strategy,

[187] Because of distributed solar generation, which has the effect of meeting demand as it occurs in the distribution system, peak consumption as it affects resource acquisition and transmission investments may be shifting later in the day.

7) Providing the opportunity for all Vermonters to participate in efficiency and conservation programs, and
8) Targeting efficiency and conservation efforts to locations, markets, or customers where they may provide the greatest value.

In addition, the following additional statutory goals and objectives related to electric energy efficiency are included in Title 30 of the Vermont statutes:

1) §209(d)(3)(b): "The [energy efficiency] charge shall be reviewed by the Board for unrealized energy efficiency potential and shall be adjusted as necessary in order to realize all reasonably available, cost-effective energy efficiency savings. "
2) §209(f)(14) requires that the Board consider the impact of energy efficiency programs on retail electric rates and bills and the impact on fuel prices and bills.
3) §218c: Related to least cost integrated planning, regulated utilities must meet the public's need for energy services at lowest present-value life-cycle costs.
4) §202a: Related to state energy policy, 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. Also to identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least-cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply.

10.2 Electric Energy Efficiency

10.2.1 Background; Historic and Current Demand Reduction; Future Trends

The Vermont Legislature has long required that electric utilities include "comprehensive energy efficiency programs" as part of their responsibility to deliver electricity to their customers at least cost (30 V.S.A. § 218c). These programs have been incorporated into rates and funded through ratepayers' electric bills. Although utilities achieved some successes with early energy efficiency programs, the full potential of energy efficiency was not realized; an in-depth approach to reducing electricity usage was needed.[188]

In 2000, Vermont began administering these programs through energy efficiency utilities (EEUs). Efficiency Vermont (EVT) was created for this purpose; it operated under a contract with the PSB for all electric service territories other than Burlington.[189] In 2010, the PSB modified the structure of efficiency delivery by creating a longer-term "Order of Appointment" model that encourages the EEUs to better

[188] See PSB Order in Docket 5270 and DPS, *Vermont Electric Plan 2005*.

[189] Burlington Electric Department (BED) operates programs in its service territory; EVT serves the remainder of the state. BED's programs are required to have the same "look and feel" as EVT programs. Since April 2015, Vermont Gas Systems (VGS) has operated natural gas efficiency programs under a Board-approved Order of Appointment to serve as an EEU.

plan for long-term efficiency programs that transform markets, while allowing for a greater degree of regulatory oversight and transparent public processes to determine budget and performance targets.

Since 2000, the EEUs have acquired significant electric efficiency resources that have indeed met a significant portion of Vermont's electric needs, at a lower cost than would have otherwise been paid by ratepayers. Vermont currently leads the nation in our pace of acquiring electric energy savings through investments in energy efficiency. As summarized in a recent national benchmarking study commissioned by the DPS (and as shown in Exhibit 10-1), Vermont's electric EEUs deliver electric energy efficiency savings, above the median savings as a percent of sales, at the median levelized cost of energy saved of $0.03 per kWh.[190]

Exhibit 10-1. 2012 Benchmarking Results

	Spending as % of Revenue	Energy Savings as % of Sales	Summer Peak Demand Savings as % of Peak Demand	Retail Cost of Energy $/kWh	Cost of First Year Savings		Levelized Cost of Energy Savings *	Cost of Lifetime Savings **
					$/kWh	$/kW	$/kWh	$/kWh
All Benchmarked Median	2.70%	1.70%	0.90%	$0.12	$0.25	$1,825	$0.03	$0.02
EVT	4.00%	2.40%	1.30%	$0.15	$0.24	$1,705	$0.03	$0.02
BED	3.60%	1.90%	1.20%	$0.14	$0.26	$2,254	$0.03	$0.02

* Levelized cost of energy includes a capital revcovery factor.

** Cost of lifetime savings is annual spending divided by lifetime savings.

190 For example, see *Benchmarking of Vermont's 2011 and 2012 Demand Side Management Programs* (Navigant Consulting for the DPS) and the most recent *State Energy Efficiency Scorecard* (ACEEE).

Exhibit 10-2 shows the incremental annual MWh savings achieved by the electric EEUs. Recent savings from electric energy efficiency investments for EVT and BED combined translate into an annual total load growth savings of more than 2% per year.

Exhibit 10-2. Annual Incremental MWh Savings (2000-2014)

Year	Incremental MWh Savings
2000	28,760
2001	36,045
2002	38,821
2003	46,874
2004	47,750
2005	52,982
2006	62,317
2007	112,396
2008	151,702
2009	80,600
2010	110,524
2011	101,282
2012	110,179
2013	85,582
2014	91,146

10.2.2 Impact of Electric Efficiency Investments

Along with significantly reducing the amount of electricity Vermont utilities need to purchase to serve ratepayers, the savings acquired by the EEUs provide numerous benefits to Vermont's electric grid, Vermont ratepayers, and the Vermont economy. These benefits include:

- *Deferring or avoiding local or regional distribution or transmission projects.* Infrastructure construction is expensive — and if targeted appropriately, energy efficiency can be an effective alternative.
- *Reducing Vermont's share of the Regional Network Service (RNS) charge.* The New England states share the benefits and costs of reliability transmission projects completed in the region. These costs are significant, especially in the near term: in-progress, permitted, or planned transmission projects are projected to cost approximately $7 billion regionally, in addition to

the more than $4 billion of investment planned for the next 10 years.[191] Vermont pays these costs based on its contribution to the peak New England load. Investments in energy efficiency serve to reduce Vermont's share of the peak. Even small reductions in Vermont's load at the time of the New England peak create significant benefits for Vermont ratepayers, assuming that other New England states do not reduce a similar or greater amount of load at the same time. For 2016, avoided RNS costs are expected to be approximately $.015 per kWh saved.[192] In addition, the need for ancillary services provided by ISO-NE is shared across the region — another $.0066 per kWh saved. Taken together, each kWh saved avoids more than 2 cents in RNS and ancillary charges alone.

- *Generating local jobs.* Energy efficiency programs rely on local contractors, distributors, and retailers to facilitate service delivery. These stakeholders all benefit from increased private investment leveraged by efficiency.

- *Reducing carbon emissions from electricity generation.* Although Vermont has a relatively clean portfolio of electricity generation, energy efficiency reduces the need to purchase electricity from the regional market. Those generating units that run to deliver kWh required at the time of peak usage, often from natural gas or oil-fired generation of electricity, tend to produce significant carbon emissions — and efficiency investments reduce the need for these marginal generating units to be dispatched. The societal cost of carbon dioxide emissions was recently estimated at approximately $100 per ton of CO_2 equivalent.[193]

- *Significantly reducing electric bills for customers who participate in programs*, providing greater cash flow for commercial customers to reinvest in other business opportunities or needs, and providing more disposable income for residential customers to reinvest in the economy.

- *Securing revenues from the ISO-NE Forward Capacity Market* (FCM) for the benefit of Vermont, as discussed above, to be used for thermal efficiency investments.

- *Creating other, non-quantified benefits* for participants, such as increased productivity, safety, and comfort. Health benefits may also be present. For example, the transition to LED lighting (replacing fluorescent bulbs on burn-out or early retirement) moves in a direction towards greater energy efficiency and reduces potential for human exposure to mercury found in CFLs and other fluorescent bulbs.

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191 ISO-NE 2015 *Draft Regional System Plan*

192 The RNS charges are based on kW rather than kWh. However, a kWh value is reported here for ease of use.

193 Rick Hornby, et al, *Avoided Energy Supply Costs in New England: 2015 Report* (prepared for the Avoided-Energy-Supply Component Study Group, 2015) pp. 4-28, ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf

DPS estimates that from 2000 through 2014, EEU investments have avoided a cumulative total of more than 6.6 million MWh of electric power generation.[194] During this period the amount of electric energy saved by efficiency in each year has steadily increased, from about 50,000 MWh saved in 2000, to nearly 900,000 MWh saved in 2014. This rapid year-over-year growth in electricity savings is a natural consequence of the long-lived nature of the return on investments in efficiency; measures installed in any one year will reduce electricity consumption for several years to come — as many as 20 or 30 years for some measures. As EEU program budgets have grown and more efficiency measures have been installed, recurring electricity savings from ongoing investments have accumulated to the point that retail consumption in 2014 was more than 13% lower than it would have otherwise been without this history of efficiency investments. Similarly, Vermont's peak demand for electricity in 2014 — the level of consumption to which the grid must be built and maintained — was more than 100 MW lower because of EEU investments.[195]

In the absence of these efficiency savings, Vermont utilities would likely have relied on purchases from wholesale electricity markets to supply the power that was saved by efficiency investments. DPS estimates that the cumulative financial costs of those market purchases from 2000 through 2014 would have totaled more than $420 million (in 2015 dollars), an amount that ultimately would have otherwise been collected from ratepayers. These avoided power supply costs can be broken down into two separate categories: avoided market purchases of electric energy, and avoided market purchases of electric capacity.

Avoided electric energy purchases have been the dominant source of cost savings for electric utilities, totaling around $386 million cumulatively from 2000 through 2014 (in 2015 dollars). *Avoided electric capacity purchases* have historically been a smaller source of cost savings for electric utilities, totaling around $35 million cumulatively from 2000 through 2014 (in 2015 dollars). In addition to avoiding wholesale market purchases, EEU investments have also reduced the charges that utilities must pay to cover the revenue requirement of ISO-NE under the auspices of the Open Access Transmission Tariff (OATT). These "Regional Network Service" (RNS) charges can be thought of as the local utility's share of the overall cost to maintain and upgrade the bulk transmission facilities relied on by all wholesale market participants in the region. Since 2000, Vermont utilities have paid more than $500 million in RNS charges (in 2015 dollars). DPS estimates that, were it not for EEU investments during this period, Vermont ratepayers would have paid about $50 million more for electric service over this time than was actually paid.

Exhibit 10-3 presents DPS's estimates of the total wholesale electricity cost savings in each year from 2000 through 2014 that have resulted from the avoided market purchases of electricity (energy and capacity) and avoided RNS charges that past investment in efficiency has made possible. In this table, it can be seen how the cost-savings benefit of efficiency measures installed in a given year have recurred over subsequent years. For example the majority of the wholesale cost savings in 2005 were the result of measures installed in previous years (some having been installed even before 2000), but which were still saving electricity many years later. Thus, the wholesale electricity cost savings from EEU investments

[194] For reference, Vermont utilities have sold almost 85 million MWh over this time.

[195] For reference, Vermont's peak demand in 2014 was around 950 MW.

have generally increased year over year as the portfolio of measures installed by EEUs has grown and annual EEU investments have increased.

Exhibit 10-3. Avoided Electric Costs and Electric EEU Expenditures, By Year (Millions of 2015 Dollars)

Year	Avoided Wholesale Costs[196]	Collected from Ratepayers[195]
2000	$3.0	$11.3
2001	$4.6	$12.7
2002	$6.0	$14.1
2003	$11.8	$15.8
2004	$15.3	$17.6
2005	$27.2	$21.2
2006	$25.5	$26.4
2007	$33.5	$24.6
2008	$51.4	$33.0
2009	$34.4	$33.7
2010	$45.4	$39.6
2011	$48.2	$42.8
2012	$42.1	$42.3
2013	$58.8	$43.6
2014	$65.8	$47.8
2000-2014	$473.0	$426.5
Expected Value of Past Investments as of 2015	$400 - $480	N/A

In contrast to the $421 million in avoided market purchases of electric energy and capacity, and the approximately $52 million of avoided RNS charges (totaling $473 million in wholesale cost savings), Vermont ratepayers have paid about $427 million (in 2015 dollars) to fund the programs that avoided these wholesale costs[197]. Consequently, there has been a cumulative net savings to ratepayers (as a whole) of more than $50 million over this time (in 2015 dollars).[198] However, this sum does not capture the full

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[196] Avoided wholesale costs of electricity include avoided electric energy purchases, avoided electric capacity purchases and avoided RNS charges. The MWh savings used to calculate these totals exclude the savings associated with Customer Credit programs. Energy Efficiency Charge revenue associated with Customer Credit programs is also excluded from total collections from ratepayers.

[197] Individual customers that participate in EEU programs have also borne some of the upfront costs of reducing their electricity usage. From 2000-2014 these participant costs have totaled around $200 million (in 2015 dollars). This amount was not however, passed on to ratepayers.

[198] In addition to avoided wholesale costs, efficiency investments are also likely to have avoided at least some amount of the ongoing cost of maintaining and expanding local transmission and distribution systems. Exactly how much T&D cost have been avoided by EEU investments is a complicated question requiring elaborate and intricate

value of EEU investments made since 2000, since many of the efficiency measures installed in the past will continue to save wholesale electricity costs for several years to come without the need for any additional program funding. As of 2015, the EEU portfolio of active efficiency measures is expected to save a total of almost 6 million MWh over the next three decades — almost as much electricity as has already been saved since 2000 — without the need for any additional investment. DPS estimates that the present value (in 2015 dollars) of the wholesale costs savings associated with this continued electricity savings is in the range of $400 to $480 million. Thus, looking forward, DPS expects that EEU investments will continue to reduce utilities' wholesale expenses, and therefore ratepayer costs, in excess of the cost to fund the programs. On top of avoided wholesale costs, efficiency investments have also avoided some amount of the cost of maintaining and expanding local transmission and distribution systems since 2000, though how much exactly is difficult to say without additional elaborate analysis.

In 2011 the DPS commissioned Optimal Energy and Synapse Energy Economics to conduct a modeling analysis to determine the economic impact, in terms of both dollars and jobs, to Vermont of EEU electric energy efficiency investments. Many of the above factors cited above as benefits were included, as were the immediate negative economic effects of the rate impact of the state's energy efficiency charge. The study found that energy efficiency investments generate significant net positive economic activity throughout Vermont, through the purchase and installation of energy efficiency goods and services, the administration of the program itself, and net energy savings to ratepayers and participants. Households that participate in the program save on energy costs, and therefore can spend additional money in the local economy, spurring job growth. Businesses have lower energy costs, which improves their bottom line and enables them to be more competitive and to expand production and related employment. The investment in efficiency in itself also generates economic activity to the extent that equipment is produced, sold, installed, and/or maintained by Vermont businesses.

Using a single year of electric efficiency investments based on the approved 2012 EEU budget, the study found that for every $1 million of public electric-efficiency investment by the EEUs, $4.6 million of present value benefit is returned to the state. The net change in employment in Vermont attributable to the program's total spending was approximately 46 job-years per $1 million (including direct, indirect, and induced economic activity that impacts employment). The study also found that every dollar spent on EEUs delivered electric efficiency that increased gross domestic product by a multiple of more than five. These results are unequivocal: public investments in electric efficiency are beneficial to the Vermont economy.

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analysis that has not been conducted for Vermont in almost a decade. For reference, in 2014 Vermont utilities spent over $143 million on local T&D.

Exhibit 10-4. Leverage of 2012 Electric Efficiency Program Spending

Total budget (2011 $)	Job-years per million $	Net present value of energy savings per $ budgeted
$39.1 million	46	$4.6

It should be noted that a significant portion of these benefits are not societal benefits — rather, they occur within the Vermont economy itself. For instance, as described above, it is estimated as of 2011 that for every kWh of electricity saved, Vermont avoids approximately $0.021 of RNS and ancillary service charges from ISO-NE. The RNS charge is the share of regional transmission costs that Vermont must pay, based on its monthly peak demand. Efficiency implementation lowers Vermont's share of these regional costs. While Vermont avoids those costs, society does not — other New England states must pick up the difference. However, Vermont ratepayers can avoid paying them when the state outperforms its region. The recent growth of solar PV is moving the daily peaks to later in the evening. To remain effective at reducing RNS charges, energy efficiency measures targeted at peak reduction must be reviewed and adjusted regularly to ensure the coincidence factors are corrected over time for changes in the peak.

The economic impact studies above show that electric efficiency investments have a large positive impact on the economy. The full results and methodology of the later *Economic Impacts of Energy Efficiency Investments* study can be found in at the DPS's website[199].

Recommendations

(1) The DPS should collaborate with energy efficiency utilities and other stakeholders to better document and communicate the benefits of electric efficiency investment to the Vermont Legislature, ratepayers, and other stakeholders.

(2) The DPS should perform economic impact studies at least every three-year budget cycle to measure effects of efficiency investments.

(3) When advocating for changes to the energy efficiency charge (EEC) to the PSB, as per §209(d)(3)(b) and §30 V.S.A. §209(f)(14), the DPS should continue to review the EEC for unrealized energy efficiency potential and adjust the EEC as necessary in order to realize all reasonably available, cost-effective energy efficiency savings while also taking into consideration the cost impact of energy efficiency programs on retail customer rates and bills.

[199] Optimal Energy, Inc., *Economic Impacts of Energy Efficiency Investments in Vermont — Final Report* (for Vt. DPS, 2011), publicservice.vermont.gov/sites/psd/files/Topics/Energy_Efficiency/EVT_Performance_Eval/Economic%20Impacts%20of%20EE%20Investments_2011.pdf

10.2.3 ISO-New England and Forward Capacity Markets

Although there appears to be adequate generation capacity to serve summer peak needs in New England, significant risks to the continued reliability of the region's power grid do exist. These risks include New England's dependence on natural gas as a fuel to generate a large portion of its electricity, and impending retirements of aging resources. The ISO-NE Forward Capacity Market (FCM) was developed, and continues to be enhanced, to ensure that the region will have sufficient generating capacity to meet its peak capacity needs. It does this by providing guarantees for future revenues to entities that commit to providing or avoiding peak capacity at a future date.

The FCM allows not only generators, but also demand reduction, to bid into the market — so that ISO-NE may rely on either more capacity or less use in meeting projected demand. Vermont's portfolio of efficiency savings is submitted to the FCM, and is used to help meet the region's need for capacity. Revenues from participating in the market far exceed the costs of participating, including compliance with rigorous measurement and verification standards. These revenues have been directed by the Legislature to be used to support unregulated heating and process fuel efficiency programs (see Chapter 7).

Energy efficiency is a valuable capacity resource in the FCM because it is embedded in the system and is not intermittent. In planning for the region's capacity requirements, ISO-NE forecasts annual and peak energy consumption 10 years into the future. Regional discussions continue between ISO-NE, the New England States Committee on Electricity (NESCOE), and public utility commissions to enable regional transmission planning to better reflect the region's collective investment in energy efficiency resources and the resulting reduction in load. At present, ISO-NE collects actual measure level kWh and kW installation data from regional program administrators to help improve forecasting through the ISO-NE Energy Efficiency Forecasting Working Group.

There may be ways to further optimize Vermont's participation in the FCM. For example, it may be possible to optimize FCM revenues (and mitigate rising RNS charges) by placing a greater emphasis on certain measures. Such a strategy could include deploying measures that save energy at peak times, and weighting peak demand reduction goals and financial incentives for the EEUs appropriately as part of their quantifiable performance indicators (QPIs).

The FCM is designed to ensure that there are sufficient resources to meet expected peak demand and the necessary reserve margin by paying resources — which can include generation, energy efficiency, and demand response — to be available when called on. The costs associated with the FCM are assigned to each utility based on its contribution each year to the system-wide peak hour. To the extent that energy efficiency measures limit growth in peak demand, FCM charges to Vermont utilities will be less than they would have been otherwise. Even measures that do not qualify to bid into the FCM as a resource, such as peak shaving resulting from smart rates or volt/VAR reductions, reduce capacity charges to utilities to the extent that these measures coincide with system-wide peak.

Recommendations

(1) *The state should maintain VEIC and BED's participation in the FCM on behalf of the state's ratepayers.*

(2) *Maintain the DPS's and electric EEUs' participation in ISO-NE efficiency forecasting efforts to ensure efficiency is appropriately reflected in ISO-NE's long-term planning.*

(3) *The DPS should advocate to the PSB for the appropriate weight and financial incentives for summer/winter peak savings goals in electric EEU's QPI's.*

10.2.4 Geographic Targeting of Energy Efficiency Investments

Energy efficiency investments not only reduce annual electric consumption; they also reduce peak consumption. Peak consumption can be costly to cover in the market; it also affects the RNS rate charged to all Vermonters for pooled transmission facility projects. Peak reduction has the additional benefit of reducing the need for transmission and distribution infrastructure — if it occurs in areas where the system is constrained by load growth. In recognition of this value, the PSB in 2006 modified the guidance provided to EVT. It directed a significant portion of the state's energy efficiency investments to specific geographic areas of the state.

The concept behind this *geotargeting* (GT) was to place incremental energy efficiency investment into areas that are good candidates for deferring or avoiding transmission and/or distribution (T&D) upgrades. Four areas were initially geotargeted. Three of the original areas, plus one new area, were selected for the 2009-2011 time frame. These areas were the Southern Loop area from Brattleboro to Manchester, the North Chittenden County area, St. Albans, and Rutland. The 2012-2014 time frame also targeted the St. Albans and Susie Wilson Road areas.

The DPS completed an evaluation of GT impacts in 2011.[200] The study found that GT works: it is possible to quickly ramp up energy efficiency programs to acquire significant peak demand savings in specific geographic areas. The study further enhances the credibility of energy efficiency as a resource acquisition strategy equal to other resource options.

Ongoing results have shown that the GT program should continue — but there remains room for improvement. The Vermont System Planning Committee (VSPC) has been charged with, among other things, evaluating and recommending the systematic and strategic use of energy efficiency investments (through GT programs or some other vehicle) to avoid or defer transmission investments. Also, to streamline the Demand Resource Plan proceeding, the funding of GT is to be considered, to the extent

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[200] Navigant Consulting, *Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program* (for Vt. DPS, 2011), publicservice.vermont.gov/sites/psd/files/Topics/Energy_Efficiency/EVT_Performance_Eval/Navigant_Vermont GeoTargeting 2010 Process Impact Evaluation FINAL .pdf

possible, in the triennial EEU budget-setting process[201]. The VSPC is now the appropriate venue to vet GT area selection, ensuring that energy efficiency is fully utilized as a least-cost alternative to transmission infrastructure development to the maximum extent otherwise allowed by regional market rules and by the reliability standards of the North American Electric Reliability Corporation (NERC).

The concept of geographically targeting energy efficiency also applies to the natural gas system. VGS's Order of Appointment for delivering natural-gas energy efficiency requires VGS to participate in the VSPC on an as-needed basis, and to reduce natural gas capacity requirements through peak day and base load reduction and management in targeted areas, if applicable. The tools and process developed by the VSPC to identify potential electric GT areas may have value for identifying and deferring natural gas transmission investments.

Recommendations

(1) *The DPS should continue to facilitate VSPC consideration of efficiency as a least-cost resource to defer or avoid electric transmission and distribution infrastructure development.*

(2) *The DPS and other stakeholders should utilize the expertise of the VSPC for determining appropriate methods for estimating the benefits of avoided distribution and transmission costs that are used in cost-effectiveness screening.*

(3) *The DPS should facilitate VGS's initial participation in the VSPC, as needed, and investigate the benefits of modifying the VSPC's tools for identifying and selecting GT areas for use on the natural gas system.*

10.2.5 Sources of Electric Efficiency and Efficiency Utility Funding

Funding for electric efficiency program delivery is collected through ratepayers' electric bills, via a separately stated energy efficiency charge (EEC). The PSB determines the EEC, largely via a process of setting overall energy efficiency budgets for the EEUs. This process was most recently completed in 2014, to set firm budgets for the 2015-17 program cycle and prospective budgets for 2015 through 2034.

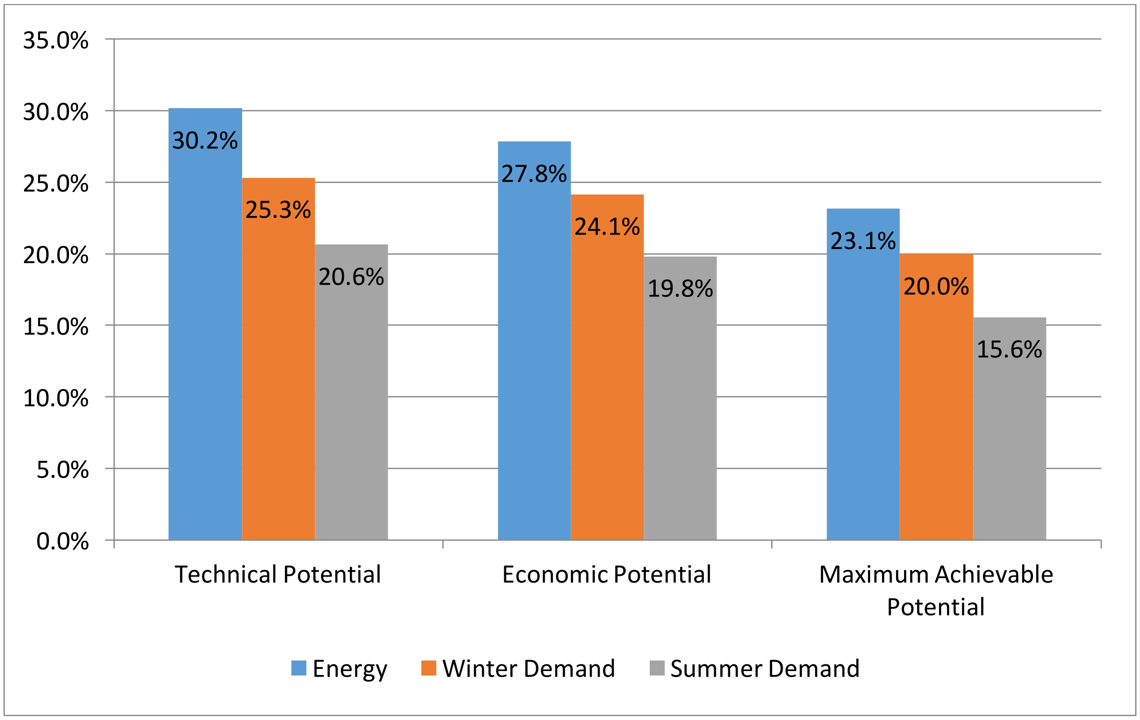
The PSB balances a number of legislatively directed considerations when it determines the three-year budget and approves efficiency programs delivered by EEUs. As cited above in the Goals and Objectives subsection, many of these directives can be found in 30 V.S.A. § 209(d)(4) and 30 V.S.A. § 209(e). They include the directive to acquire "all reasonably available, cost-effective energy efficiency savings," with particular emphasis on "reducing the size of future power purchases; reducing the generation of GHGs;

[201] Public Service Board Order of September 22, 2014 in EEU 2013-05 revisions to the Process and Administration of an Energy Efficiency Utility's Order of Appointment Section II.1.A.c: "To the extent possible include consideration of the effects on overall DRP budgets and QPIs of geographically targeted energy efficiency budgets and services that may address distributed utility Supply Problems and/or transmission Reliability Deficiencies."

limiting the need to upgrade the state's transmission and distribution infrastructure; [and] minimizing the costs of electricity."

To inform the PSB decision regarding budgets, the DPS conducted an update to its energy efficiency potential study (originally completed in 2011). The update determined that cost-effective achievable energy efficiency potential is 23.4% of forecasted 2033 MWh sales (see Exhibit 10-5).[202]

Exhibit 10-5. Electric Energy Efficiency Potential (Percentage of Forecast 2033 MWh and MW Consumption), All Sectors Combined



These significant cost-effective efficiency resources can be "acquired" by business and residential ratepayers though private investment or efforts supported by various ratepayer-funded programs and offerings. Vermont already offers many programs via the EEU model, and the DPS works with the EEUs to support continued innovation and design of the most effective programs to assist ratepayers in achieving efficiency savings.

In its 2013-14 Demand Resource Plan proceeding to develop electric efficiency budgets, the PSB ordered a modest increase in budgets for the three-year period that sets Vermont EEUs on a path to acquire all reasonably available cost-effective energy efficiency. The budgets are expected to yield significant electric resource savings for Vermont ratepayers. It is important to note that the PSB did not order the acquisition of *all* cost-effective potential efficiency measures, because the immediate rate impact considerations and the pace of program expansion limited *reasonable* efficiency budgets. Further, the maximum achievable

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[202] GDS Associates, Inc., *Electric Energy Efficiency Potential for Vermont* (for Vt. DPS, 2013), publicservice.vermont.gov/sites/psd/files/Topics/Energy_Efficiency/2013 VT Energy Efficiency Potential Study Update_FINAL_03-28-2014.pdfh

cost-effective potential assumes a 100% incentive in place for efficiency measures — a level that is neither necessary nor reasonable under sound program design.

Finally, the PSB's budget order for the EEUs 2015-2017 programs included focused research and development budgets to allow for thorough consideration and piloting of behavior and conservation programs intended to leverage digital meter data and the advanced metering infrastructure (discussed below). *Energy efficiency* and *energy conservation* are often used interchangeably, but there are some differences. At the most basic level, energy conservation means using less energy and is usually a behavioral change, like turning your lights off or setting your thermostat lower. Energy efficiency, however, means *using energy more effectively*, and is often a hard-wired technological change. Energy efficiency measures the difference between how much energy is used to provide the same level of comfort, performance, or convenience by the same type of product, building, or vehicle.[203]

Exhibit 10-6 shows the energy efficiency utility budgets approved for collection via the EEC since 2001 and projected through 2034.[204]

[203] Natural Resources Canada, www.nrcan.gc.ca/energy/efficiency/buildings/eeb/key/3969

[204] Total budgets include funds collected from ratepayers for program delivery by both EVT and Burlington Electric Department, evaluation, efficiency fund management, and compensation. Forward budgets are approved on a three-year basis (2015-2017 budgets are firm, whereas future budgets are subject to revision based on future Demand Resource Plan proceedings).

Exhibit 10-6. Electric Energy Efficiency Utility Budgets Collected Via the Energy Efficiency Charge (2000-2034)

Historic		Board Approved		Projected	
Period	Amount	Period	Amount	Period	Amount
2000	$8,674,914	2015	$52,217,314	2018	$58,327,684
2001	$10,760,991	2016	$56,212,779	2019	$59,389,517
2002	$13,141,733	2017	$58,736,340	2020	$61,013,058
2003	$14,000,000			2021	$63,987,570
2004	$16,224,477			2022	$64,952,892
2005	$17,500,000			2023	$66,668,424
2006	$19,500,000			2024	$69,973,773
2007	$24,000,000			2025	$71,064,244
2008	$30,750,000			2026	$72,841,863
2009	$30,688,000			2027	$75,879,971
2010	$33,485,000			2028	$76,960,210
2011	$38,500,000			2029	$78,884,927
2012	$40,100,000			2030	$82,655,394
2013	$42,800,000			2031	$85,302,626
2014	$45,900,000			2032	$85,158,869
				2033	$88,779,400
				2034	$89,576,446

10.2.6 Self-Managed Programs

Energy efficiency acquired by companies provides benefits to both the firms (through increased productivity) and society at large (through shared electric grid and environmental benefits). It is therefore in the public interest to acquire all reasonably available cost-effective energy efficiency, through whichever programmatic structures allow and entice firms to acquire it. Most Vermont companies are well served by the energy efficiency utility structure, in which they pay an energy efficiency charge (EEC) and are able to take advantage of technical and financial assistance from the EEUs. For example, from 2012 to 2014, Vermont's 300 largest businesses[205] used approximately one third of all the electricity

[205] Based on estimated annual consumption, not including the Self-Managed Energy Efficiency Program and Customer Credit Program participants.

consumed in Vermont. Of 98 manufacturing firms in this group, 75 made the business decision to participate in energy efficiency programs during these three years; over 450 individual projects were completed with these firms. The investments made at those 75 firms from 2012-2014 are projected to yield an average net lifetime return on investment (L-ROI)[206] of 116%. That is, for every dollar invested in energy efficiency, the average gross monies returned on the investment to these companies is $2.16, for a net return of $1.16.

For these firms, investments in energy efficiency will deliver projected benefits for the lifetime of the efficient equipment (typically more than 12 years). For this analysis, benefits include only the projected electricity and fuel savings and water savings associated with the installed measures (reduced operating and maintenance costs, increased productivity, and non-energy benefits are not included). For participating firms which see a positive L-ROI, efficiency measures improve cash flow and allow these firms to spend less on energy and have more to invest in other capital improvements, new products and services, and their employees.

For a smaller number of firms, retaining control over energy efficiency spending while forgoing some EEU assistance may be a viable option. Energy Savings Accounts (see below) are the one significant current programmatic avenue to address this second group of firms. Eligibility requirements limit participation in the Self-Managed Energy Efficiency Program and Customer Credit Program; the CEP suggests that these two later programs remain unchanged.

Energy Savings Accounts

Recognizing that certain business customers already may be committed to energy efficiency and have considerable expertise in implementing it, the *Energy Savings Account* (ESA) option allows eligible business customers the option to self-administer their own efficiency efforts instead of participating in EEU services and initiatives. As required by Vermont law, in 2009 the PSB established a process by which an electric customer that pays an average annual EEC of at least $5,000 may apply to the Board to self-administer energy efficiency using an ESA. Customers pay their EEC as usual, and can then apply for reimbursement of qualified expenses from their own funds. The law provides that the ESA contain a percentage of the customer's EEC payments for use in making energy efficiency investments, and that the remaining portion of the charge be used for system-wide benefits. (These provisions are codified in 30 V.S.A. § 209(d)(3)(B).) ESA program participation requirements and guidelines are posted on the Board's website[207], and were revised in 2014.

While the current ESA program offers benefits and may be of interest to potential participating customers, not all potential interested ESA customers have the capacity to administer and navigate it.

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[206] Net L-ROI = (value of returned benefits minus participant costs) divided by participant costs, where *returned benefits* equals the value of lifetime energy (electricity and fuel) and water savings, not including monetary savings associated with reduced maintenance or increased productivity; and where *participant costs* equals the sum of participant costs including estimated EEC contributions and net project costs (total project costs less EVT incentives).

[207] psb.vermont.gov/sites/psb/files/orders/2014/2014-06/Attachment%20A%20ESAprogramDesign2014.pdf

Participation requires both energy efficiency expertise (including how to use various tools developed for use by the EEUs, such as the cost-effectiveness screening tool) and administrative capacity to handle the extensive requirements regarding how funds may be used and how savings are documented. In part due to these barriers, to date there have been only two participants in the ESA program.

As part of its research for a report due to the Legislature under Act 199 of 2014[208], the DPS has identified that there are several options worth exploring for changes to the ESA program. These options include changing to a performance-based structure, similar to what is in place for the EEUs, rather than a spending-based structure. For example, if a firm can achieve savings as cost-effectively, or more so, in its own facility than the same investment could have achieved through the EEU, the firm should be encouraged to do so.

Another option is to consider other more flexible options for a customer's ESA program cash flow and cash management. For example, a firm may be more likely to pursue efficiency if it has greater latitude in how to apply available ESA funds, and in how those are accounted for financially. In addition, EEUs currently provide some technical assistance to ESA-participating firms, and those firms' efficiency acquisition counts towards the EEU's performance goals; further investigation could illuminate how to cost-effectively provide optimal level of both EEU and firm assistance to reduce costs.

For example, this could develop into an analog to the "special contracts" that distribution utilities can provide to deliver unique services to their customers; EEUs could develop individualized treatments of EEC and assistance for each participating ESA firm. By doing so, it may be possible to keep elements of the technical assistance and account management engagement model intact, while addressing issues for some large customers and providing greater control over their EEC. Each of these potential changes needs to be investigated and evaluated through dialog with stakeholders before it is implemented, in order to design a program that advances the public objective: cost-effective energy efficiency acquisition without lost opportunity resulting from program design.

Recommendations

(1) Over the next year, the DPS should work with the Agency of Commerce & Community Development, the Regional Development Corporations, the EEUs, and other stakeholders to investigate updates to the Energy Savings Account program, including consideration of changes in the ESA program structure to allow it to work for a greater variety of firms, as well as the possibility of "special contracts" that work for particular firms.

10.2.7 Challenges to Increasing Electric Efficiency

The pace at which Vermont acquires all reasonably available cost-effective energy efficiency is limited by rate impacts, a responsible expansion pace of programs, and the actual cost-effective potential. Further, the state must be a responsible advocate for setting incentive and financing levels appropriately, to

[208] www.leg.state.vt.us/docs/2014/Acts/ACT199.pdf

encourage investments in energy efficiency without overspending public resources to get the desired outcome. The state also should encourage innovation through the deployment of emerging technologies, while continuing to be an advocate for a portfolio that balances two important objectives: low-cost saved energy and long-lived measures.

For example, in 2012 and 2013 Vermont led the region with the lowest levelized cost of saved energy, at $0.035 per kWh — and also led the region with the lowest lifetime cost of saved energy, at $0.030 per kWh. Technologies with long measure lives persistently deliver benefits over time, avoid the need for frequent replacement, and contribute to a longer weighted-average measure life for the portfolio (Vermont's 2012-13 weighted-average measure life of approximately 11.5 years was second longest in the region)[209].

Vermont will continue to explore new ways to integrate energy efficiency into supply-side resource assessments, including evaluating the behavioral/conservation programs currently being tested by EEUs under the resource acquisition research and development EEU budget category, which is intended to leverage the advanced meter infrastructure and digital meter data. Examples include EVT's residential Home Energy Report and commercial Continuous Energy Improvement test programs. Another is Burlington Electric Department's partnership with UVM, Burlington's Community Economic Development Office (CEDO) and the UVM Clean Energy Fund, to test whether advanced technologies and competition among peers can result in a higher degree of energy awareness and lower electric energy consumption.

Internal program efficiencies should also continue to be monitored to ensure that Vermonters are getting top performance from their EEUs for their public investment. To that end, the DPS has recently collaborated with the EEUs to propose service quality reliability plans (SQRPs) and program implementation efficiency quantifiable performance indicators (QPIs) to the PSB. These indicators are intended to ensure continuous improvement of electric efficiency service delivery— and efficient delivery of efficiency programs.

Recommendations

(1) The DPS should encourage and facilitate innovative program designs and strategies to increase electric efficiency resource acquisition.

(2) The DPS should complete its planned process and impact evaluations of the behavior and conservation programs funded with EEU resource-acquisition research and development budgets during the 2015-2017 performance period, in order to inform the DRP that will set budgets and goals for the 2018-2020 performance period.

209 Northeast Energy Efficiency Partnership, Regional Energy Efficiency Database reported data for years 2011 through 2013, reed.neep.org/StateDocs-VT.aspx

(3) The DPS should work with the EEUs to continue to revisit, review, and strengthen the QPI and SQRP framework. This should include weighting summer/winter peak savings goals for electric EEU's appropriately, and working with EEUs to develop and weight a new QPI that reflects cumulative lifetime savings.

10.3 Load Management

10.3.1 Advanced Metering Infrastructure (AMI)

The technology associated with advanced metering infrastructure (AMI) and digital meters has significant potential to increase system reliability and load management capabilities. *Smart grid* generally refers to a class of technology that is being used to modernize utility electricity delivery systems. These systems are made possible by two-way communication technology and computer processing. This technology includes smart meters, which are digital meters that play a key role in enabling the two-way communications that characterize a smarter grid.

The potential benefits are that a smart grid would enable utilities and their customers to track and manage the flow of energy more effectively (including the cost of electricity at a given time), curb peak demand, lower energy bills, reduce blackouts, and integrate renewable energy sources and storage to the grid (including electric and plug-in hybrid vehicle batteries). The smart grid also has the potential to increase energy efficiency, thereby reducing environmental impacts of energy consumption; and it can empower consumers to manage their energy choices.

Many Vermont utilities have already begun the process of replacing old analog meters with new digital units. As of the drafting of this CEP, more than 80% of the state's electric meters are digital. The U.S. DOE, under the American Recovery and Reinvestment Act (ARRA), established a $3.4 billion grant pool to accelerate the adoption of smart grid technologies throughout the country while creating jobs to stimulate the economic recovery. In October 2009, Vermont's electric utilities were awarded approximately $69 million in ARRA funds to deploy smart grid technology. This was the largest per-capita smart grid grant awarded to a state. The statewide grant application, known as eEnergy Vermont, was filed by Vermont Transco on behalf of all Vermont distribution utilities, with the support of the DPS, EVT, and the Office of Economic Stimulus and Recovery, as well as Vermont's Congressional delegation.

This grant has provided approximately half the cost of $138 million in infrastructure improvements that utilities have made across Vermont. The project has moved Vermont toward development of a statewide digital grid, using technology to convert the electric infrastructure from a one-way delivery system (conveying electricity to consumers) to a two-way communication system able to relay information about usage, voltage, existing or potential outages, and equipment performance between the customer and the utilities.

Recommendations

(1) *The DPS should monitor PSB docket 7307 and the pending Proposal for Decision for establishing uniform consumer privacy and cybersecurity expectations for utilities, and consumer choice policies.*

(2) *The DPS should also monitor PSB Docket 8316 for resolution related to AMI utilities other than GMP to take advantage of the new data-driven services being offered by the EEU.*

How AMI Works

Digital metering systems deployed in Vermont and other parts of the country typically have three components: a digital meter located at the customer premises, a communications network between the meter and the utility, and a head-end system located at the utility office.

- **Digital Meters.** Digital meters record and store interval usage data and billing data, permit demand readings, read power supply status, and determine electric service connectivity at the premises. Digital meters relay energy use data to and within a customer's home or business via web presentment options or in-home displays (IHDs). Most of Vermont's digital meters are compatible with Zigbee communication devices, which are the industry standard for wireless home area network (HAN) communication between digital meters and IHDs.

- **Communications Network.** The communications network between the meter and the utility has the ability to transmit data, control signals, and send price alerts from the utility to the meter. *Power line carrier* (PLC) and *radio frequency* (RF) are the two primary types of communications networks used in Vermont. VEC and WEC currently use a PLC system. With PLC networks, the utilities use technology in which signals are sent over the electric line from the utility to communicate with the meters. PLC systems operate something like cable television systems: all meters on a common distribution line from the electric substation monitor a single broadcast channel, on a fixed frequency transmitted over the electric power conductor.

  In an RF network, the utility uses radio frequencies to broadcast and communicate with the digital meters installed at customer facilities. GMP, BED, and SED have RF systems, in which two-way communication between the utility and the meter is enabled by low-power RF chips in the meters at customers' premises. RF does not require a line of sight to communicate with concentrators — each meter becomes a repeater, providing path diversity to communicate around local obstacles. Since alternative communication paths are available, the network is self-healing — it still operates when one device becomes inoperable or a connection is impaired.

Some Vermonters have raised concerns regarding the health impacts of RF-based meter communications systems. The Vermont Department of Health performed a review of the issue in 2012, and the results are available on the Department's website[1]. The DPS has also supported customer opt-out policies to allow consumers to choose not to accept the new meter infrastructure.

- **Head-End System.** The *head-end system* is made up of the hardware and software used to process the collected electricity usage data. This system transmits data, control signals, and price alerts on the communication network to the meters. The head-end system includes the *master station*, the *meter data management system* (*MDMS*), and the *web presentment system*. The master station performs several important functions, including the management of the communications network, scheduling and collection of meter readings, and coordination of routine customer and meter changes to ensure that all meters are read. The master station is flexible enough to support a utility's growing needs to provide network monitoring, control of grid management, and reporting capabilities. The MDMS is a sophisticated database or repository for the enormous amount of data that is recorded from the meters each day. Internet web presentment systems provide the consumer with tools to view and interpret the stored data to better manage their energy consumption. Consumer benefits made possible by the head-end system may include allowing customers to perform their own rate comparisons — that is, to determine which rate is best for their service profile. Customers also may benefit from usage history comparison and analysis and links to energy-saving programs, tips, and strategies.

10.3.2 Strategies for Load Management

AMI will be a key energy management tool for policymakers, utilities, and consumers — but AMI technology will not by itself reduce customer demand for electricity. If electric efficiency is to increase through this technology, customers must either respond to price signals or change their behavior based on automated feedback they receive.

The presence of widespread AMI in Vermont is noteworthy. AMI can improve grid analytics, support advanced demand response, support next-generation efficiency, and enable energy savings from new technologies such as smart thermostats to be readily measured. Smart thermostats, for example, have potential to generate energy savings from more efficient operation of heating systems; they can enable demand response by controlling HVAC systems during peak events, and the savings from the events can be measured with AMI.

10.3.3 Demand Response

Energy efficiency refers to using less energy at any time, including peak periods, to provide the same or improved level of service to the energy consumer in an economically efficient way. In contrast, *demand response* centers on customers changing their normal consumption patterns, in response to changes in the price of energy over time, or to incentive payments that reward lower electricity use when prices are high or system reliability is in jeopardy. Because most demand response programs in effect today are event-driven, customers tend to assume that demand response events occur for limited periods that are called by the grid operator; but *critical peak pricing* (CPP) and *real-time pricing* (RTP) are growing in prevalence and impact. Many demand response programs are designed primarily to curtail or shift load for short periods of time — but those programs that educate customers about energy use with time of use (TOU) rates, smart rates, and energy use feedback can also produce measurable reductions in total energy use and cost.[210]

Further, the presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed *ancillary services*[211] and include voltage regulation, power factor control, frequency control, and spinning reserves.[212] *Spinning reserves* refers to the availability of additional generating resources that can be called on within a very short period of time.

In a system where utility operators or third-party aggregators have the ability to control end-use loads, it is typical for utilities to manage demand in such a way that customers do not notice a change in the performance of their equipment. Because of this, utility-controlled equipment has potential to become a form of spinning reserve — and when placed at the disposal of system operators and smart control technologies, this becomes an important resource for delivering demand response during high-cost periods, or when the grid is at or near its operating capacity and may be at risk for system failures.

As technology evolves, it will be important for federal appliance standards to require installation of control technologies and two-way communication capability in new major appliances such as refrigerators, water heaters, furnaces, heat pumps, air conditioners, dishwashers, clothes washers, and

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[210] U.S. EPA, *Coordination of Energy Efficiency and Demand Response*, www2.epa.gov/energy/coordination-energy-efficiency-and-demand-response

[211] One of a set of services offered in and demanded by system operators that generally address system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves, and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

[212] Jim Lazar and Wilson Gonzalez, *Smart Rate Design for a Smart Future* (Regulatory Assistance Project, 2015), www.raponline.org/document/download/id/7680

clothes dryers, so they can be a demand response resource for managing peak-time loads (in both the summer and winter) and they have the capability to automatically respond to changing smart rates.

Importantly, as the demand for space cooling increases due to increasingly hot summer temperatures, control technologies for cooling, combined with other spinning reserves, can help keep buildings and occupants cool while also mitigating peak time loads coincident with hot weather. To this end, control technologies for electric space heating and cooling, specifically heat pump technology, are a high priority. Of equal importance related to managing peak loads and keeping buildings cool are other building-shell, weatherization, and ventilation strategies, along with design and passive cooling techniques like shade-promoting landscaping and siting considerations to improve shade and ventilation, cool roofs, and more reflective external walls.

Recommendations

(1) *The DPS should continue to investigate DU and EEU roles and coordination when designing, delivering, and supporting demand response initiatives.*

(2) *The DPS should encourage the adoption of equipment and appliances that can respond to utility signals, for example through DU and/or EEU incentives for customers and rate designs that allow participating customers to save money. DUs and EEUs should coordinate activities as the market evolves to advance smart rates and controllable equipment as a demand response strategy.*

10.3.4 Smart Rates

Smart rates are one way to balance supply and demand, reduce costs, and improve the environmental performance of Vermont's power supply.[213] Utilities that deploy smart rates vary the price of electricity to more accurately reflect their own costs in providing electricity to customers. Although there are different specific ways of designing smart rates, utilities typically charge lower rates during times of low demand, usually overnight, and higher rates during peak demand, usually afternoon and evening or on particularly hot or cold days. One key feature of smart rates is overall bill stability: for the average

[213] For a complete discussion of smart rates, see *Smart Rate Design for a Smart Future* (RAP, 2015), www.raponline.org/document/download/id/7680

customer, total annual bills will remain nearly the same if their usage patterns do not change. Customers can choose to shift their consumption to lower-priced times to reduce their bills.

Traditional rates reflect highly averaged costs — e.g., across diverse customers in broad rate classes, and over many different hours of the year. Smart rates more accurately reflect the costs that individual customers are responsible for incurring to the system. This ensures a fair distribution of costs among customers; it also has the potential to create a consumer-influenced shift in load from on-peak to off-peak usage, effectively adding capacity to the grid when demand is high. Smart rates will not directly reduce consumer demand for electricity, nor will they increase energy efficiency; instead, they will shift the demand to lower-cost, off-peak times.

What are smart rates?

These are "rate designs that require the type of data collection that smart meters provide, and that are expected to produce significant peak load reductions, reduced and shifted energy consumption, improved system reliability, improved power quality, and reduced emissions. These include Time Of Use, Peak Time Rebate, Critical Peak Pricing, and Real Time Pricing." (Lazar and Gonzales, 2015) Smart rates also include rates that reflect the value of utility control of customer-sited load.

Smart rates are designed to take advantage of the data provided by AMI technology to more accurately assign costs among consumers, based on where and when they use electricity. Smart rates reinforce long-standing principles of efficient rate design, in that they reflect the utility's cost to serve a particular customer at a particular time. Efficiently designed rates reflect marginal costs, recover system costs on a volumetric basis, and send appropriate price signals to consumers who may adjust use accordingly.[214]

Section 13 of Act 199 of 2014 required that DPS work with the Agency of Commerce & Community Development to investigate the competitiveness of Vermont's industrial or manufacturing businesses with regard to electricity costs. The DPS is currently exploring how best to incorporate into rate design proceedings the impact of electricity costs on business competitiveness, along with the identification of the costs of service incurred by businesses. The design and implementation of smart rates will take into account the results of that investigation, which will be available in January 2016.

Although smart rates have been discussed and tested for at least 30 years, a new urgency for them has been motivated by a strong perceived need to link wholesale and retail power markets in ways that will enable customers to understand and influence their own consumption, and to better understand the impact their consumption has on our planet. Smart rates are being deployed across the country: Baltimore Gas and Electric is moving all residential customers with AMI to a peak time rebate structure; and the vast majority of customers in California are expected to shift to a default time-of-use rate by 2018.

[214] James Bonbright, *Principles of Public Utility Rates* (Columbia U. Press, New York, 1961)

Smart rates are made possible by AMI because utilities need real-time data about customer usage to charge different rates, depending on the time of day electricity is being used. Utilities that have not yet deployed AMI should continue to evaluate the costs and benefits of transitioning. Recent developments offer new opportunities to implement smart retail rates: these include organized wholesale markets that produce transparent hourly market clearing prices, and consumer and regulatory interest in greater price-responsive demand.

Smart appliances that are coming on the market can be turned on to take advantage of low-priced electricity, then turned off when electricity is more expensive. For example, electric vehicles can be charged at night when prices are lower, and the temperature in a home with air conditioning can be slightly raised when electricity costs are high. Homeowners could use a variety of software applications or services provided by their utility to take advantage of smart rates automatically. Distribution utilities may act as managers of these smart appliances, working behind the scenes to lower peak-time use to save money for both customer and utility. Customers would be compensated for their voluntary participation in any utility or third-party-directed load management programs. Distribution utilities should coordinate their efforts with the energy efficiency utilities, so that incentives and rebates offered to customers through efficiency programs take into account the ability of new equipment and appliances to respond to utility load control signals.

Among the categories of smart rates are hourly pricing; daily pricing, including time-of-use, variable peak rate, critical peak pricing, and peak-day rebate; fixed time-of use pricing; and seasonal flat pricing. Other smart rates include vehicle charging rates, rates related to distributed generation, and rates that reflect the value of utility control of appliances or equipment. The specific type and design of smart rates for utilities in Vermont will depend on their particular AMI infrastructure, load shapes, administrative capabilities, and resource management goals.

Along with offering consumers the opportunity to save money by using electricity when rates are low, smart rates offer many benefits to the electric grid. By shifting consumption away from peak times, utilities will avoid wholesale capacity charges and lower Vermont's cost share of regional transmission projects. Smart rates can help to reduce capacity and energy charges in the long term, and to trim wholesale market prices in the short term.[215] Power supply savings, including both RNS and FCM savings, that result from peak shifting should be passed through to ratepayers.

There is some evidence that low-income consumers are less able to take advantage of smart rates because they have less flexibility in when they use electricity. In addition, some of the benefits that come from smart rates require investment in new or upgraded models of appliances, to which some low-income customers may not have access. Further, several studies have shown that low-income customers adjust

[215] Ahmad Faruqui, Sanem Sergici and Jennifer Palmer, *The Impact of Dynamic Pricing on Low Income Customers* (Institute for Electric Efficiency, The Edison Foundation, 2010), www.edisonfoundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf

their usage less in response to smart rates than do average customers.[216] Even so, low-income customers still benefited from smart rates because they tended to use electricity off-peak, and because overall system costs were lower. However, it is important to carefully consider the impact of specific smart rate plans on low-income customers. Utilities should take steps to ensure that low-income customers benefit from smart rates.

Recommendations

(1) *Beginning immediately, electric utilities should work in coordination with the DPS, EEUs, and PSB to create smart rate transition plans. Such plans should be incorporated into utilities' future integrated resource planning processes. Utilities should have a plan in place by 2017 to implement simple, fairly priced smart rates for each customer rate class, recognizing that utilities which have not deployed AMI capability may not be able to offer smart rates to all customers. By 2018, all Vermonters served by distribution utilities with AMI infrastructure should have access to smart rate options designed with AMI in mind.*

(2) *Utilities should make smart rates the standard rates for all customer classes by 2021, subject to the following exemptions:*

   a. *Customers without AMI or time-of-use meters are not expected to transition to smart rates. This means that utilities without AMI need not develop or implement smart rates for customers and classes using legacy meters.*

   b. *Utilities that use smart rates, including load control, to lower residential and small commercial customer costs associated with peak energy use by 10% or more by 2019 are exempt from this requirement. Through the development of their smart rate transition plans, utilities will work with the DPS to develop metrics to measure and verify this performance, which could include savings on peak energy, capacity, and regional network service, as well as credit for reducing infrastructure or other system costs.*

(3) *Customers should always retain the right to choose a flat rate, recognizing that they may pay a risk premium for guaranteed prices.*

(4) *Utilities should take intermediate steps to ensure that customers understand new and existing smart rate options during the coming transition period. Tools to use during the transition could include delivering shadow bills that show customers what their monthly bills would be under new rate plans. Utilities with an alternative regulation plan could consider offering bill guarantees for a limited period to customers who switch to smart rates, so that these customers would pay either their legacy rate or the new smart rate, whichever is less expensive.*

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[216] Ibid

(5) *Utilities and the DPS should identify and address any differential effect of smart rates on low-income Vermonters by prioritizing services such as provisioning and automation of smart appliances, lowering overall energy bills through efficiency and weatherization, and ensuring simplicity in smart rate design especially for residential customers.*

10.3.5 Conservation Voltage Regulation and Volt-VAR Control

Conservation voltage regulation (CVR) is an energy efficiency program applied to an electric utility's distribution system, involving measures and operating strategies designed to provide service at the lowest practicable voltage level in a cost-effective manner, while meeting all applicable voltage standards. Field studies have shown that, in general, a one percent reduction in the voltage delivered to customers results in a one percent reduction in energy consumption.

Utilities can control distribution-line voltage by changing settings on equipment at the substation serving the line, or on equipment connected along the line. Voltage falls gradually as current flows further from the substation. Utilities must keep substation voltage at a level sufficient to ensure that voltage at the end of the line is within industry standards. Traditional methods of voltage control require a margin above minimum voltage standards; but real-time data communications and remote control allow for margins to be smaller without affecting service to customers or damaging their equipment.

Historically, CVR was a substation bus-level strategy for implementation on traditional feeders where power flows in a single direction, from the source to the load only. To adjust the voltage, CVR typically utilized stand-alone substation voltage regulators or transformers with load tap changer (LTC) controls. While down-line feeder conditions were taken into account, CVR was used primarily for gross adjustments. In Vermont, experience has shown that many circuits are not appropriate for this type of CVR implementation. For example, traditional CVR may not be a good strategy for very long circuits when voltage regulation occurs only at the substation bus; and circuits with large commercial and industrial loads that provide their own voltage regulation. In addition, CVR may not be effective with circuits containing high concentrations of distributed generation (DG).

Increasing penetration of distributed generation, in particular solar, has resulted in problems with voltage regulation, which in turn is complicated by CVR implementation. Some Vermont utilities have had to remove CVR on circuits to assure proper operation during daylight hours. DG will reduce the amount of current at the line-drop compensation (LDC) controls of regulators or tap-changing transformers located in the substations. This current reduction then reduces the apparent voltage drop across the length of the feeder, and results in low voltages delivered to customers at the ends of feeders. In some cases, CVR can also result in system problems where reverse power flow occurs.

Delivering power within appropriate voltage limits so that customers' equipment operates properly, while providing power at an optimal power factor to minimize line losses, requires the consideration of a variety of factors throughout the distribution system. These factors include, but are not limited to, substation bus voltages; length of feeders; conductor size; the type, size and location of different loads;

and the type, size, and location of distributed energy resources (renewable energy generation and storage resources). Balancing these considerations will be increasingly complex — and increasingly important, assuming that more distributed energy resources will likely be added to the grid.

With the limitations of traditional CVR, simply lowering voltage by this means alone will likely not be an effective strategy. But with the development of computing platforms, advanced algorithms, and high-performing communications and locational sensor technology associated with AMI, it is increasingly possible to coordinate and manage the distribution system better at the feeder, substation, or utilization level. Volt/VAR control, as a strategy, provides such an opportunity.

Voltage regulation and volt-ampere-reactive (VAR) regulation are often referred to in the load management context together as *volt/VAR control* (VVC). Power systems require a combination of real power and reactive power. *Voltage optimization* refers to the management of voltages on a feeder with varying load conditions, whereby voltages must remain within ANSI standard limits. *VAR optimization* refers to supplying the right amount of reactive power at the right time (within a dynamic distribution system). *Real power* is supplied by a remote generator (watts), and *reactive power* can be supplied by a remote generator or a local supply (coil or capacitor).[217]

Future implementation of CVR should take advantage of utilities' maturing programs for advanced metering infrastructure, along with expanded implementation of supervisory control and data acquisition (SCADA). Among the strategies available with AMI and SCADA is the integrated distributed model-based volt/VAR control of distribution circuits. This is a control strategy in which distribution circuit information — including voltage, load, and power factor — is used to optimize circuit feeders. This can incorporate information of distribution circuit configurations from geographical information systems, detailed measurements from AMI and SCADA, and optimal power flow algorithms. This information can be used to integrate distributed resources (DR), including energy storage and load control, with traditional distribution voltage control devices such as regulators and capacitors.

The DPS anticipates that implementation of these strategies will have a significant learning curve, because of the technical challenges associated with the need for well-defined electric circuit models, defined control schemes, communication infrastructure, and monitoring requirements. In view of these challenges, the DPS believes that utilities should initially focus on having accurate GIS data and circuit models and an ability to access the requisite AMI, SCADA, and DR information to integrate into circuit models. Without highly reliable information, it is unlikely that VVC implementation or other optimization strategies would succeed.

[217] Understanding and controlling the VAR component of VVC is somewhat abstract. To explain it in simple terms: in any given distribution system, the voltage and current take the form of sine-waves within a power line and it is common for the voltage and current waveforms to not be perfectly synchronized due connected load characteristics. The asynchronous waveforms on an AC power line represent the VAR component of VVC. Correcting for the voltage and current asynchrony optimizes the system and saves energy.

The DPS recognizes that control technology and software is rapidly evolving, and expects that utilities will gain an understanding, and stay current with, these advancing control technologies. In addition the DPS recognizes there are customer-side VVC technologies to consider as well. Once these challenges are understood, the utilities should shift their focus to developing pilot programs that test the efficiency and cost-effectiveness of optimized circuit feeders. Given the potentially high cost in dollars and resources, and the integrated nature of smart grid technologies, it may be desirable to package VVC implementation with other smart grid opportunities — e.g., fault detection isolation and recovery (FDIR) and the optimization of DR.

Recommendations

(1) *Distribution utilities should initially focus on having accurate GIS data and circuit models and an ability to access the requisite AMI, SCADA, and DR information to integrate into circuit models. Utilities should expand SCADA implementation, as necessary, to allow remote control of voltage control devices, data acquisition, and future flexibility.*

(2) *Distribution utilities should describe and report on their progress with VVC in their integrated resource plans.*

(3) *The DPS should coordinate with the DUs to have a third party evaluate the impacts of VVC initiatives and identify the appropriate feeders for long-term VVC.*

(4) *The DPS should explore performance-based incentives for distribution utilities that implement VVC with measurable and verifiable benefits.*

10.4 Storage

Reducing and controlling load are two of the key tools for managing energy demand. The third tool, energy storage, is increasingly important as our reliance on intermittent resources increases. *Energy storage* covers the storage of thermal, electric, and electrochemical energy and encompasses a wide variety of technologies, from pumped hydroelectric and fuel cells to compressed air and batteries. Energy storage can serve a wide variety of purposes, from shaving electricity demand peaks and supporting grid voltage to providing backup power and "firming" the output of intermittent renewables.

Energy storage may seem like a silver bullet to address many of the needs of a managed grid with a high penetration of distributed, renewable energy, but it has historically been too expensive to deploy on any meaningful scale. But that tide is turning, much as it did for solar PV over the last decade, as the result of targeted commercialization efforts by the DOE, energy storage mandates at the state level, recognition of value by grid operators, and maturation of the market. A recent report[218] produced for the Australian Renewable Energy Agency predicts that battery prices will fall 40% to 60% by 2020 — which is good news, as the International Renewable Energy Agency is predicting[219] that the world will need to deploy 150 gigawatts (GW) of battery storage by 2030, along with 325 GW of pumped hydroelectric storage, in order to integrate the 800 GW of solar and 550 GW of wind whose deployment will be necessary in order to restrict global temperature rise to 2°C by the end of the century.

Vermont has not yet adopted energy storage mandates like California's[220] or Oregon's[221], nor has it implemented a targeted incentive program for storage similar to New York's[222] or Massachusetts's[223]. Even so, Vermont is leading the way on several electric and thermal energy storage fronts.

Residential Energy Storage

In 2015, Green Mountain Power announced that it would be the first utility to offer the new Tesla Powerwall to its customers, starting in early 2016. Tesla's announcement of the Powerwall, which comes initially in a modular 7 kWh "daily cycle" size, marked a seminal moment for the energy storage industry in terms of technology cost, scale, and demand, with units — priced at $250/kWh — sold out through 2016.

The Powerwall has the ability to more closely align customer loads with periods of lower electric demand, store solar electricity for use in the evenings, and provide some amount and duration of backup power during outages. Individual customers have the potential for cost savings from both the load and renewables-management features of storage, while the utility may have the opportunity to lower costs for all customers by aggregating and activating the load management features of multiple systems during periods of peak demand, such as hot summer days when cooling demand is high. In August 2015, GMP proposed to install two 10 kWh Powerwalls at Emerald Lake State Park in East Dorset, to take the park off the grid and provide for its electricity needs. The cost is estimated to be 20% less than that of rebuilding the existing distribution line.

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218 Carl Christiansen and Ben Murray, *Energy Storage Study* (for Australian Renewable Energy Agency, 2015), arena.gov.au/files/2015/07/AECOM-Energy-Storage-Study.pdf

219 International Renewable Energy Agency, *Renewables and Energy Storage* (2015), www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Electricity_Storage_2015.pdf

220 California Public Utilities Commission, *Energy Storage,* www.cpuc.ca.gov/PUC/energy/storage.htm

221 olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

222 "NYSERDA Announces MW Block Incentive Program for Commercial and Industrial Grid-Connected Solar Energy Systems," www.nixonpeabody.com/NYSERDA_announces_performance_based_incentives

223 Mass. Office of Energy and Environmental Affairs, "Baker-Polito Administration Announces $10 Million Energy Storage Initiative," www.mass.gov/eea/pr-2015/10-million-energy-storage-initiative-announced.html

Commercial and Utility-Scale Energy Storage

Not only will Vermont customers be among the first to have access to the Powerwall, but a Vermont company — Dynapower of South Burlington — was announced as the supplier of inverters for the Powerwall's big brother, the 100 kWh Powerpack, designed for commercial and utility customers. At an estimated capital cost of $250 per kilowatt-hour, the Powerpack is priced well below what analysts predicted would be necessary for batteries to be cost-competitive with new peaking plants for electricity[224]. It even has the potential to supplant use of existing power plants.

While the potential of the Powerpack is impressive, it is still on the horizon, and Vermont has other near-term storage accomplishments from which it can glean real insights. In 2013, the DPS partnered with the DOE's Office of Electricity (DOE-OE) and the Clean Energy States Alliance (CESA) to encourage a utility-scale energy storage demonstration project. The DPS's Clean Energy Development Fund issued a $50,000 solicitation, and the DOE-OE agreed to contribute $235,000 in funding to the selected project.

The Stafford Hill energy storage project was chosen to receive funding, and became operational in 2015. This 4 MW, 3.4 MWh electric energy storage system was installed in conjunction with a 2 MW solar photovoltaic project in Rutland by Green Mountain Power, with controls supplied by Dynapower. The system's primary purpose is to facilitate and maximize renewable energy integration with the electric distribution grid. Secondary applications are also being explored, including providing backup power to the local emergency shelter (and potentially an entire distribution circuit), improving power quality, promoting grid efficiency, offering ancillary services such as ramping into the regional wholesale market, and serving as an educational tool for students. Sandia National Laboratories is providing data analysis and other technical assistance to the project, and GMP is working with VEIC to share best practices and lessons learned with regulators, other Vermont utilities, and stakeholders at the state, regional, and national levels.

GMP is also in the process of assessing the value of thermal storage at several test locations in Rutland. Thermal storage — in this case ice storage — is a way to manage the electric demands of cooling commercial buildings. Essentially, ice storage systems make ice when electricity supplies are cheap and abundant (at night), and use it to efficiently cool buildings during the day, when demand and prices are high.

The Future of Energy Storage

By the time the next CEP is adopted, Vermont will have learned a great deal about the deployment of energy storage at the residential, commercial, and utility scale. At the rate that costs are decreasing —

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[224] Judy Chang, et al, *The Value of Distributed Eletricity Storage in Texas* (for Oncor Electric Delivery Company, 2014), www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf

much faster than analysts predicted[225] — energy storage is set to become a disruptive force in the energy marketplace. In fact, the Rocky Mountain Institute (RMI) recently estimated[226] that installing solar plus storage would become economic for millions of customers in the U.S. by 2030. After Tesla announced its battery prices, RMI revised that predicted date to a full seven years earlier, to 2022.

The adoption of electric vehicles will also play a major role in both the economics of storage and the management of the grid. As battery and vehicle manufacturing more closely coordinate, and align their products with the grid's operation, products will emerge for consumers — such as vehicles with algorithms that integrate energy price signals, solar photovoltaic production, and backup storage functionality — that also have some value in the aggregate for reducing peak loads and providing other grid services.

The fact that energy storage blurs line between load and supply, and offers other values to consumers, utilities, and grid operators, poses challenges that regulators, utilities, and industry will need to address sooner rather than later. These include the lack of industry standards, regulatory barriers to aggregation of behind-the-meter systems, protocols for charging and discharging of storage units (especially vehicle batteries) to prevent stress on the grid, and interconnection rules that properly account for the many use cases of storage. As the industry matures, and states including Vermont learn from the pilot projects we are undertaking, solutions to these growing pains will emerge — but it's clearly time to get started.

Recommendations

(1) Study the performance of the Stafford Hill project after a period of operation to understand costs, benefits, and implications for grid-scale storage in Vermont.

(2) Explore opportunities for further collaboration with the DOE and Sandia National Laboratories with a focus on developing specific projects in Vermont.

(3) Work with GMP to assess the uptake, performance, and grid benefits of residential and commercial Tesla Powerwall deployments.

(4) Review the regulatory requirements for electric energy storage and capitalize on existing regulatory reform opportunities — such as the Rule 5.500 interconnection procedures — to address storage.

(5) Work with VELCO and the distribution utilities to assess the benefits of utilizing grid-scale storage.

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225 Bjorn Nykvist and Mans Nilsson, *Rapidly Falling Costs of Battery Packs for Electric Vehicles* (Nature Climate Change, 2015), www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html

226 Rocky Mountain Institute, *The Economics of Load Defection*, www.rmi.org/electricity_load_defection

11 Meeting Vermont's Electric Demand

Electric generation meets Vermonters' electricity needs by converting a variety of resources — renewable, fossil, and nuclear — into electricity and reliably delivering that power to our homes and businesses. The ongoing rapid shift toward an integrated grid, with both central and distributed generation, and toward both dispatchable and variable generation, matching an increasingly controllable load, opens new avenues for utilities to build cost-effective portfolios when these elements are viewed with other utility costs as an integrated whole.

This chapter first describes the state's future electricity supply, in the context of Act 56's new requirements for electric portfolios. Generating electricity within Vermont provides benefits, and also creates some local costs; the chapter describes the state's approach to planning for and siting physical generation and grid infrastructure, along with its strategies to promote responsible in-state renewable electricity generation. The regional transmission network delivers our power, and the markets and policies implemented there have a direct impact on how Vermont procures and pays for electric supply.

Disruptions to the in-state and regional electric grids, or to energy resources both local and far-flung, can generate real risks to economic and human health, so we must also plan for energy assurance. Recommendations are provided to facilitate acquisition of appropriate resources to set Vermont on a path to attain the goal of achieving 90% total renewable energy by 2050. We discuss specific policy tools that will help us achieve our goal.

The chapter concludes by building on Vermont's history of integrated resource planning, to propose the need for comprehensive analysis of integrated planning in a context of distributed energy resources. The combination of distributed generation, energy storage (including storage in the form of electric vehicle batteries), efficiency, and controllable electric loads has the potential to create substantial changes in how infrastructure and power supply decisions are made, along with their regulatory context (as discussed in chapter 9).

11.1 Future Electric Supply from a Portfolio Perspective

Act 56 of 2015 established a multi-tiered renewable energy standard for Vermont's electric utilities. This set of obligations on each utility will have profound effects on how utilities make choices for their power supply portfolios. Increases in electric demand resulting from increased electricity use for both space and water heating (efficient cold-climate heat pumps) and transportation (electric vehicles) will also require corresponding increases in power supply, and changes in the shape and controllability of electric loads, especially as 2050 approaches.

Vermont utilities can continue to develop renewable sources of power for their customers, through direct deployment of and contracts with in-state resources, contracts with resources out of state, and strategic use of system power. The principles of least-cost planning require that utilities use all the tools at their disposal, including market forces, to identify and procure sources of energy. Vermont must ensure that the electric sector plays its part to reduce the state's overall GHG emissions to sustainable levels, and to ensure affordable, reliable, secure electric supply into the future. As the regional and in-state supply grows more renewable, Vermont will be well-positioned to maintain a clean, regionally competitive power supply.

11.1.1 Impact of Act 56 on Power Supply

Act 56 established a Renewable Energy Standard (RES) with two power-supply renewable-energy obligations for electric utilities[227]:

- Tier 1 is a total renewable energy requirement, requiring that renewable energy totals 55% of retail electric sales in 2017, climbing 4% every three years to 75% in 2032.

- Tier 2 is a carve-out of Tier 1 that requires new distributed generators (5 MW or less) connected to Vermont's electric grid (or otherwise supporting our grid) to total 1% of retail electric sales in 2017, rising 0.6% each year to 10% in 2032.

The RES also includes a Tier 3 requirement that electric utilities assist their customers in reducing fossil fuel use by an amount equivalent to 2% of retail electric sales in 2017, rising to 12% by 2032. This invites electric utilities to participate, with partners where possible, in markets for fuel, appliances, and vehicles that have traditionally been unregulated. This embraces a broad sense of the energy services that can be provided by electric utilities at least cost.

Compliance with the RES will be demonstrated through ownership of renewable energy attributes corresponding to energy from eligible generators. Such attributes might be acquired with the energy, or separately. Where possible, the New England attribute tracking system, the NEPOOL Generator Information System (NEPOOL GIS), will be used, although some imports (e.g., from Hydro-Quebec) may need to be accounted for separately until the inter-regional NEPOOL GIS processes can be better defined, while ensuring no double-counting of attributes.

Because renewable energy certificates (RECs) may be separated from energy, utilities need not procure energy directly from the required amount of renewable energy resources. For example, a hydroelectric plant may sell its power into the New England wholesale energy markets without a long-term contract, and may separately choose to sell its RECs to a Vermont utility. That utility in turn may purchase generic market power or energy from any other source to meet its customers' moment-to-moment energy needs, as long as it owns the required number of RECs at the time of compliance. This flexibility means that Vermont utilities are not required to procure energy directly from renewable generators in an amount corresponding to the RES requirements. That said, Vermont utilities already procure approximately 45%

[227] This is a summary of the requirements; various other provisions add additional flexibility.

of retail electric sales from renewable sources and retain the RECs, so some level of continued correspondence between power supply and RECs is expected.

Because of the financial benefits of long-term contracts or ownership enabled by Vermont's regulatory structure, most eligible Tier 2 generators are likely to be owned by Vermont utilities, under long-term contract to them (including through the Standard Offer program), or net metered. As such, there is expected to be a much greater correspondence between energy supply and REC ownership for Tier 2 than Tier 1, accounting for sales of RECs between Vermont utilities. Tier 2 will make up approximately half of the increase in renewable energy for Tier 1 (10% is half of 75%-55%=20%). Net metering will reduce utility sales, but can also be thought of as a kind of power supply resource.

Tier 3 of the RES may have some indirect impacts on electric power supply requirements. One way is that Tier 2-eligible RECs may also be used for Tier 3 compliance. In addition, changes in electric demand resulting from strategic electrification (such as the adoption of cold-climate heat pumps or electric vehicles) may change both the amount and the load shape of required electric power. Load shapes will change on a daily basis (e.g., due to overnight EV charging) or on a seasonal basis (e.g., heat pumps driving increased winter electric needs). The extent of these effects depends on how utilities meet their Tier 3 obligations. DPS modeling conducted during the legislative process for Act 56 indicated an 8% to 10% impact on sales by 2032. Rate impacts from this increase in sales could be beneficial if peak demands are managed well, resulting in a flatter overall load shape.

11.1.2 Implementing the Renewable Energy Standard

This CEP will be in force for the first six years of the RES, with the first utility obligations in 2017. It is likely that implementation of the RES by 2021 will have evolved significantly from its initial conception. However, some fundamental principles regarding intention and approach will guide implementation through the coming years.

Tiers 1 and 2 are fundamentally very similar to the renewable portfolio standards (RPS) adopted by other New England states. Our RES rule for these tiers is therefore likely to be very similar to those in our neighboring states. Renewable energy credits are tracked in the regional NEPOOL GIS. Vermont's use of this system will ensure that there is no double counting of RECs between our utilities and those in other states. Our RES relies on, and provides credit for, imported resources (particularly from Hydro-Quebec), which at present are not reflected perfectly in the NEPOOL GIS. Addressing this will require either changes in that system (expected in the medium term) or outside accounting of the renewability of these resources (for the time being). Net metering RECs assigned to their host utilities cannot be transferred, so utility billing systems combined with tracking of REC assignment should be sufficient to verify utility RES claims. Utilities can aggregate RECs from net metering systems and track them in the NEPOOL GIS to minimize any double-counting risk.

Utility RES requirements under Tiers 1 and 2 are equivalent to a requirement for DG resources ramping from 1% in 2017 to 10% in 2032, and to a separate, additional requirement for any renewable resource ramping from 54% to 65%. Utilities will be more assured of meeting the requirement, better insulated against policy changes in other states, and better able to make clear renewable energy claims if they acquire energy from renewable sources corresponding to these amounts, along with acquiring the RECs. The Act 56 structure acknowledges that renewable resources that came online before July 1, 2015, or are larger than 5 MW, may be treated as premium resources by other states. Such resources provide a backstop for Tier 1 compliance, but utilities are expected to maximize ratepayer value while meeting the RES.

When developing Tier 2 compliance portfolios, utilities should directly account for the in-state and grid-supporting nature of these resources. When choosing such resources, then, utilities should strive to deliver maximum ratepayer value, combining load shape (and related capacity value), location, and price to an optimal mix. Utilities must also plan for some level of uncertainty regarding which generators will provide Tier 2 RECs, given the role of independent power production through the Standard Offer and net metering. The integrated resource planning (IRP) process described later in this chapter should be a primary tool that utilities use to examine these portfolio and infrastructure choices.

Tier 3 energy transformation projects have the potential to change utility electric sales, and thus their supply portfolio needs. For example, a utility may support the transition of a building's heating system from a fuel oil boiler to a cold-climate heat pump. In that case, the building's electricity demand will increase, thereby increasing the need for electric supply coincident with the heat pump's use.

More fundamentally, however, energy transformation engagement by distribution utilities opens the door to changes in the utility's role. Underlying state policy guidance to pursue least-cost energy services, including economic and environmental costs, provides a baseline as utilities develop their compliance plans. By definition, energy transformation projects reduce customers' fossil fuel energy costs, along with the environmental costs associated with that use. The shared nature of the grid infrastructure also opens the door for shared electric system benefits from Tier 3 projects.

As utilities develop energy transformation portfolios, they should consider these guiding principles:

- Strive to maximize net ratepayer value from their project portfolio, including participant and non-participant value.
- Provide a diverse range of options to increase the likelihood that any customer can participate; in particular, ensure that low-income customers benefit through participation and not only through shared system savings.
- Work to lower rates by maximizing Vermont's load factor — the ratio of average load to peak load — through careful management of any peak load impacts from Tier 3 projects.
- While consistency across multiple utility territories is important, so is trying new program offerings.

- Carefully consider the performance of programs, working to change them quickly to match market conditions.

- Recognize the resources beyond incentive payments that distribution utilities can provide to move markets and reduce fossil fuel use — including access to capital, ability to coordinate bulk purchase or community projects, continuity of service to rental properties, and use of the electric bill for marketing and repayment.

- Plan for the long term, including planning for increased and continuing Tier 3 obligations, to develop market transformation programs and strive for comprehensive energy service to each participating customer.

- Build on existing programmatic infrastructure and expertise developed by energy efficiency utilities, weatherization programs, and other energy service companies.

- Consider community-scale partnerships that can serve many customers in a single coordinated set of actions, as well as programs serving individual customers.

Looking beyond initial implementation, the three tiers of the Renewable Energy Standard combined are expected to meet only one quarter of the state's GHG reduction goals. Other policies should be designed with the RES in mind, and the RES should be flexibly implemented in order to work well with other policies or programs that achieve further renewable cost-effective adoption of efficiency, conservation, and renewables across the entire energy portfolio.

Recommendations

(2) Where cost-effective, utilities should consider acquiring energy and RECs from renewable resources in the amounts of Tier 1 and 2 RES requirements, rather than only RECs.

(3) When developing Tier 2 and 3 compliance portfolios, utilities should directly account for the grid-supporting nature of these resources to deliver maximum ratepayer value.

(4) Utilities should consider the guidance above when developing energy transformation portfolios.

(5) Utilities should use competitive procurement processes, such as requests for proposals, to identify promising and low-cost sources of energy and RECs, while recognizing that the costs and benefits of a generator may not be expressed solely in its cost per MWh.

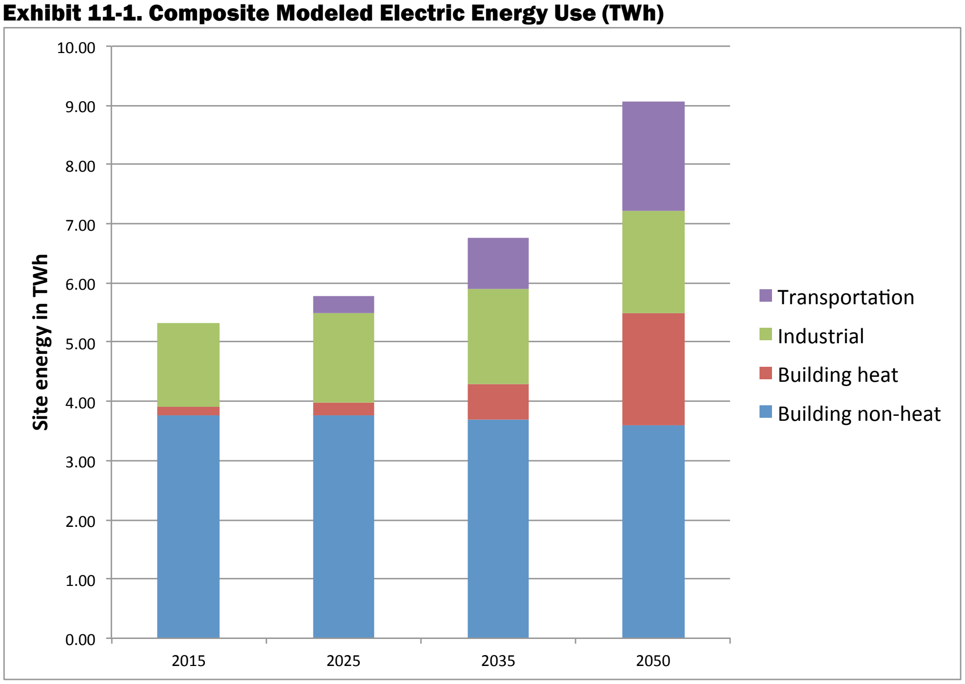
11.1.3 Insights from the Total Energy Study

The 2014 Total Energy Study examined several future scenarios under which the state meets its 2050 GHG and renewable energy goals. These scenarios differ in how much electric energy is required, but collectively they provide a range of possible 2050 electric energy demand that can be used to understand portfolio and land use implications.

The low end of the range (8 TWh/year) corresponds to a case with extensive use of liquid biofuels; the high end (approaching 10 TWh/year) to a case with limited use of such fuels. All of these cases incorporate extensive and aggressive electric energy efficiency. For comparison, current annual electric use is approximately 5.5 TWh; after accounting for losses generation, of approximately 6 TWh is required. In each case, the electric supply must be virtually 100% renewable, because some other end uses have greater need than does electric generation to retain non-renewable fuels. This increasing electric use corresponds to a need for increases in supply, particularly in renewable supply, in Vermont's portfolio.

As an example only, one composite scenario at the higher end of the range of electric demand growth, shown in Exhibit 11-1, illustrates how different energy-demand drivers contribute to this growth in energy demand. In Total Energy Study modeling, Vermont's population grows 3%, its GDP more than doubles, and the square footage of commercial buildings grows 13%. Nonetheless, this scenario shows electric demand for purposes other than heating, transportation, and industrial uses staying level, indicating both the extent of embedded energy efficiency and the changes driven by electrification of heat and transportation.

Exhibit 11-1. Composite Modeled Electric Energy Use (TWh)



To inform consideration of the cost and benefits of different electric portfolios, Exhibit 11-2 summarizes three electric portfolios, each of which generates approximately 9 TWh per year. Each of these scenarios maximizes the amount of generation likely to be available from anaerobic digestion (methane[228]), woody biomass electric generation, and in-state run-of-river small hydroelectric facilities. As such, they vary in their ratios of solar, wind, and large hydroelectric. Vermont's actual portfolio will not be identical to any one of these, and will be developed taking the costs and benefits of each energy source into account.

It is reasonable to assume that solar PV serving Vermont will be overwhelmingly located here. To date, Vermont utilities have acquired about 55% of their wind power from facilities in Vermont, the remainder from out of state. Large hydro would either be imported (e.g., from Maine, New York, or Canada) or acquired from existing Connecticut River and Deerfield River hydroelectric facilities (which have lower capacity factors than assumed here, so would require more MW of capacity). Today, Vermont utilities get about half of their renewable energy from in-state sources, and half from out of state (prior to REC sales and purchases). These three scenarios would maintain at least half their generation in Vermont if each technology maintained its current in-state/out-of-state mix. Scenario A is 65% in-state; B is 58% in-state; C is 53%.

Exhibit 11-2. Three Scenarios for 100% Renewable Electricity in 2050

Fuel	Scenarios: MW of Generation Capacity		
	A	B	C
Solar	2250	2250	1500
Wind	750	400	750
Methane	15	15	15
Biomass	100	100	100
Sm. Hydro	175	175	175
Lg. Hydro	250	370	370

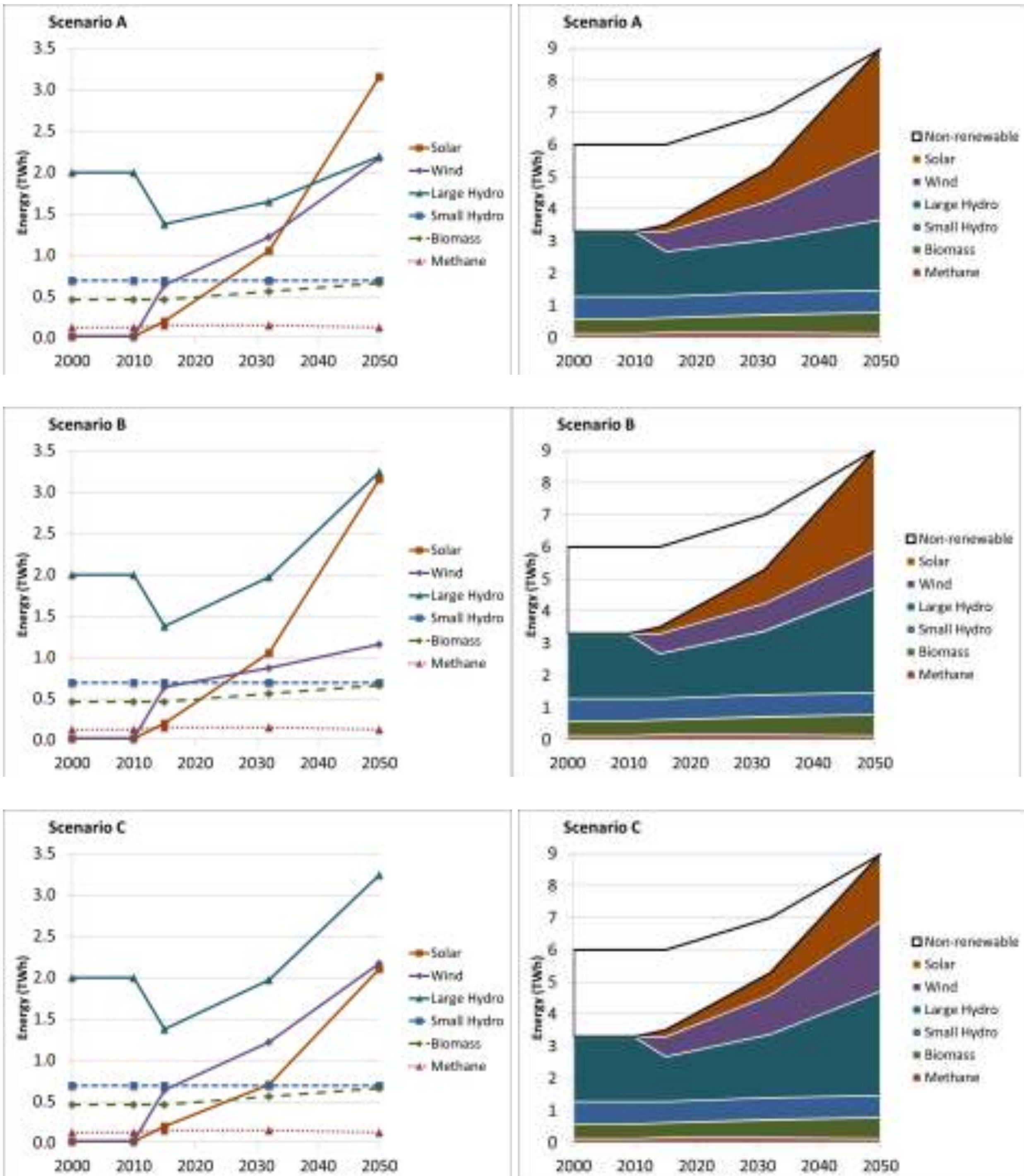
Exhibit 11-3 shows the approximate energy derived from each of these resources under each scenario. In this exhibit, 2000, 2010, and 2015 data are based on actual utility portfolios[229]. The three scenarios for 2032 achieve the RES requirements of 75% renewable and 10% new distributed generation, and the 2050 data correspond to the scenarios shown in Exhibit 11-2. It is critical to note that this figure represents portfolios for the years 2000 to 2015 before REC sales and purchases, and as such does not represent the power mix that has served Vermont customers. Its intention is simply to explore a range of possible portfolios and their land use impacts.

[228] These scenarios assume some decay in landfill methane production, compensated for by increases in anaerobic digesters.

[229] The methane line includes landfill gas, which is expected to decay significantly by 2050 due to the diversion of organics under Act 148.

Exhibit 11-3. Three Scenario Trajectories to 9 TWh of Renewable Electricity in 2050.

Each scenario is shown with lines for each resource (left panel) and stacked areas totaling the full portfolio (right panel). Exhibit 11-2 contains the MW of capacity assumed in these scenarios. Each generates 75% renewable portfolios in 2032, assuming 7 TWh of energy needs, and 100% renewable in 2050 assuming 9 TWh. 2000, 2010, and 2015 are based on existing utility portfolios (before REC sales or purchases), including the transition to the new Hydro-Quebec contract.



These three scenarios have different land use impacts. The following summary of possible impacts is approximate, and uses current estimates and rules of thumb. It is in no way intended to describe a prediction of the actual impacts from these scenarios, or to suggest that any of these scenarios is the exact future electric portfolio for Vermont utilities.

Assuming that all the solar PV serving Vermont load is located here, all these scenarios suggest significant increases from the current level of deployed solar. To date, there are approximately 120 MW of solar PV deployed (of which about 30 MW are residential-scale systems under 15 kW), and more than an additional 80 MW in some stage of the formal permitting process. Scenario C involves 1,500 MW, assuming an average 16% capacity factor. If approximately ¼ of residential buildings have roofs suitable for solar PV and these roofs are all used, then between 300 and 500 MW of solar PV could likely be deployed on residential roofs. If 350 MW were deployed on residential roofs, the 1,150 remaining MW would require about 8,000 acres (assuming seven acres per MW). To achieve 2,250 MW total in scenarios A and B, the 1,900 MW not on residential roofs would require about 13,000 acres. Disturbed lands, parking lots, and commercial rooftops would be possible sites for the non-residential generators. Rooftop deployment is more expensive than ground-mounted deployment, so the balance would have ratepayer cost implications as well as environmental and land use implications.

Under a grant from the DPS, a team of regional planning commissions has used geographic information systems to estimate the number of acres in the state that are good for solar (e.g., reasonably flat), and those that are not: FEMA floodways, river corridors, federal wilderness areas, rare and irreplaceable natural areas (RINAs), vernal pools, class 1, 2, and 3 wetlands, deer wintering areas, special flood hazard areas, conserved lands, hydric soils, habitat blocks of more than 2,000 acres, or local, prime, or statewide-classified agricultural soils. There are more than 340,000 acres of such lands in Vermont. Many of these are likely not suitable due to factors not accounted for, such as current uses, aesthetic impacts, or other elements. But it is also likely that many excellent sites for solar PV are not counted in this total, including sites on disturbed land and in the built environment. (For example, there are several thousand acres of commercial buildings and associated parking lots in Vermont.) Regardless, this data supports a conclusion that the estimated requirements for land area — even for the higher solar deployment in scenarios A and B — are very small compared with the statewide availability of suitable land.

If one assumes that 55% of the wind energy serving Vermont is located here, which is the current ratio, scenarios A and C would require approximately 410 MW of total capacity; scenario B would require approximately 220 MW (all assuming a 33% capacity factor). Currently deployed are 52 large wind generators, totaling 119 MW of capacity. This implies an average of 2.3 MW per turbine, but the three more recently constructed facilities average 2.75 MW per turbine. Scenario B would imply the equivalent of 36 additional 2.75 MW turbines; scenarios A and C imply an additional 106 such turbines. If all additional wind energy (beyond current utility ownership or contracts) were located in Vermont, rather than 55% of it, scenario B would imply 67 additional turbines; scenarios A and C would imply 194 additional turbines. Improvements in wind technology to increase capacity factors, or the use of higher-capacity turbines, could reduce the number of turbines needed to generate the assumed amount of energy.

Large hydroelectric generation under these three scenarios would either increase about 60% from current levels, or increase by a factor of 2.4. Scenario A would imply contracting for the equivalent of the nighttime hours on the Highgate interconnection with the Quebec electric system that Vermont utilities don't contract for now, plus another 20 MW of large hydro from some source. Scenarios B and C imply the equivalent of round-the-clock over the Highgate intertie and NYPA and an additional 140 MW, for a total energy of approximately 2.4 times what Vermont utilities currently purchase from such generation. The load shape and dispatachability of this large hydro resource will impact how it is able to work with variable resources.

With high levels of variable generation from wind and solar PV, all these scenarios demand continued and substantial change in the operation and management of the electric grid over the coming decades. Concurrent deployment of electric vehicles and other electric energy storage, along with other kinds of controllable loads and supply, will increase operational flexibility. Vermont's electric system operates as part of a region — which may have a different overall electric mix, including imports from outside the region, offshore wind, and other renewable and low-carbon electric supply. Grid operations and the regional context are discussed later in this chapter.

11.2 New Electric Generation in Vermont

Electric generation in Vermont can be a boon to the state's economy. However, not every generation technology, scale, and location may be appropriate to meet Vermont's needs. Larger projects yield greater generation and may be able to take advantage of economies of scale, but can have greater negative impacts; smaller projects have less individual impact, both positive and negative. Although the scale of smaller projects may be more readily accepted by Vermonters, it is important to ensure that the projects (which are likely to produce relatively modest contributions to Vermont's energy supply) truly reduce, rather than just distribute, environmental impacts. The increased assessment of cumulative impacts associated with smaller projects will be critical as Vermont continues down the path of distributed generation.

Building and operating electricity generation facilities requires significant investment that generates substantial direct, indirect, and induced economic benefit. A ripple effect of direct benefits results — including jobs, potential land-lease payments and increased tax revenues, indirect benefits from businesses that support the facility, and induced benefits from additional spending on goods and services (e.g., restaurants, retail establishments, and child-care providers) in the surrounding area.

Direct jobs created include engineering, legal services, manufacturing, construction, and operation and maintenance associated with electric generators. Jobs related to wind and solar projects are concentrated during the construction phase; these tend to be short-term and may employ some out-of-state workers.

Apart from jobs associated with specific projects, Vermont is home to a number of energy companies that employ Vermonters and export expertise and products.

Development of local renewable technologies such as biomass, wind, solar, and hydro will contribute to meeting the goals set by the Legislature and in the CEP, and will be responsive to the wishes of Vermonters as expressed during the broad public engagement processes held for revising the CEP. These technologies can be deployed in either a centralized or a distributed manner, depending on the appropriate scale of the resource and the economics of deployment.

Renewable generation technologies deployed on a small scale are currently more expensive than other sources of electricity. Even so, these smaller-scale renewable projects offer great potential, given the need for zero- and low-emission energy supply; for long-term affordability and price stability, as helped by the low-cost or no-cost fuels required to generate most forms of renewable electricity; for energy security and stability; and for a diverse resource mix, along with the expressed preferences of Vermonters for greater use of renewable resources, especially distributed and community-scale resources. Fostering small-scale and distributed renewable energy is an objective of the CEP. As the number of small-scale generators in the state grows, the DPS and electric utilities will continue to evaluate how to integrate these generators into the electric system in the most cost-effective and reliable ways. Proactive grid design and planning can address integration concerns before they serve to limit generation interconnection, although cost allocation for pro-active grid upgrades remains an open question.

Small renewable electric projects have a number of incentive mechanisms already built into the Vermont policy framework. Most notable is Tier 2 of the Renewable Energy Standard, which requires deployment of distributed renewables that are connected to Vermont's distribution grid, or that are part of an approved plan to avoid transmission costs. The Standard Offer program provides one programmatic mechanism to ensure that all utilities get power from in-state distributed-generation (DG) resources using a diversity of fuels and technologies. Net metering, the Vermont Small Scale Renewable Energy Program, the Clean Energy Development Fund, Nuclear Electric Insurance Limited (NEIL) program funds, green pricing programs, and tax incentives have all been important in encouraging small-scale renewable energy projects.

These programs have contributed to the maturation of these technologies, helped to foster the renewable energy industry in Vermont, and generated public awareness and acceptance of these technologies. The distributed projects that these programs have facilitated account for 2.5% of Vermont's total electric supply — and that number is expected to rise to 12% or more by 2032 under the RES. Specific tools to further facilitate renewable energy supply in both centralized and distributed applications are further discussed in this chapter.

Construction of new large-capacity generators such as combined-cycle natural gas plants, nuclear generators, and coal generators creates significant regulatory and other risks, due in part to the large capital expenses necessary to begin construction, the environmental impacts of large-scale construction, and the likely need for significant upgrades to transmission facilities to move the power efficiently.

Large-capacity combined-cycle gas plants have been the favored technology for most of the new generation built recently in New England — in fact, approximately 44% of New England's electric generation capacity uses natural gas, and this fraction is expected to rise. A large natural gas plant built in Vermont would compete with similar plants in New England, but would have no apparent long-term competitive advantage by being built here; siting choices would also be limited by the gas transmission infrastructure. Meeting Vermont's energy goals does not require such a plant.

11.2.1 Land Use and In-State Energy Resources

Renewable energy resources developed across Vermont to serve local energy demand will have some degree of impact on the landscape. The tradeoffs inherent in choosing to place a solar array, wind turbine, hydro dam, or other renewable generator on an open field, ridgetop, or river will alter that piece of the landscape for some period of time, and may preclude many other uses of that parcel. These tradeoffs are discussed in Chapter 5, as well as in the technology-specific sections of Chapter 13. Maximizing opportunities to use the built environment for co-location of renewables — on rooftops, parking lots, brownfields, grayfields, landfills, and so on — will ease some, but not all, of the pressure on the state's greenfields.

Citizens, towns, renewable developers, the environmental community, and state leaders are clearly feeling the strain of a burgeoning in-state energy resource buildout, especially with the volume of projects that entered the pipeline in anticipation of the expiration of key federal incentives in 2016. (These incentives have been extended with a ramp down over five years.) The buildout of distributed energy across the state means that people are experiencing the paradigm shift of coming face-to-face with our energy sources. Regions, towns, and individuals are struggling to find resources they can devote to understanding and participating in the energy permitting process, and many are starting to rethink the energy goals in their land use plans.

These growing pains are not unlike those that came with other substantial changes to Vermont's landscape, such as the advent of the state highway system and the proliferation of residential development that spurred the creation of Act 250. But unlike Act 250, the regulatory pathway for most of the significant non-energy development in the state, Section 248 — the part of Vermont Law (Title 30) that governs the siting of electric generation projects — was not developed in response to a proliferation of energy projects. Rather, it predates the type and scale of distributed, renewable energy development we're seeing now, and has been continuously modified and adjusted as state policy has changed to both accommodate and manage the buildout of these resources. The resulting suite of policies, processes, orders, rules, and precedent, and their attendant exceptions and caveats, does its best to capture the intent of policymakers and best practices gleaned through experience; but it does not offer a great deal of clarity and transparency for those without significant time to invest in parsing out the information.

In recognition of these issues, the Legislature and Administration have made — and continue to make — various attempts to reform the planning and siting processes for electric generation to reflect today's energy needs and generation resources.

Energy Generation Siting Policy Commission

On October 2, 2012, Governor Shumlin created the Energy Generation Siting Policy Commission (Siting Commission) through Executive Order No. 10-12. The Siting Commission's charge was to survey best practices for siting approval of electric generation projects (all facilities except for net- and group-net metered facilities) and for public participation and representation in the siting process, then to report its findings to the governor and the Legislature.

In April 2013, the Siting Commission released a report[230] containing its comprehensive package of 28 recommendations. These encompassed five broad themes:

- Increase emphasis on planning at state, regional, and municipal levels, such that siting decisions will be consistent with Regional Planning Commission plans.
- Adopt a simplified tiered approach to siting.
- Increase opportunities for public participation.
- Implement procedural changes to increase transparency, efficiency, and predictability in the siting process.
- Update environmental, health, and other protection guidelines (on a technology basis, where necessary).

Exhibit 11-4 lists all the recommendations, along with information on whether the recommendation requires statutory or rule change or has funding implications.

[230] Energy Generation Siting Policy Commission, *Siting Electric Generation in Vermont* (2013), sitingcommission.vermont.gov/publications

Exhibit 11-4. Matrix of Energy Generation Siting Policy Commission Recommendations

SITING COMMISSION RECOMMENDATIONS MATRIX

Recommendation Theme	Recommendation	Legislative Change	Rulemaking	Funding implications	Begin Implementation Now	Page(s) from SC Final
Planning	1. State Planning and Scenario Modeling			X	X (underway)	7, 8, 45
	2. RPC Planning (a), RPC Formal Party Status (b)	X (b)			X (a; underway)	7, 8, 48
	3. RPC Planning Costs (initial and ongoing)			X	X	7, 8, 48
	4. Municipal plans substantial consideration	X				7, 8, 47
Simplify Tiers	5. Simplified Tiers	X				7, 9, 48, 51
	6. Incentives within tiers	X				7, 9, 50
Public Participation	7. Establish a trigger point		X			7, 9, 50
	8. Earlier public notification	X				7, 9, 50
	9. Increase public engagement requirements	X				7, 9, 51
	10. RPC funding support during application period			X		7, 9, 52
Transparency, Efficiency, and Predictability	11. Hire Case Manager in PSB			X	X	79, 53
	12. Electronic Case Management/Online Docketing			X	X (underway)	7, 9, 54
	13. Develop checklists for each tier				X	7, 10, 54
	14. Concurrent timing of ANR permit filing and CPG		X			7, 10, 54
	15. PSB timelines for early stages of docket	X	X			7, 10, 54
	16. ANR response in keeping with performance standards				Underway	7, 10, 54, 55
	17. Overall CPG performance standards	X	X			7, 10, 55
	18. Rebuttable presumption for ANR permits	X	X			8, 10, 56
	19. Improve PSB website to create 'one-stop shop' for siting			X	X	7, 10, 56
	20. Update PSD website to provide pre-application information				X	7, 10, 57
Environmental, Health, and Other Protection	21. Update enviro, health and other standards and guidelines				X (underway)	8, 10, 58
	22. Modify Section 248 to give substantial consideration to Act 250 criteria	X				8, 11, 58
	23. Ag Agency become statutory party	X				
	24. DOH review and guidelines on health impacts				X	8, 11, 59
	25. ANR and PSD guidelines and tools for cumulative impact				X	8, 11, 59
	26. All parties agree on 3rd party monitoring experts and assign agency responsibility for oversight	X		X	X	7, 11, 59
Cross-Cutting	27. PSB 'pay attention' to list				X (underway)	11, 58
	28. Consider and assign funding sources	X			X (underway)	11, 60

Planning

Simplified Tiers

Technical Changes to Existing Statutory Language

While the Legislature has yet to adopt a comprehensive suite of recommendations, state agencies have made progress in discrete areas where possible. These include:

- *Electronic Case Management/Online Docketing System — Recommendation #12 (underway)*
  - The DPS and the PSB are in the process of implementing an integrated electronic filing web portal, case management, and document management system (PURE DOCS and ePSB), which will be searchable and will provide public access to all documents designated as public by either agency. The first version of the system is expected to become available in early 2016.
- *Comprehensive Planning — Recommendations #1 and #2* (underway)
  - Total Energy Study: Following the publication of the 2011 CEP, the Legislature asked the DPS to lead an inclusive process to evaluate and recommend policy options that could achieve the state's GHG reduction goals and the CEP's 90% renewable energy goal. This process culminated in the 2013 Total Energy Study.[231]
  - Regional Energy Planning: The DPS is funding projects by three regional planning commissions (RPCs) to ascertain their regions' renewable energy potential and to

[231] Vermont DPS, *Total Energy Study*, publicservice.vermont.gov/publications/total_energy_study

comprehensively address their energy needs (electricity, heat, and transportation) through 2050. This initiative is discussed in greater detail later in this section.

- *Concurrent timing of ANR permit filing and CPG — Recommendation #14 (underway)*
  - Requiring full implementation of this recommendation will require a change in PSB rule, but ANR has begun to encourage petitioners to file collateral ANR permits — e.g., stormwater and state wetlands permits — simultaneously with their Certificate of Public Good (CPG) filing. A recent example of this approach is VGS's Addison County Natural Gas Project. While the ANGP is an energy transmission, not a generation, project, it requires the same CPG and many of the same ANR permits as new generation. VGS filed its CPG, state wetlands, stormwater, and water quality certification applications all on the same day, allowing for the simultaneous update and review of complex resource data.
- *ANR response in keeping with performance standards — Recommendation #16 (underway)*
  - ANR's Department of Environmental Conservation (DEC) has established permit processing performance standards — or expected processing timelines — for a number of permits relevant to energy generation. ANR is actively working to streamline internal processes and re-allocate capacity to ensure that these standards are met. While meeting performance standards is a goal for all DEC permitting, the high volume and tight timelines of many energy generation projects have made that sector a priority for the Department.
- *Update environmental, health, and other standards and guidelines — Rec. #21 (underway)*
  - Across all three ANR departments, technical staff and scientists have begun to update policies and guidance documents related to energy generation. In some cases new technical guidance has been developed. By providing petitioners with technology-specific guidance and standards for solar, wind, biomass, and natural gas projects, CPG applications are typically more complete and better address natural resource considerations, resulting in a more efficient regulatory review process.

Regional Energy Planning Pilot

In early 2015, the DPS funded three RPCs — Bennington County, Two Rivers-Ottauquechee, and Northwest — in a two-year pilot initiative to develop detailed energy components of each RPC's regional plan pursuant to its related statutory responsibilities as required by 24 V.S.A. Chapter 117, Subchapter 3. The energy plans are expected to help achieve the state's energy and climate goals while being consistent with local and regional needs and concerns, and to provide specificity to enable progress of each region toward those goals.

The work being performed by the RPCs covers three key areas: (1) identification of an overall statewide policy framework that will help guide the establishment of regionally appropriate targets for specific energy conservation, generation, and fuel-switching strategies; (2) development of comprehensive regional energy plans that include specific strategies for conservation, energy efficiency, and reduced use of fossil fuels; and (3) a geographic analysis that identifies energy resources and the most appropriate locations for new renewable (thermal and electric) energy generation projects, including an estimate of the theoretical potential generation from identified high-potential areas.

The RPCs are working with VEIC to develop regionally appropriate energy scenarios and strategies for each region using the Long-Range Energy Alternatives Planning (LEAP) model, including targets for conservation, renewable thermal and electric energy generation (local and/or imported), and fuel-switching targets. The RPCs will work iteratively with their towns to refine draft scenarios, resource maps, and strategies with the ultimate goal of producing draft regional energy plans for potential adoption into the overall regional plans.

By early September 2015, all three RPCs had completed draft resource potential maps and LEAP modeling and were preparing to bring their results to local communities for feedback. As the project proceeds, the DPS and the RPCs will gain a better understanding of the value of the work, which may prove useful and replicable for the state's eight other RPCs.

Solar Siting Task Force

The Solar Siting Task Force was created by the Legislature with the passage of Act 56, signed into law on June 11, 2015.[232] It directed the DPS commissioner to call the first Task Force meeting on or before August 1, 2015. The Task Force's duties are to study the design, siting, and regulatory review of solar electric generation facilities, and to provide a report in the form of proposed legislation with the rationale for each proposal.

Act 56 also contains specific measures designed to address concerns that legislators heard from constituents, related primarily to the aesthetics of solar projects. These include:

- Giving automatic party status in Section 248 proceedings to host municipal legislative bodies and planning commissions.
- Creating statewide setbacks for ground-mounted solar projects:
  - Solar projects larger than 15 kW and smaller than 150 kW must be set back 40 feet from the edge of a state or municipal highway, and 25 feet from adjoining property boundaries.
  - Solar projects larger than 150 kW must be set back 100 feet from the edge of a state or municipal highway, and 50 feet from adjoining property boundaries.
- Granting screening authority to towns:
  - Allows municipalities to adopt a freestanding solar-screening bylaw, and to make recommendations to the PSB on applying the bylaw to a ground-mounted solar facility.

232 legislature.vermont.gov/assets/Documents/2016/Docs/ACTS/ACT056/ACT056%20As%20Enacted.pdf

- Requires ground-mounted solar facilities to comply with screening bylaws or ordinances, unless the Board finds that compliance would prohibit or have the effect of prohibiting the facility's installation or functional use.

The Task Force will review the siting of solar projects in the context of these new requirements, and is also directed by the Legislature to review a forthcoming ANR report on the environmental and land use impacts of renewable electric generation in Vermont. To date, the group has reviewed the findings of the Siting Commission as well as a number of background documents available on the Task Force website.[233] It has also begun the ongoing process of listening to towns, neighbors, and members of the public to understand ongoing and evolving concerns with solar siting.

Net Metering and Renewable Energy Standard Design

Two renewable energy rule design processes are currently underway that provide opportunities to recommend improvements to the siting and review aspects of these types of projects.

Act 99 of the 2013-2014 legislative session amended the state's net metering law, and created a process to revise the rules under which net metering projects are reviewed by the PSB.[234] In its initial comments to the Board, the DPS proposed as part of its rate structure construct that rooftop projects and those sited on parcels with reduced economic or environmental potential receive additional credit, in order to level the playing field between these typically more challenging sites and those that are easier to develop, such as greenfields.[235]

Act 56 created a Renewable Energy Standard (RES), which is discussed at length elsewhere in this chapter. The PSB opened Docket 8550 in August of 2015 to address issues related to implementing the RES.[236] The process of developing rules for implementing the RES may offer opportunities to address siting aspects of renewable energy generators, above and beyond the characteristics prescribed in the underlying legislation. Understanding how siting is addressed in the RES equivalents in other states will be especially helpful as the Docket 8550 process unfolds.

General Regulatory Improvements

Several state agencies have played an active role in each of the siting initiatives discussed above, and have made or are making specific recommendations. As statutory parties to the Section 248 process, and in their day-to-day interactions with towns and neighbors of renewable energy projects, the DPS and

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233 Vermont Solar Siting Task Force, solartaskforce.vermont.gov/

234 psb.vermont.gov/statutesrulesandguidelines/proposedrules/rule5100

235 psb.vermont.gov/sites/psb/files/20150612%20Act%2099%20Workshop%20Comments%20of%20the%20Department%20of%20Public%20Service.pdf

236 psb.vermont.gov/docketsandprojects/electric/8550

ANR also have a broader perspective on the benefits and drawbacks to the existing systems for siting and review of all sizes and types of renewable energy projects.

Some of the elements of the Section 248 process that may benefit from revision in the near term include:

- *Consideration given to agency permits in the Section 248 process.* This includes ANR's permits related to natural resource considerations that are reviewed separately (and potentially redundantly) in Section 248, as well as pre-existing conditions in Act 250 permits that run with a piece of land on which an energy project is proposed, but which are not necessarily incorporated (or may in fact be contravened) in a Section 248 review and approval.

- *Section 248 rules and requirements for different sizes and types of renewable energy projects.* The current system is disjointed and lacks clarity in terms of applicable statutory criteria, requirements for application completeness, information required to demonstrate compliance with the statutory criteria, and the process and requirements for submitting comments, requests for intervention, and hearings.

- *Roles and responsibilities of the DPS and other state agencies*. Particularly in net metering proceedings, the roles of statutory parties and state agencies that have expertise and authority to provide information on relevant statutory criteria (including but not limited to the State Division of Historic Preservation, the Agency of Transportation, and the Department of Health) are not entirely clear in terms of requirements for hearing requests, imposition of particular conditions, and raising concerns about the extent and nature of the impacts a project may have on the Section 248 criteria.

- *Timelines.* Towns, neighbors, and parties require sufficient opportunity and time to comment effectively on CPG petitions and applications. At the same time, the process would benefit from timelines for issuance of Board decisions on applications and petitions where no issues have been raised.

Recommendations

(1) The state should evaluate the impact of the solar siting reforms contained in Act 56 of 2015 and consider the recommendations to be made by the Solar Siting Task Force.

(2) The PSB should implement the ePSB electronic filing system as soon as possible.

(3) The DPS should continue to advocate for financial incentives and regulatory and other tools to encourage siting of renewables as appropriate on the built environment, other disturbed lands such as brownfields, and in places that offer the opportunity for optimizing multiple uses, such as grazing and recreation or parking in conjunction with solar arrays.

(4) *The state should review the preliminary outcomes of the Regional Planning Commission energy planning pilot and, if positive, seek funding for the remaining eight RPCs as soon as possible, as well as continuing to work closely with RPCs as they assess their regions' energy needs, opportunities, and challenges.*

(5) *State agencies should continue to work with municipal legislative bodies, planning commissions, and energy committees as well as partners such as the Vermont League of Cities and Towns, Vermont Planners Association, and the Vermont Energy and Climate Action Network to provide tools and training to enhance local and regional energy planning, community-led project development, and regulatory process participation.*

Electric Equivalents for Renewable Generators

Electric generators are often compared on the basis of their generation capacity, expressed in megawatts (MW) or kilowatts (kW). But different kinds of generators operate differently, and produce different amounts of energy per unit of capacity. A generator that runs at its maximum all the time is said to have a capacity factor of 1. A generator with the same capacity, but which outputs only 20% as much energy over the course of the year, has a capacity factor of 0.2. This table shows illustrative capacity factors for different kinds of renewable electric generators.

Illustrative Capacity Factors for Renewable Electric Generators

Fuel	Capacity Factor
Solar	0.16
Wind	0.33
Methane	0.95
Biomass	0.75
Small Hydro	0.45

Using these capacity factors, one can determine the electric energy equivalence of different generators. For example, each of the follow generators might be expected to generate approximately the same amount of annual electric energy (about 60 GWh, or 1% of Vermont's annual electricity use):

- A 20 MW wind project, consisting of eight 2.5 MW turbines, or half the size of the Sheffield wind project.
- 44 MW of solar PV, using a land area of approximately 300 acres if ground-mounted, or roughly equivalent to the cumulative capacity of all the solar PV deployed to date under the Standard Offer program.
- 15 MW of run-of-river hydroelectric generation, or approximately three times the size of GMP's Waterbury Dam hydroelectric generator.
- 9 MW of woody biomass electric generation, or slightly less than 1/5 the size of the McNeill generating station in Burlington.
- 7 MW of anaerobic digestion, or somewhat more than all of the currently operating anaerobic digesters in Vermont.

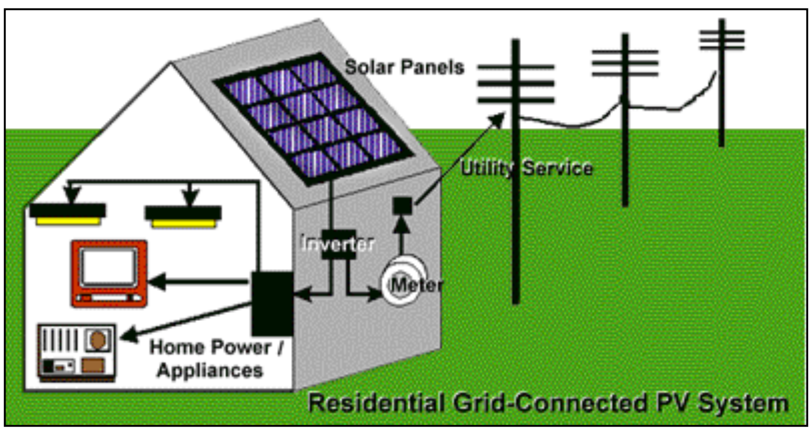
11.2.2 Strategies for Shaping In-State Renewable Energy Development

Vermont is blessed with renewable energy resources, access to electricity from a wide array of in-state and regional sources, and connection to three different power grids that are all larger than our in-state system. However, policy support is required to ensure that the electric-sector portfolio contributes to meeting the overall CEP goal of renewable sources meeting 90% of total energy needs by 2050.[237]

Broadly, the CEP recommends that utilities secure renewable power generation of all sizes, from small residential systems to large utility systems. The policy tools discussed here can be seen as directed to facilitate three different sizes of generation projects: residential, community, and utility-scale. Some of the policy tools needed to encourage each are discussed below.

11.2.2.1 Sustain Net Metering

The 1998 legislative session enacted a net metering law (30 V.S.A. § 219a), requiring electric utilities to permit customers to generate their own power using small-scale renewable energy systems. The excess power generated by these systems can be fed back to the utility, basically running the electric meters backward and providing customers with a credit on their monthly electric bill.



Net metering thereby provides customers with the ability to offset their use of utility-supplied power with power generated on the customer side of the meter, by a customer-owned renewable source. Combined heat and power systems of less than 20 kW that use fossil fuels are also allowed, but none have been installed.

The net metering law was amended in 1999, 2002, 2008, 2010, 2011, 2013, and 2014. Over time, these changes established a mature program that:

[237] Electric efficiency, the most cost-effective supply resource, is discussed in Chapter 10.

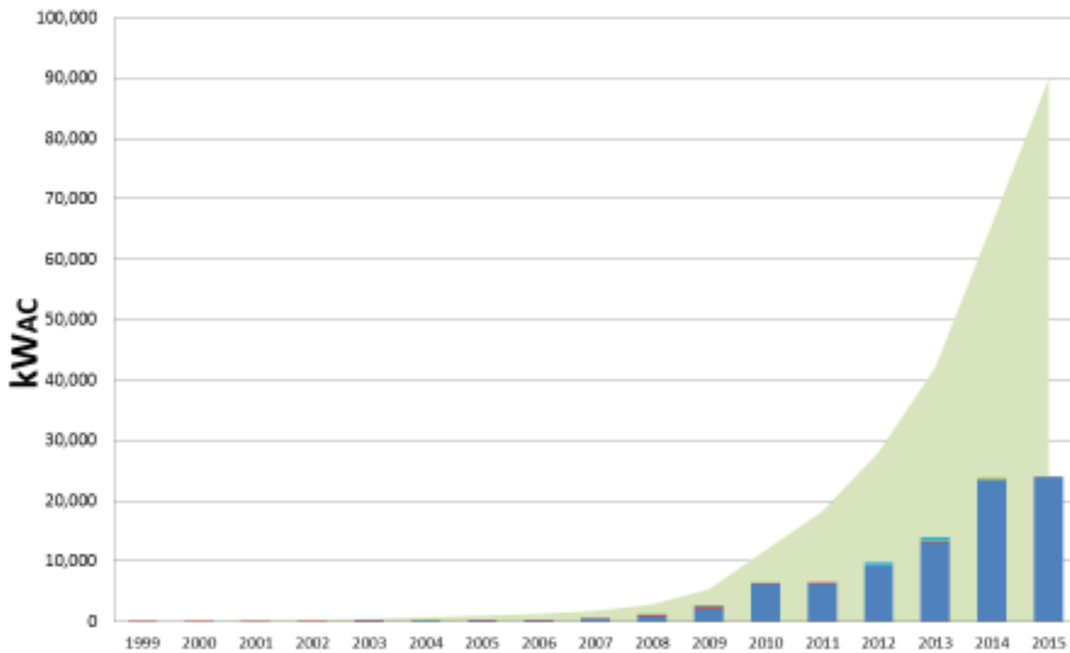
- Has a cap per utility of 15% of 1996 utility system peak[238] or previous year's peak (whichever is higher),
- Allows systems up to 500 kW, with additional limited opportunity for systems up to 5 MW for economic development or on closed landfills,
- Opens group net metering for all customers,
- Has a registration permitting and interconnection process for solar PV systems under 15 kW,
- Adds a solar credit that has the effect of increasing the customer value of net metering to 20 cents per kWh for systems under 15 kW, and 19 cents per kWh for larger systems, and
- Allows electric cooperatives to pilot alternate net metering structures.

Exhibit 11-5 shows that Vermont's legislative action, along with increased awareness and the availability of incentives, has led to a dramatic increase in permitted net metered capacity since 1999, especially for solar systems. In 2006, there were only 329 permitted net metered systems in Vermont, with an installed capacity of 1.2 MW. By the beginning of 2011, the numbers had climbed to 1,319 installed systems with an installed capacity of just under 11 MW. By November of 2015, more than 6,200 systems had received permits, and capacity approached 90 MW. An additional 35 MW of projects are awaiting permits. Solar PV dominates net metering, with 97% of all systems, over 95% of capacity, and 88% of energy generation using this technology.

As of December 2015, four utilities approached or exceeded their statutory capacity caps for net metering, when taking interconnection requests into account. Green Mountain Power has asked the Public Service Board to raise its cap by 7.5 MW for 150-kW-scale projects, and indicated that it will not limit systems of 15 kW and less.

[238] *Peak demand* means the highest monthly peak reported in either the electric company's FERC Form 1 or the electric company's Electric Annual Report to the Vermont DPS for the year.

Exhibit 11-5. Net metered Permitted Capacity by Year and Type



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Cumulative Capacity	50	99	176	228	441	675	986	1,261	1,758	2,808	5,324	11,781	18,186	28,049	42,066	65,787	89,871
Hydro	-	-	-	-	-	-	-	-	-	-	18	-	-	716	684	-	380
Methane	-	-	-	-	-	65	-	-	-	19	39	127	-	-	248	293	-
Wind	32	10	28	31	98	72	124	102	149	158	482	154	239	66	125	98	99
Solar	18	39	49	22	114	97	187	174	347	874	1,976	6,176	6,166	9,081	12,980	23,331	23,624

Source: DPS, data through November of 2015

As the above data shows, net metering has been an increasingly effective tool to promote residential and small commercial renewable energy systems. It took off as a way for homeowners to invest in renewable energy generation equipment on their own roof. As interest has grown among both customers and the utilities, and experience has shown no adverse impacts to system reliability, the state has raised the cap continually to maintain access to net metering for all customers.

As net metering has met a rapidly increasing portion of Vermonters' electric energy needs, the question of appropriate and fair monetary compensation for net metered generation has risen in prominence. The DPS published analyses in 2013 and 2014 showing that on a statewide basis, solar PV net metering under the state's current structure produces minimal net subsidy between net metered and other customers, when viewed over the 20-year life of the generator, accounting for energy, capacity, renewability, and infrastructure benefits. The sources of distributed power that can be net metered have some potential to affect the need for transmission and distribution investment to the benefit of all ratepayers. However, there is significant variability between utilities, due to different infrastructure designs (distribution systems designed to meet winter vs. summer peaks) and different retail rates.

Act 99 of 2014 transitions net metering, from a structure in which many details are established in statute to one in which the PSB designs the details of the program within a broad statutory framework. The PSB has been charged to design a program that:[239]

- Advances the goals and total renewables targets of 30 V.S.A § 8001, 8004, and 8005 and the goals of 10 V.S.A. § 578 (GHG reduction), and is consistent with the criteria of 30 V.S.A § 248(b);

- Achieves a level of deployment consistent with the recommendations of the Electrical Energy and Comprehensive Energy Plans under sections 202 and 202b of Title 30, unless the Board determines that this level is inconsistent with the goals and targets identified in the first item above. The Board shall consider the plans most recently issued at the time the Board adopts or amends the rules;

- 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;

- 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;

- Ensures that all customers who want to participate in net metering have the opportunity to do so;

- Balances, over time, the pace of deployment and cost of the program with the program's impact on rates;

- Accounts for changes over time in the cost of technology; and

- 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:

    - ° 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

    - ° If the customer transfers the attributes to the interconnecting provider, requires the provider to retain them for application toward compliance with the Renewable Energy Standard.

[239] The text that follows is from 30 V.S.A. §8010, adapted to this CEP context.

The PSB concluded an initial working group phase for its development of rules that fulfill these requirements during the summer of 2015. The PSD has released a draft rule for public comment; it is expected to complete its revision and rulemaking process in the coming months.

Over the coming years, net metering has great potential to be a primary method for the development of small-scale renewable electric generators in Vermont. Tier 2 of the Renewable Energy Standard requires development of new distributed generation at a sustained pace, likely to exceed 20 MW per year for the next 15 years. Because net metering provides an appropriate tool to develop a significant portion of this generation, it is critical that the state implement a program that is financially sustainable over the long term and avoids boom-and-bust cycles. This requires allowing participation from a wide range of possible customers, in each utility service territory, while being financially sustainable for both participating and non-participating customers, as well as for the firms that develop and install generators.

In the PSB stakeholder process, the DPS advocated for a net metering program that explicitly reflects the value provided by generators, while providing stable and predictable bill credits to participating customers, allowing customers to access low-cost capital. Value can take the form of explicit ratepayer value (such as energy, capacity, and transmission and distribution infrastructure costs) and environmental value (such as Renewable Energy Credits that can meet the requirements of Act 56). Of particular note is the DPS's proposal to value avoided land use impacts from net metered generators located on buildings, brownfields, closed landfills, and other disturbed lands. By reducing land use impacts, recognizing such siting-related value will increase the program's long-term sustainability.

Recommendations

(1) *The PSB and DPS should continue to work with stakeholders to design and implement a financially sustainable net metering program meeting the requirements of Act 99, and contributing appropriately to the RES.*

(2) *The PSB should implement, as soon as feasible, an online process for submission of net metering application and registration forms. This process should allow utilities and the DPS to maintain databases regarding the permit and interconnection status of each generator.*

11.2.2.2 Study the Standard Offer Program

The Standard Offer program was established in 2009 as a 50 MW feed-in-tariff program, providing to developers of small qualifying renewable generation projects a fixed price for power under long-term standard contracts. The program was directed at certain renewable technologies and at projects of 2.2

MW in size or smaller. Power from each generator is allocated among Vermont's utilities on a pro-rata basis[240].

To ensure rapid development of the qualifying renewable technologies, the Legislature mandated that the rates paid reflect the actual costs of the various renewable technologies. The rates proved attractive, and the initial 50 MW allocation quickly was fully subscribed. Nearly all generators awarded a contract from this original tranche are now operating. The 2011 CEP proposed expanding the program, using market forces to set the prices, rather than an administrative process. Act 170 of 2012 added 77.5 MW of additional capacity to the program, to be added in annual increments of 5 MW for each of three years, then 7.5 MW for each of three years, followed by 10 MW for each of four years. By 2022, contracts totaling 127.5 MW will be awarded. Many of these generators will be among the primary generators that utilities use to meet the Tier 2 distributed generation requirements of Act 56. Each year's allocation allows for both independent providers and utility-owned projects.

To date, contracts have been awarded to 68 generators with a total capacity of 71.8 MW. This includes 38 solar PV systems totaling 59 MW, six small wind projects totaling 520 kW, six hydroelectric projects totaling 4.9 MW, two woody biomass CHP projects totaling 1.2 MW, one landfill methane project of 560 kW, and 15 farm methane projects totaling 5.4 MW. In all, 51 projects totaling 52.6 MW are now operating.

The Standard Offer program has also been expanded to house non-net metered farm methane generators that had previously been fostered by a separate "cow power" program. These generators do not count toward the programmatic cap. Generators that provide "sufficient benefit" to the operation of the electric grid may also be awarded contracts outside of the cap.

The market-based pricing structure established by Act 170 has been very successful at reducing the cost of the Standard Offer program. For each technology, the PSB establishes a cap, based on the expected cost to develop that technology, and projects compete for limited capacity by offering prices at or below that cap. Where the legislative and PSB processes that established prices for solar PV in the initial phase of the program have set prices between $0.24 and $0.30 per kWh, the most recent request for projects resulted in contracts offered at under $0.11 per kWh.

The Standard Offer program should be diverse among different types of generation. The most recent solicitation, for example, established separate tranches for solar PV and for other types of generation, such as small wind, hydroelectric, and non-farm methane. Given its limited capacity each year, along with technology-based price caps, the Standard Offer program is well-suited to fostering new renewable generation technologies that may not be able to otherwise attract power-purchase agreements or net metering customers, while limiting ratepayer exposure to higher costs through its annual cap and competitive process. Allocation of annual capacity to a diverse range of technologies diversifies utility portfolios, and supports the emergence of technologies and firms that may later be able to compete on

[240] Washington Electric Cooperative has been exempt from this program due to the composition of its power portfolio.

price and performance alone. Establishing additional differentiation — such as between solar PV sited on disturbed land or in the built environment and solar PV in general — could further allow the program to foster otherwise under-represented types of generation.

The market-based Standard Offer program is set to continue throughout the period of this CEP. It has proven to be relatively flexible (e.g., the tranche system that attracted wind, hydroelectric, and methane projects in 2015) while remaining cost-effective. As implementation begins for the Renewable Energy Standard, which requires utilities to acquire RECs from projects very similar to Standard Offer projects, the continued need for a program of this sort after 2022 is uncertain.

Recommendations

(1) *The DPS, PSB, and Legislature should consider whether the Standard Offer program could be effectively used to increase development of solar PV in the built environment or on disturbed lands.*

(2) *Before 2022, the DPS should evaluate the existing Standard Offer program in the context of the RES to determine whether the program should be extended or if a successor program of a different sort is warranted.*

(3) *The PSB should continue to use its authority to foster deployment of diverse resources through the Standard Offer program.*

11.2.2.3 Interconnection Standards

Among the regulatory barriers identified by proponents of distributed resources are those associated with uncertain costs and requirements regarding interconnections to the grid. The Legislature has responded to this concern by requiring the PSB to establish simplified interconnection rules for small systems (<150 kW), an even simpler system for the smallest solar PV systems (<15 kW), and clear standards and a timeframe for responding to interconnection requests of larger systems.

These rules created by the PSB for small systems below 150 kW and very small solar PV systems below 15 kW have worked well to ensure safe and timely interconnections of more than 6,000 net metered systems. The interconnection rule developed for larger systems (>150 kW, Rule 5.500) is similar to rules for interconnection governed by FERC and ISO-NE. These rules are fundamentally designed to ensure timely response to a generator requesting interconnection, and to filter or distill material projects requiring significant analysis and review of distribution and transmission system impacts. Where additional facilities are required to ensure system integrity, the requester must pay the costs. The requester is also required to pay the costs associated with any system impact or facility studies required.

As they have processed thousands of interconnection requests in the last several years, Vermont's utilities have gained a great deal of experience at identifying common issues with interconnection requests, and addressing them in a way that supports the reliability of the electric grid while quickly and fairly addressing each request. Utilities have also identified the need for additional flexibility in the Rule 5.500 interconnection process applicable to larger systems, allowing for the identification, without a long and expensive study process, of simple changes to the configuration of the grid necessary to accommodate a generator. In the future, some projects below 150 kW may require a more robust analysis than the current system allows, due to clustering or cumulative effects with other generators on a circuit.

The DPS coordinated a working group process during the summer and fall of 2015 to develop a suggested modification to Rule 5.500 to address these concerns. The group's draft rule will also explicitly allow for and define processes for interconnection of electric energy storage; clarify the applicability of various electric codes; allow for the deployment of smart inverters that can allow generators to provide grid support (rather than tripping offline at the first sign of trouble, potentially exacerbating an issue) once relevant codes and standards are updated; and require the PSB to host a centralized online interconnection application system. The DPS with petition the PSB to begin a rulemaking and adopt the new rule in early 2016. The DPS obtained DOE grant support for this project through a competitive State Energy Program solicitation.

In parallel with the rule update, the DOE grant is also supporting Green Mountain Power in developing a "solar map" that will make freely available, through an online map application, detailed grid information of the sort necessary to evaluate a potential location for interconnection. The solar map will allow project developers to identify sites where projects will be most easily able to interconnect, and where generators could provide particular value to the operation of the grid. An early version of this solar map is now online[241].

As in-state electric generation increases, grid constraints could begin to restrict the locations where generators may cost-effectively be sited, due to high interconnection costs or curtailed production associated with the current "cost causer pays" approach to interconnection costs. A location's capacity to reliably interconnect a generator depends on the minimum load and export capacity of the relevant portion of the grid. For resources distributed relatively evenly across the state, like solar PV, this will serve to encourage wider geographic dispersion of generators, and siting near load. Where the renewable resources are more concentrated, such as with wind or hydroelectric, this could result in a barrier to effectively using the state's resources.

Recommendations

(1) The utilities and regulators should continue to ensure that interconnection arrangements, business response timetables, and relevant tariffs are fair and nondiscriminatory.

(2) The PSB should promptly act on the Interconnection Rule Working Group's recommended changes to Rule 5.500, including development of an online interconnection application.

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[241] gmp.maps.arcgis.com/apps/Viewer/index.html?appid=546100cc60c34e8eb659023ea8ae03f3

(3) *Vermont utilities should learn from Green Mountain Power's experience developing the solar map to make timely interconnection-relevant information freely available statewide.*

(4) *In order to most effectively utilize in-state renewable resources, the DPS, PSB, distribution utilities, and VELCO should consider alternatives to the "cost causer pays" paradigm.*

11.2.2.4 Maintain Existing Renewable Generation

Meeting long-term renewable electricity and energy goals requires maintaining existing renewable electric generation in Vermont, in addition to the development of new resources. Because many generators now online have been fully depreciated or have paid off loans related to their construction, they can often be cost-effectively maintained and operated at costs at or below the cost of new generation. Many older facilities are hydroelectric generators, and occupy a large fraction of all of the potential dam sites for hydroelectric generation. The loss of such systems could result in an irreversible loss in in-state hydroelectric generating capacity. Hydroelectric generation is variable with water flow, but varies differently over time than do other variable generators such as solar PV and wind, providing valuable diversity in in-state generation.

Recommendations

(1) *The state should work to maintain existing renewable electric generators, provided that the plants can be operated cost-effectively compared to new renewable energy generation.*

(2) *Vermont utilities should explore opportunities to purchase independently owned renewable electric generators as well as similar new generation projects currently under non-utility development, if such purchases would lower ratepayer costs in comparison to continued independent ownership.*

(3) *Vermont utilities that own renewable electric generators should actively maintain and, where cost-effective, enhance them to enable long operating lifetimes and low-cost electricity.*

11.3 Regional and National Context

The first electric systems were mostly small, disconnected generation resources that met local needs — such as a small hydroelectric facility that provided electricity for homes and businesses in the immediate area. As efforts to provide electricity to all Vermonters grew, these systems were connected, and generation in one town began to serve generation in other areas. And as these interconnections grew, so did the size of the generation sources providing energy — from kW-scale hydroelectric facilities in the late 1800s to gigawatt-scale nuclear facilities in the 1970s. The creation of larger generating facilities increased the need for transmission that could enable significant amounts of electricity to flow from one area to another. To formalize the process for coordinating generation and transmission planning, the New England electric utilities created the New England Power Pool (NEPOOL) in 1971.

The federal government regulates these interconnections between electric utilities through the Federal Power Act, which grants to the Federal Energy Regulatory Commission (FERC) authority over the "transmission of electric energy in interstate commerce" and the "sale of electric energy at wholesale in interstate commerce."[242] The term *interstate commerce* does not limit federal jurisdiction to transactions that happen outside Vermont borders: it covers any transmission of energy from one utility to another, and any sale of energy that does not involve the ultimate end user. FERC reviews these transactions to ensure that they result in just, reasonable, and non-discriminatory rates.

In 1999, in response to FERC directives to transmission companies regarding open-access principles, NEPOOL formed ISO-NE. This entity was designed to operate the New England electric system; over time, its responsibilities increased to include comprehensive planning of the transmission system and designing and administering the wholesale electricity markets. Under the Federal Power Act, ISO-NE has the authority to file proposed changes to wholesale markets and transmission tariffs, while FERC is required to find that market rules and transmission tariffs are just, reasonable, and not unduly discriminatory.

NEPOOL has evolved over the years, but continues to have a role in the design of the wholesale electricity market and transmission planning efforts. Now the formal stakeholder in ISO-NE's review of wholesale market rules and transmission planning, NEPOOL is composed of six sectors: transmission owners (entities such as VELCO that own transmission infrastructure), public power (cooperatively and municipally owned utilities, including the Vermont municipal and cooperatively owned utilities), alternative resources (including efficiency and demand response providers such as EVT), generators (entities that produce power), end users (entities that represent consumers, such as state public advocates and environmental groups), and suppliers (entities that provide power for customers in restructured states, which does not include Vermont).

ISO-NE is required to present proposals to NEPOOL, which then provides an advisory vote on the proposals. ISO-NE may file proposals even with zero support from NEPOOL; but in theory, FERC takes into consideration NEPOOL's support for an ISO-NE proposal. There are also two multistate entities that participate in these processes. The New England States Committee on Electricity (NESCOE) is funded by ratepayers and managed collectively by the New England states, with the governor's office of each state appointing one or more managers. The New England Coalition of Public Utility Commissioners (NECPUC), which consists of the public utility commissions, helps provide oversight of the ISO-NE budget and works with NEPOOL and NESCOE.

11.3.1 Wholesale Electricity Markets

The wholesale price of electricity in New England is set through competitive wholesale markets, in which resources (primarily generation, energy efficiency, and demand response) bid to be able to provide power

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[242] Federal Power Act § 201(b)(1)

or other services. An individual resource may be able to provide the electric system with multiple benefits:

- *Energy*, measured in MWh, which is the actual electrons that flow across the line;
- *Capacity*, measured in New England as kW-month, which is the ability of a resource to be able to provide energy when called upon; and
- *Ancillary services*, or the ability to operate the resource in a way that ensures the maintenance of system stability.

To determine the appropriate price paid for each of the attributes listed above, ISO-NE administers the following competitive wholesale markets.

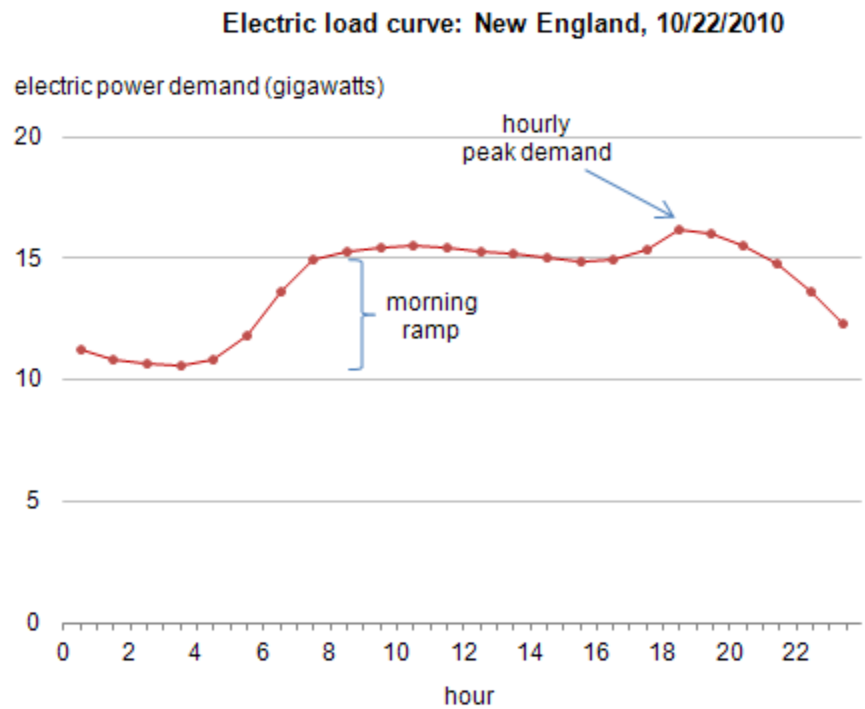
Energy Market

The energy market is composed of two markets: one *day-ahead market,* which is used for planning purposes and creates financially binding obligations by generators to provide power; and a *real-time market,* which recognizes that fluctuations will occur in consumer demand, either as a result of an incorrect weather forecast (a day that was forecast as mild turns out to be hot and muggy, causing people to turn on air conditioners) or because of an outage at a generator or a transmission line that prevents a resource from providing energy into the grid.

In the day-ahead market, load submits demand bids — statements that the utility needs a certain number of MWh at any given instance, over five-minute periods throughout the day. Generators submit supply bids, stating that they will provide a certain number of MWh in five-minute increments at a certain price. ISO-NE selects the least expensive resources to supply the total number of MWh needed. The last unit selected, the one at the margin, is called the *marginal unit,* and the price that it bid is called the marginal price. All generators that produce energy are paid this marginal price for every MWh bid.

The amount of power needed shifts throughout the day and is commonly referred to as a *load curve*. Typically there is limited power needed during the early morning hours, with a steep curve upward from 5 a.m. to 8 a.m., as people are getting ready for work (often referred to as the morning ramp), and then relatively steady load until peak demand is hit around 6 p.m., as people arrive home, with load dropping off again as people begin to go to bed around 10 p.m.

Exhibit 11-6. Electric Load Curve: New England, 10/22/2010



The cost of power during the day typically corresponds to the need for MWh. In the early morning hours, there is limited need for power, so only the least expensive units are typically online. During the morning ramp, ISO-NE will need to call upon (dispatch) an increasing number of units, climbing up the cost curve for resources, with these units maintained during the day. ISO-NE will then need to dispatch even higher priced units for the day's peak hour.

Any generator that is smaller than 5 MW may act to reduce the load within the interconnection utility, rather than participate in the energy market. For example, a 4 MW solar facility in Vermont may have a contract with the Vermont utility with which it is interconnected. The generator is paid directly by the utility; in this scenario, ISO-NE does not account for the generation in its dispatch, but instead sees a reduction in the utility's load, and the utility does not need to buy the number of MWh produced by the solar facility when it is producing power. The value of these resources corresponds to the cost of the power that would otherwise be purchase by the utility. For example, a solar facility that reduces load during peak hours, when the wholesale market prices are highest, reduces the need to buy high-cost power, while a resource that produces mainly in early morning hours only offsets the need to purchase low-cost power.

Capacity Market

The New England electric system is designed to provide power whenever called on. To do so, ISO-NE must plan for all load levels, including very hot days when everyone wants to run their air conditioning. Depending on the season, the peak demand can range from 15,000 MW in the spring or fall, to 20,000 MW during the winter and 28,000 MW during the summer. The particular hour of the particular day with the highest load level is called *peak demand*, and ISO-NE ensures that the system can meet that need.

ISO-NE predicts the peak demand three years into the future, and adds a reserve margin. This amount is called the *installed capacity requirement* — how many resources are needed to meet this peak requirement. Unlike the energy market, which is responding to specific needs for electricity at any given period in time, capacity requirements can be met by several types of resources. Generation can provide power when called on (although many generators can take hours to ramp up to full production); energy efficiency is a resource that is always considered to be "on" during certain hours; and demand response is the reduction of load, typically in response to high energy prices.

After determining the installed capacity requirement, ISO-NE conducts a *forward capacity auction* to purchase the amount of capacity required. ISO-NE selects resources based on the lowest price first, and then goes up the supply stack until the requirement is met. Those resources that clear in the auction receive a *capacity supply obligation*, in which the resource agrees to provide power (or reduce load) when called upon. A resource will incur financial penalties to the extent that it does not meet its capacity supply obligation.

Ancillary Services Markets

To account for potential contingencies such as a generator or transmission outage, ISO-NE maintains *reserve resources*. There are three types of reserves:

- *Ten-minute spinning reserves* are generators that are already operating but are not producing at full power. These resources can ramp up power production within 10 minutes to provide power as needed.
- *Ten-minute non-spinning reserves* are generators that are not online but have demonstrated that they are able to start and be able to produce a certain amount of power within 10 minutes.
- *Thirty-minute non-spinning reserves* are generators that are not online but have demonstrated that they are able to start and be able to produce a certain amount of power within 30 minutes.

ISO-NE requires that, at all times, there are sufficient 10-minute reserves to meet the largest single contingency (for example, an outage by the largest generator operating within New England), and that between a quarter and half of the 10-minute reserves consist of spinning reserves. The rationale for having spinning reserves is that the single largest occurrence of generator failure is during startup; since these generators are already producing power, they are much more likely to be able to increase production within 10 minutes and provide the necessary reserves. The amount of 30-minute reserves must be equal to the amount needed to meet one-half of the second largest contingency.

In addition to the reserve markets, ISO-NE manages a *regulation market*. In this context, *regulation* means the ability of generators to increase or decrease output every four seconds to respond to small changes in the electric system.

Participation in the Wholesale Markets

Each of Vermont's distribution utilities is required under the ISO-NE tariffs and market rules to participate in the wholesale markets described above. To protect against market volatility, utilities can enter into bilateral contracts with resources for energy and capacity needs. These resources are still entered into the markets; however, the utility will pay only the contract price to the resource, rather than the market price. For example, if a utility has a long-term contract for energy from a generator for $60/MWh, the price the generator is paid through the wholesale market will vary according to hourly market prices, and will often be above or below that price. Regardless of the wholesale price, the generator receives $60/MWh from the utility, providing the generator revenue stability and the utility rate stability.

Although the utility will likely be paying higher than market prices at some times during the year, it will have estimated the long-range market price of energy and determined that the contract price is an appropriate hedge against market volatility. Vermont utilities are typically more heavily hedged against market price volatility, through bilateral contracts, than utilities in other states.

The Vermont regulatory role in the wholesale market process is typically an after-the-fact review of a utility's long-term contracts during a rate case; or, for larger contracts, a before-the-fact review in a proceeding under 30 V.S.A. § 248. During these reviews, the PSB can examine whether the utility was prudent in entering into the contract — which would involve testing the reasonableness of the utility's estimates of future wholesale prices, and the efforts the utility undertook in pursuing alternative resource options.

11.3.2 Transmission Planning

ISO-NE produces an annual Regional System Plan that sets forth a forecast of expected peak demand, load, and transmission needs over a 10-year period. Transmission needs are driven by the amount of demand and generation within geographical areas; as a result, the retirement of large generators or significant increases in demand can impact the need for transmission. Additionally, ISO-NE must comply with reliability planning criteria established by national and regional bodies, such as the North American Electric Reliability Corporation and the Northeast Power Coordinating Committee. To the extent that these entities establish more conservative standards, that increases the need for additional transmission.

From 2002 to 2015, ISO-NE has put into service $7.2 billion of transmission infrastructure and expects to spend an additional $4.8 billion on transmission infrastructure for reliability purposes from 2015 to 2025.

The costs of reliability projects are socialized across the region, with each state paying based on its proportion of peak demand. Vermont accounts for about 4% of regional peak demand.

Ensuring a reliable transmission system depends on the location of both load and generation. For example, an area with light load and significant amounts of generation would need sufficiently robust transmission to move the energy generated, and not consumed in the area, to an area of the grid that requires the energy. To maintain system stability and reliability in an area without sufficient transmission, ISO-NE must limit the amount of generation produced in the area; this is referred to as *curtailment*. In northern Vermont there is a significant amount of generation, from in-state hydroelectric and wind resources and from the interconnections to Hydro-Quebec, with low load and a relatively weak transmission system. As a result, ISO-NE has periodically curtailed generation in the area. Adding new generation in the area without upgrading the transmission could result in increased curtailment of existing resources.

Along with the transmission required to meet reliability standards, in 2016-2017 ISO-NE will be implementing FERC Order 1000, a mandate for regional entities to plan for transmission projects necessitated by public policy, and to implement competition in the transmission reliability arena. With respect to public policy projects, ISO-NE and stakeholders will be identifying and reviewing state and local public policies to determine whether transmission can most cost-effectively achieve these policies. To the extent that a project is selected under the Order 1000 process, the costs of this public policy project will be socialized among the region, although through a different formula than that used for reliability projects. Those states with public policies necessitating the transmission project will pay 30% of the project costs, with the remaining costs socialized among the region based on each state's share of regional peak demand.

Prior to Order 1000, the transmission owner that had a reliability need within its service territory was expected to provide a solution to the issue. Order 1000 mandates that the transmission reliability planning process be open to any transmission provider, and it allows transmission owners to compete to address reliability concerns. With the advent of competing transmission proposals, ISO-NE and stakeholders will need to address cost-containment issues. At present, reasonably incurred transmission costs can be recovered from ratepayers regardless of the transmission owner's original cost estimate: if the transmission owner estimated the cost of the transmission project at $250 million and the final costs were $400 million, provided that the expenditures were prudent, that full amount could be recovered in rates. To the extent that developers are competing to build transmission projects, there must be greater certainty with regard to the cost estimation accuracy to ensure the cost-saving potential of competition is realized.

The issue of more accurate cost estimating will be helpful in advocating for greater use of *non-transmission alternatives* (NTAs). These are reliability solutions that do not rely entirely on transmission lines. For example, if peak demand can be reduced in an area through targeted energy efficiency, demand response or small-scale generation, these efforts could be able to make the transmission constraints no longer necessary. ISO-NE has begun to do planning studies that examine the possibility of generation resources and energy efficiency addressing transmission constraints. However, NTAs are at a disadvantage, as the costs of a transmission solution will be automatically paid for by ratepayers, and will be socialized among the region.

In addition to reliability and public policy projects, there have been a number of *merchant transmission projects* proposed within New England. These projects are not funded directly by ratepayers, but instead are funded through charges on the amount of power transported across the transmission line. Included in this category is the New England Clean Power Link, a 1,000 MW proposed line that would be located in Lake Champlain for approximately 100 miles and then underground from Benson to Ludlow, at which point it would interconnect with VELCO's transmission system. The stated purpose of the New England Clean Power Link would be to transport energy from renewable resources located in Quebec to states that are seeking increasing amounts of low-carbon energy. The Public Service Board held hearings on the New England Clean Power Link in October 2015.

This CEP supports well-sited merchant transmission projects that provide access to increased amounts of renewable resources while minimizing financial risk to ratepayers.

11.3.3 Regional Initiatives

A significant issue facing the region is its increasing reliance on natural gas for energy production. Typically, natural gas pipelines are built based on long-term (around 20-year) contracts with gas-distribution companies, estimating the need based on the expected increase in customers for natural gas heating and industrial uses. Generators purchase natural gas from the pipelines based on what they need to produce power. Because the energy markets operate on a day-to-day basis, gas-fired generators are not always certain that they will be called upon to run — or, if called on, how much power they will be asked to produce. If a generator enters into a long-term contract for natural gas, there is the possibility that it will not be called upon to run and must resell the gas, probably at a loss.

As a result of this disincentive for generators to enter into long-term contracts for gas capacity, the natural gas infrastructure in New England has been constructed to meet the needs of heating and industrial customers, and not electric generators. In consequence, during times of peak demand for heating there is insufficient pipeline capacity to meet the needs of the electric system. Instead of gas-fired generation, ISO-NE is required to dispatch oil-fired and coal-fired generation, increasing air emissions and typically increasing costs, as oil tends to be a more expensive fuel than gas. Many of the oil-fired units are more than 50 years old, and most of New England's coal-fired units either have retired or are scheduled to retire within the next few years.

Several New England states have seen significant price spikes as a result of the gas pipeline constraints, and are examining the possibility of establishing a structure wherein electric customers pay for new natural gas infrastructure that relates to the needs of the electric system. There are currently no generators in Vermont that rely primarily on natural gas as a fuel source, and the natural gas pipelines within Vermont are not connected to the rest of the New England system.

Recommendations

It is critical that Vermont:

(1) Continue to work with stakeholders in the region to address natural gas pipeline constraints during periods of cold weather in a manner that minimizes costs to Vermont consumers, addresses emissions from oil- and coal-fired resources, and ensures reliable electric service.

(2) Work with stakeholders to examine reliability planning standards to ensure that the standards are reasonable and appropriately account for the cost to ratepayers of transmission upgrades.

(3) Continue to push for market reforms that allow Vermont to effectively pursue NTAs wherever feasible.

(4) Focus on electric efficiency and peak load reduction, as Vermont's peak demand is used to calculate its share of regional transmission reliability and public policy projects.

(5) Consider the location of proposed large generation resources with respect to the impact on the transmission system and existing resources.

(6) Continue focusing on Vermont's regional participation and advocacy at ISO-NE, FERC, and within regional organizations such as the New England States Committee on Electricity.

11.3.4 The Regional Greenhouse Gas Initiative and the Federal Clean Power Plan

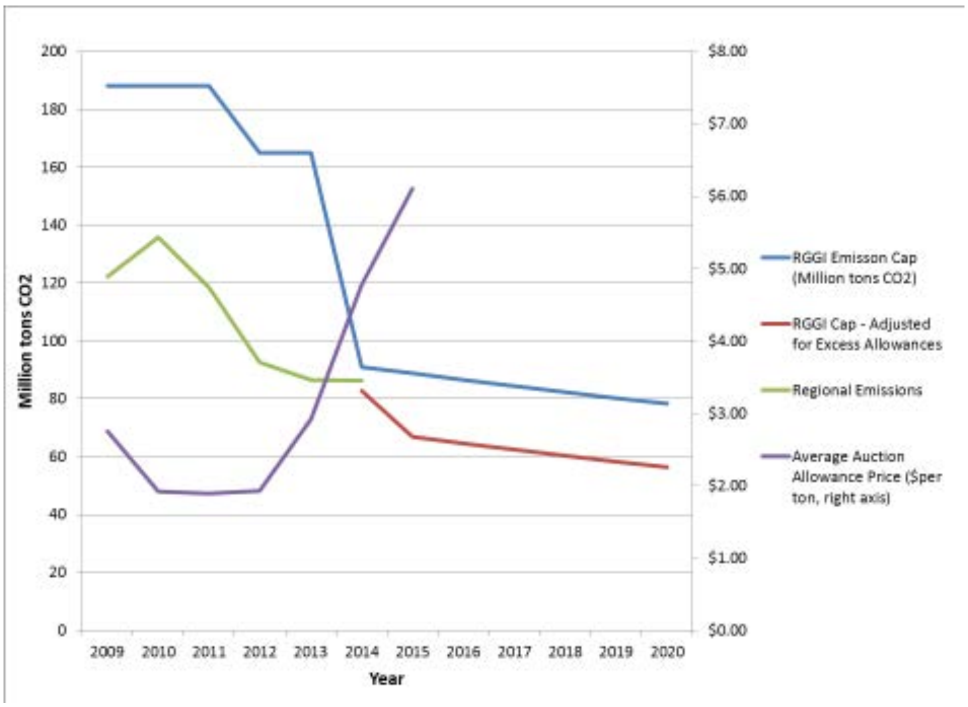
The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by northeastern and mid-Atlantic states to establish a multistate cap and trade program, with a market-based emissions trading system, to reduce carbon dioxide emissions from the region's electricity generating utilities. Nine states now participate in RGGI: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Each of these is represented by energy and environmental regulators; Vermont's representatives are the chair of the PSB and the secretary of the Agency of Natural Resources (or their designees).

The RGGI states have established a regional cap on CO_2 emissions from the electric power sector, and they require certain fossil fuel-fired power plants (25 MW or greater) in participating states to possess a tradable CO_2 allowance for each ton of CO_2 they emit. The states have implemented statutes or rules that limit emissions of CO_2 from electric power plants, create CO_2 allowances, and establish participation in CO_2 allowance auctions. Under RGGI, each participating state is allocated a certain number of allowances during a three-year compliance period. The states collectively auction these allowances on a quarterly basis, and any qualified entity can purchase allowances. There is also a secondary market in which allowances can be traded. In Vermont, proceeds from the RGGI auctions are used to fund thermal energy and process fuel efficiency programs.

There are currently two generating units in Vermont that must comply with RGGI requirements, one owned by Green Mountain Power, the second by the Burlington Electric Department.

The initial RGGI cap of 188 million tons for the years 2009-2011, established during the initial program design period, proved overly conservative. From 2010 through 2012, the allowance price remained at or near the program floor or reserve price.

Exhibit 11-7. Changes in the RGGI Emission Cap, Covered Regional Emissions, and the Average Allowance Auction Price



During the scheduled program review of 2012, the RGGI states agreed to two measures to bring the cap and amount of allowances in circulation into line with actual regional emissions. First, starting in 2014 the annual base cap was reduced by 55% to 91 million tons, just below actual 2012 emissions, and an annual reduction of 2.5% was established. Second, the states agreed to annual adjustments to the base cap to account for the number of allowances still in circulation from the program's earlier years. The RGGI states are planning the next scheduled review of the program in 2016.

Earlier this year (2015), the Analysis Group released a report on the economic benefits of RGGI for the years 2012-2014[243]. The report found that, across the region, the initial $0.98 billion in CO_2 allowance auction proceeds received by the states resulted in $1.3 billion in net economic value. The most cost-effective measure was state investment in energy efficiency programs, with additional contributions

[243] The Analysis Group, *The Economic Impacts of the Regional GHG Initiative on Nine Northeast and Mid-Atlantic States* (2015), www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_july_2015.pdf

realized through measures such as consumer rebates that help recirculate money through the regional economy.

The U.S. EPA announced the Clean Power Plan (CPP) final rule on August 3, 2015. The CPP regulates CO_2 emissions from power plants under section 111(d) of the Clean Air Act, and sets permitted emission levels for power plants for each state. Vermont has no electricity generating units that meet the definition of a regulated entity under the CPP, and therefore has no compliance obligation under this federal rule. However, each of our RGGI state partners does have a compliance obligation, and the CPP has the flexibility (e.g., by allowing multistate compliance) to allow RGGI to be the primary compliance path for these states.

The state will continue to work with our RGGI partners during this program review to maintain and potentially expand opportunities to reduce CO_2 emissions from the electricity-generating sector within the region and beyond. This is appropriate, given that Vermont utilities continue to purchase power from, and share a transmission grid operator in ISO-NE with, states that have CPP obligations. It is important to remain a full and equal participant in RGGI, reflecting our commitment to constructive action along with regional partners.

Recommendations

(1) Continue to participate with RGGI to reduce carbon dioxide emissions from fossil fuel-fired electricity generation.

(2) Vermont should work with other states and provinces in our region, building upon existing regional initiatives such as RGGI, the Transportation Climate Initiative, and the Western Climate Initiative, to investigate and pursue options for market-based GHG policies to integrate with the other approaches described in this CEP, consistent with the principles described in Chapter 4.

11.4 Energy Assurance: Safety, Security, and Resilience

The state must prepare and plan for electric power supply emergencies, as many recent significant weather events, including Tropical Storm Irene and recent ice storms, have reminded us. As the state progresses along the path of strategic electrification identified in this plan, retaining reliable and secure electric supply will become ever more critical. Under the State Emergency Operations Plan, the Department of Public Service (DPS) has the lead role for State Support Function 12 (Energy), which includes electric energy and thermal energy. The causes of widespread power outages in Vermont have historically been severe weather events, such as those involving snow, ice, or wind. If a severe weather event is anticipated, the electric utilities, the telecommunications utilities, and state agencies such as the DPS and the Division of Emergency Management and Homeland Security of the Department of Public Safety participate in daily conference calls to discuss the weather forecast, the status of the electric system (i.e., whether any transmission lines or generation units are out of service for maintenance), and available resources, including plans for additional line crews and associated equipment.

These communications continue during and after the weather event, to discuss the extent of damage and to coordinate the restoration effort. This helps facilitate a statewide coordinated effort to restore electric service as quickly as possible. The DPS staffs the State Emergency Operations Center, to ensure that utilities have a means of coordinating directly with key state agencies to assist with outage restoration. In addition, subsection 248(k) and (l) of Title 30 provide an expedited process for utilities to perform the work necessary to resolve an emergency.

The DPS also assists in state planning for other disruptions in energy supply, such as might involve liquid heating and transportation fuels, as well as non-weather-related risks to electricity (e.g., cybersecurity incidents). Vermont adopted its first Energy Assurance Plan (EAP) in August 2013, on the tenth anniversary of the Northeast blackout of 2003, which affected more than 50 million people (although Vermont was not among them). The EAP is currently included in the State Emergency Operations Plan as an appendix to State Support Function 12. The DPS will update the EAP during approximately the first half of 2016, and this process will involve stakeholder input. A final revision is expected to be completed and released in the third or fourth quarter of 2016.

The EAP defines *energy assurance* 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."

Energy assurance involves an array of activities that fall into three main categories:

- *Planning and preparation* center on identifying key assets and personnel, designing resiliency into critical infrastructure, and creating and updating energy emergency response plans.
- *Training and education* covers the training of government and energy-assurance stakeholders' personnel, as well as conducting exercises that test the effectiveness of the energy assurance response plan.
- *Response activities* include monitoring events that may affect energy supplies, assessing the severity of disruptions, providing situational awareness, coordinating restoration efforts, and tracking recoveries.

Energy assurance includes considering all hazards in the development and implementation of programs and initiatives that address education, training, planning, and execution over short-, medium-, and long-term time horizons for all relevant energy supplies, and for interdependent systems such as transportation and telecommunications.

The EAP addresses natural gas and unregulated heating and transportation fuels along with electricity. It directly addresses interdependencies among fuels, and among systems (e.g., the energy sector's reliance on telecommunications). The EAP is designed to be both a reference and an actionable document, for use in preparing for and responding to an emergency that affects energy availability.

Apart from emergency preparedness, utility planning — e.g., integrated resource plans — must consider energy assurance. This includes preparatory actions that help the power stay on, such as careful vegetation management to clear trees away from power lines, and the strategic location of utility infrastructure to avoid risks in the first place (for example, siting substations and generators outside of floodplains and river corridors), or to make restoration of power easier (as by siting power lines along roadways).

The combined 2013 storm costs for just Vermont Electric Cooperative and Green Mountain Power were $22 million. The magnitude of these costs emphasizes the potential savings from increased effectiveness and lower-cost event assessment, preparation, response, and customer service restoration from weather events that are increasingly frequent and severe. The Vermont Weather Analytics Center Project (VTWAC) is a two-year, highly collaborative $16.6 million undertaking by VELCO (Vermont Electric Power Company) and IBM Research. It builds on previous smart-grid investments by using coupled models and leading-edge analytics to optimize the integration of renewable generation resources, increase grid reliability, and lower weather event-related operational costs.

The VTWAC project is composed of the development of four models: (1) a Vermont-specific version of IBM's Deep Thunder predictive weather model, to produce high-resolution, accurate forecasts up to 48 hours in advance down to 1 km^2, to lower weather event-related costs and increase grid reliability; (2) an advanced electric demand forecast utilizing smart meters, Deep Thunder, and other data sources to better plan for future system reliability needs; (3) generation forecasts for solar, wind, and separately correlated hydro, to improve power-supply planning efficiency; and (4) a coupled model with a probabilistic framework that synthesizes the other models' output to produce actionable information, enabling the optimal balancing of renewable generation, efficiency, demand response, and transmission resources.

The VTWAC's initial application focuses on mitigating transmission constraints to minimize the curtailment of renewable energy. The project's near-, mid-, and long-term benefits focus on improved transmission and distribution grid reliability through earlier, much more accurate weather event information, along with improved balancing of energy supply and demand through increased information on Vermont's intermittent (renewable) generation resources.

When outages do happen, Vermont electric utilities can update a central public website, wwwvtoutages.com. Some have electronic feeds in place to automatically update the site every 15 minutes via their outage management system, while other utilities must log in and manually update outage numbers. The DPS is working with the latter group to increase the number with an automatic feed to the site.

All Vermont electric utilities have log-in access to this website, and are expected to keep it updated to the extent possible. This site shows outages in several formats: a state map that color-codes Vermont counties according to their current number of outages; a list of current outages by utility (and the last time the site was updated by each utility); a matrix showing current outages by utility and county, with totals for utilities, counties, and statewide; and a line graph showing past statewide outages. This site is used by utilities, state officials, the media, and the public to monitor electric outages, especially during emergencies. Some utilities have individual outage web pages on their websites, and www.vtoutages.com links to these.

When provided with appropriate generation and/or storage, portions of the electric grid can be configured to operate independently. These portions are called *microgrids*. As electric circuits around Vermont begin to host more distributed generation, it is becoming increasingly possible to configure storage and enable renewably powered microgrids. There are many other types of microgrids, based on how they are powered, how energy is stored, how loads are controlled or curtailed when in the microgrid state, and whether they generally operate connected to or separate from the statewide grid.

The increasing availability of home electric energy storage, coupled with residential solar PV, could enable neighborhood or community renewable microgrids. Green Mountain Power has installed the state's first fully renewable microgrid in Rutland: the Stafford Hill solar PV generator is coupled with 4 MW of battery storage. In case of a grid failure, the circuit where Stafford Hill is connected can separate from the rest of the grid. This circuit is also home to Rutland High School, which serves as an emergency shelter. In the case of an extended emergency, the solar PV generator could power the shelter indefinitely, without requiring any delivery of fuel except by sunlight.

Recommendations

(1) *The DPS should complete its update of the Energy Assurance Plan in 2016, working with and informing stakeholders to ensure that the state is prepared for the energy components of disasters or other emergency situations.*

(2) *Vermont utilities should harness the capacity of the Weather Analytics Center to increase energy assurance, reliability, and resilience, while more cost-effectively integrating variable renewables.*

(3) *As soon as it is technologically and economically feasible for each utility to do so, it should provide an automatic feed to vtoutages.com.*

(4) *The DPS and utilities should learn from the experience and performance of the Stafford Hill microgrid, and monitor progress in microgrid technology. Where appropriate based on this experience, utilities should facilitate development of microgrids, particularly those that support critical infrastructure.*

11.5 Utility Innovation and Market Participation

The pace of innovation in the electric sector is increasing, especially for distributed energy resources. For instance, solar PV prices have fallen by nearly 60% in the last four years, while the number of electric vehicles in Vermont has increased by more than a factor of 10 and cold-climate air-source heat pumps are rapidly expanding in availability. During the past five years, Vermont utilities have completed deployment of a statewide smart grid, opening the door for modern information technology tools to manage the electric system. Changes wrought by evolving technology will challenge long-held paradigms that underpin utility business models, while also providing opportunities for utilities to increase their own fostering of innovation. Vermont must harness this innovation for ratepayers' benefit and use it to help meet our energy goals, thereby advancing economic, environmental, and health priorities.

Vermont's regulated, vertically integrated electric utilities should become engines of innovation in their service territories. This CEP firmly establishes Vermont as a place where new ideas, technologies, and approaches are welcome. The regulatory environment must also support new ideas. The Energy Transformation (Tier 3) obligation in the Renewable Energy Standard explicitly opens the door for electric utilities to expand their service offerings to the benefit of their customers.

Critically, the RES also establishes an expectation that utilities will meet their Tier 3 obligations in partnership with others, unless the utility is uniquely positioned to provide the service in question (e.g., by using its bill as part of a financing offering). This partnership expectation is critical to ensure that utilities use their role to foster new markets and firms, rather than collect inappropriate additional market power. Partnerships with entrepreneurs, especially, are appropriate.

Engagement by utilities outside their natural monopoly of providing electric energy service means engaging in markets that are competitive. One option is for utilities to form unregulated subsidiaries, which can take on the risk of market engagement while keeping all of the reward. However, the policy driver for such market engagement is to bring aspects of the regulated utility to bear (its customer relationships, its billing system, its access to capital, etc.). Municipal and cooperative utilities also do not have the same opportunity for unregulated activities, so focusing on that structure for implementation could lead to 20% of the state being underserved.

If the regulated utility is going to engage outside its natural monopoly, regulators should maintain institutional skepticism while also seeing the policy need. It is therefore appropriate to consider shaping how utilities engage in these markets to meet otherwise unmet needs, rather than to introduce additional competition. The utility's role should be to drive creation of new markets and transform existing markets. This means only engaging in other markets to the extent it is adding value beyond what existing market participants are already doing. It also means exiting markets as they mature.

Where a utility offers a service that could be provided by another business, it and its regulators should take care to maintain a fair playing field as much as possible. For example, if a utility is offering leasing or tariffed hardware with payment on the electric bill, then it should also offer other participants in that same market access to the utility's bill for repayment, at a fair cost.

The structure of shareholder incentives for for-profit utilities, like Green Mountain Power — such as those incentives embedded in an alternative regulation plan — shapes their market behavior. The continued evolution of these structures should establish shared risk and reward for innovative activities. Under such a structure, shareholders and ratepayers each take some of the financial risk, and each sees rewards when innovative ideas pan out. While it can be challenging to separate activities and their downstream effects into different classes, the regulatory structure should have enough separation between traditional and innovative services that the risk and reward from innovation is not swamped by other risks or rewards from the much larger traditional services.

11.6 Integrated Resource Planning and Distributed Utility Planning

All the recommendations discussed in this plan — from reducing energy demand to facilitating grid interconnection and load management of renewable electricity generation, to encouraging electric vehicle use — affect utility planning. Fortunately, along with the many planning mechanisms described in the CEP, Vermont has specific tools in place to allow for a transparent and open electric resource-planning process by our utilities, through integrated resource plans (IRPs) and other planning efforts. The state must continue to use these activities to advance implementation of the CEP and its recommendations, and of future CEP updates.

Every three years, each of Vermont's regulated electric utilities and the state's natural gas utility must submit for DPS review and PSB approval an integrated resource plan (IRP) that documents the utility's long-term planning efforts (30 V.S.A. § 218c). A key component of each IRP is the utility's planned portfolio of supply resources, demand-side management programs, transmission and distribution improvements, and an associated financial plan that will enable the company to serve its customers at the lowest life-cycle cost, including environmental and economic costs, over the next 20 years (30 V.S.A. § 218c(a)(1)). IRPs must be responsive to the Vermont Electric Plan incorporated into the CEP. The IRP process is also intended to facilitate information exchange among utilities, regulatory agencies, and the public, and to culminate in the filing of utility plans that satisfy the standards for DPS review and PSB approval with a goal of promoting shared understanding, transparent and sound decision making, and effective planning that covers all the utility's operational and financial resources.

The current IRP process is loosely structured, leaving utilities free to interpret the Vermont statute and related prior orders. This has resulted in significant engagement between utilities and the DPS. The IRP process has positioned utilities to explore the full range of energy options and solutions to the benefit of Vermont ratepayers. That said, the IRP process can be better utilized as a way to shape and coordinate the actions of the state's electric utilities; and it provides a clear opportunity for the state to engage the utilities in a continual process of reaching the goals laid out in the CEP.

Related to but distinct from traditional integrated resource planning is *distributed utility planning* (DUP), aimed at creating granular strategies to ensure strategic operation of a utility's distribution system. In brief, DUP encourages utilities to consider all available technologies to meet customer demand in the most efficient and cost-effective way. DUP accounts for strategic siting and operation of modular electric generation and storage technologies, load management, and targeted demand-side management programs, to supplement central station generation plants and the transmission and distribution (T&D) grid for cost-effective customer benefits.

Where IRPs historically focused on questions of utility power supply portfolio construction, including the amount of energy efficiency to obtain, evolution in the Vermont context have shifted IRP toward stronger overlap with DUP. Efficiency acquisition is now the subject of a separate process, the Demand Resource Plans for the state EEUs, and electric portfolios are now much more strongly shaped by the RES requirements. Power supply questions now revolve around the most cost-effective way to meet the RES requirements, not around how much renewable energy to acquire. Meanwhile, Tiers 2 and 3 of the RES require utilities to engage with distributed generation at increasing levels of penetration, along with other kinds of distributed energy resources (such as energy storage and controllable loads) that can be coupled with fossil fuel reduction strategies.

The benefits of distributed utility planning can include reducing the load on T&D systems, deferring the costs of upgrading T&D infrastructure, improving local power quality, and reducing T&D system losses. DUP also potentially offers significant benefits for utilities and their customers, while lowering financial, environmental, and institutional risks. To date, few electric utilities have fully utilized DUP, owing to a number of regulatory and institutional barriers to distributed resource development. These include:

- **Dispersed Benefits**. It is unlikely that the full array of benefits of a distributed resource installation will accrue to the owner of that installation. This could lead to a market failure in which societal resources are allocated inefficiently.
- **Cost Recovery Structures.** Traditional cost-of-service ratemaking, which rewards utilities for prudent capital investments, provides little financial incentive for utilities to lower their investments in T&D. Replacing cost-of-service ratemaking with alternative structure, such as performance-based ratemaking (PBR), has the potential to reward utilities that effectively implement DUP. In principle, PBR rewards utilities for efficient operation and high-quality service, as measured by performance relative to pre-established targets, rather than for capital investments and sales of electricity. Municipal and cooperative utilities should not face this barrier, but they also have few regulatory incentives to engage in more diverse or innovative business models.
- **Planning Methodologies.** Traditional distribution planning methods and models do not account for the various costs and benefits of distributed resources. The data required for a comprehensive assessment of distributed resources in a given area may be undeveloped.

- **Generation Ownership and Integration**. To integrate distributed generation into distribution systems effectively, distribution system planning needs to be closely integrated with generation planning. Such integration is a departure from traditional distribution system planning functions.

Vermont has supported and encouraged the development of DUP. The DPS views it as consistent with Vermont statutes, and with PSB precedents regarding least-cost integrated resource planning for the state's electric utilities. The DPS also regards DUP as consistent with policies promoting the development of renewable energy resources in Vermont. The DPS will continue to work with utilities on DUP in the context of IRPs. Going forward, the DPS plans to collaborate with Vermont's electric utilities, including EEUs, in an effort to build upon, revise, and further specify the best implementation procedures for DUP. This process will seek to develop procedures for reflecting the principles of DUP in integrated resource planning filings by electric utilities.

Appendix B to this CEP provides detailed guidance to distribution utilities for the development of their IRPs. This includes identification of particular content expected in each IRP (e.g., details regarding load forecasts, portfolio considerations, expected transmission and distribution upgrades, and associated financial plans). The IRP requirements established there include a requirement to consider "high-DER" futures. This includes modeling the rapid development of high levels of behind-the-meter generation, storage, and controllable loads as well as significant electrification in the transportation and building heat sectors, and reflects the fact that distributed energy resources and electrification will impact supply, demand, and grid operations.

Recommendations

(1) The state should use the IRP process to work together with the electric utilities to increase the amount of local and renewable energy in their supply portfolios, while maintaining the principles of long-term least-cost integrated planning under the definition set forth in Section 218c(a)(1).

(2) Utilities should expand the IRP framework toward DUP to plan for high DER-penetration futures, and develop better understanding of the costs and benefits of different combinations of DER deployment.

(3) Electric utility IRPs should consider and plan for heat pump and electric vehicle penetration in Vermont, and the effect that the resulting increased electricity consumption will have on their systems.

12 Renewables

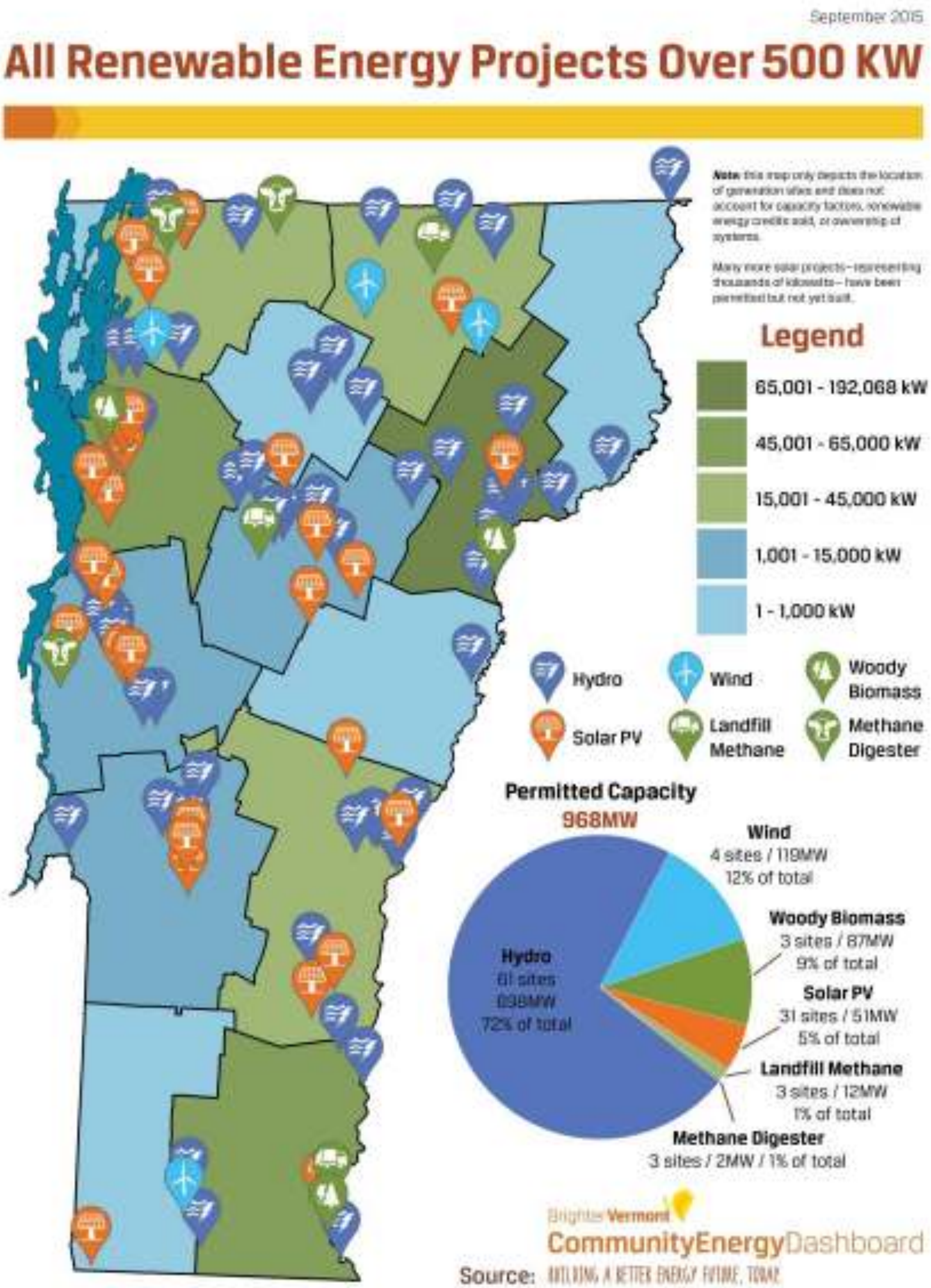
This chapter and Chapter 13 address resources of energy supply that can be used to meet the needs — for heat, mobility, and power —described in the preceding chapters.

End-use energy efficiency is a key resource that can meet demands without the use of any supply resources, often at lower cost and with fewer environmental and health impacts. As such, it is and should remain the first option for meeting energy service demands. But energy efficiency cannot meet all energy needs — so supply resources are required.

This chapter examines these renewable resources:

- Solar,
- Wind,
- Wood and other solid biomass,
- Liquid biofuels,
- Methane from on-farm and non-farm digesters as well as landfills, and
- Hydropower.

Exhibit 12-1. Renewable Energy Projects in Vermont > 500 kW



12.1 Solar Energy

Solar energy is the capture of sunlight to generate power or heat. Solar power production for Vermont, and for locations with similar levels of sunlight, is accomplished primarily with solar photovoltaic (PV) systems, even though other technologies are used to generate solar power. Given that solar PV is the primary technology used in Vermont, this chapter will only cover solar PV in relation to power generation. For solar heating, the chapter will focus on solar thermal collectors used to heat domestic hot water, and will also briefly cover solar space heating and lighting.

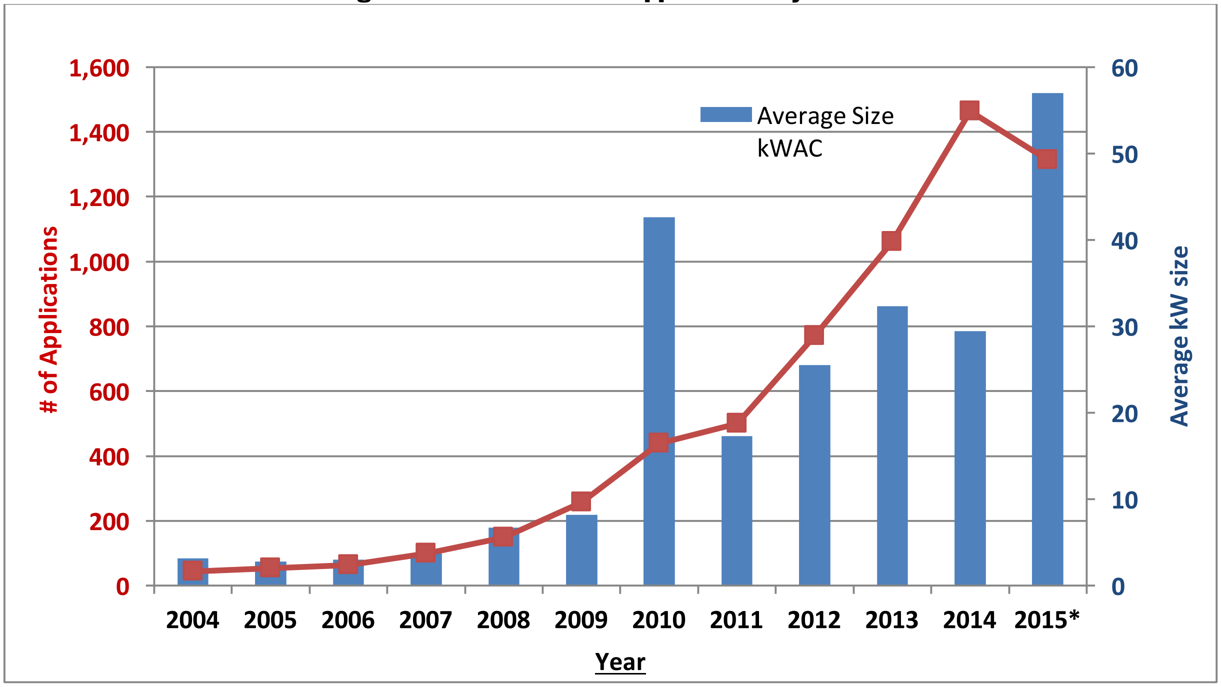
12.1.1 Solar Photovoltaics (PV)

United Church of Thetford, 15 kW solar PV system.

12.1.1.1 State of the Market

Over the past five years, Vermont has seen a tremendous growth in the amount of solar PV deployed across the state. By all measures, the use of solar PV to create power here is on the rise: the number of systems (residential, commercial, and utility-scale), the average size of systems, and the total capacity of systems installed have all increased steeply over the last five years, as shown in Exhibits 12-2 and 12-3.

Exhibit 12-2. Number and Average Size of Solar PV CPG Applications By Year[244]



Incomplete data for 2015 shows that the fast growth in the number of solar PV applications has leveled off, but the increase in the average system size is considerable, and due to several multi-megawatt sized systems proposed in 2015.

This growth has resulted in approximately 200 MW of solar PV either installed or in the permitting process in Vermont[245].

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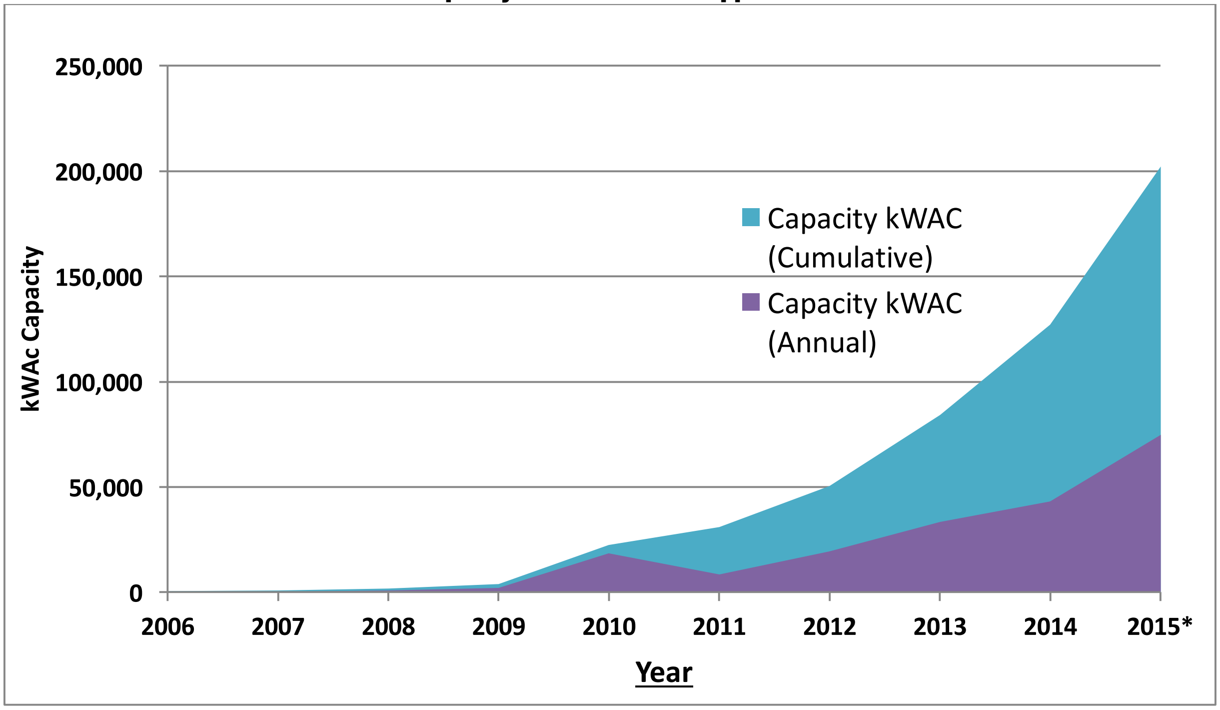
[244] DPS Generator database. *Data is only for first 11 months of 2015.

[245] This does not include the 100 MW of large (20 MW) systems that have applied for interconnection in Vermont.

Exhibit 12-3. Annual and Cumulative Capacity of Solar PV CPG Applications[246]



The efficiency of solar PV panels is also increasing, allowing solar PV to produce more power per square foot than ever before. In the last 10 years, the efficiency of the most common type of solar PV used in Vermont increased from about 12% to 16%. In laboratory tests, the type of solar PV modules most commonly used here reach efficiencies of about 23%[247]. Such laboratory results demonstrate the potential for further increases in solar PV efficiency for systems that will be installed in the near future — which, in turn, will help to reduce the cost of solar PV power.

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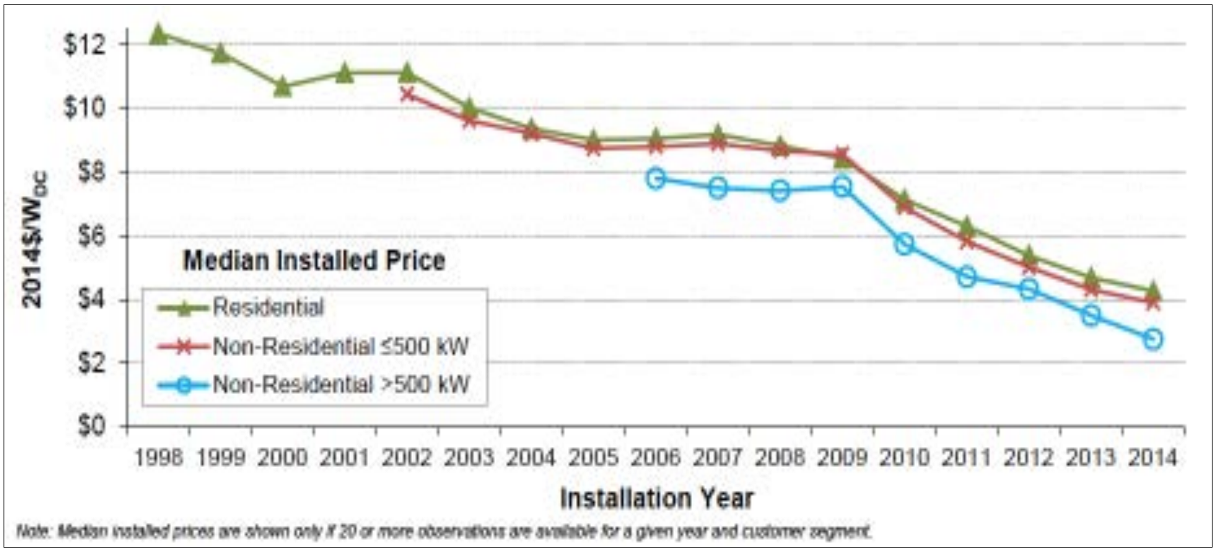
[246] DPS Generator database. *Data is only for first 11 months of 2015.

[247] Dr. Simon Philipps and Werner Warmuth, *Photovoltaics Report* (Fraunhofer Institute for Solar Energy Systems ISE, Freiburg, 2015)

Exhibit 12-4. U.S. National Installed Cost of Solar PV Systems[248]



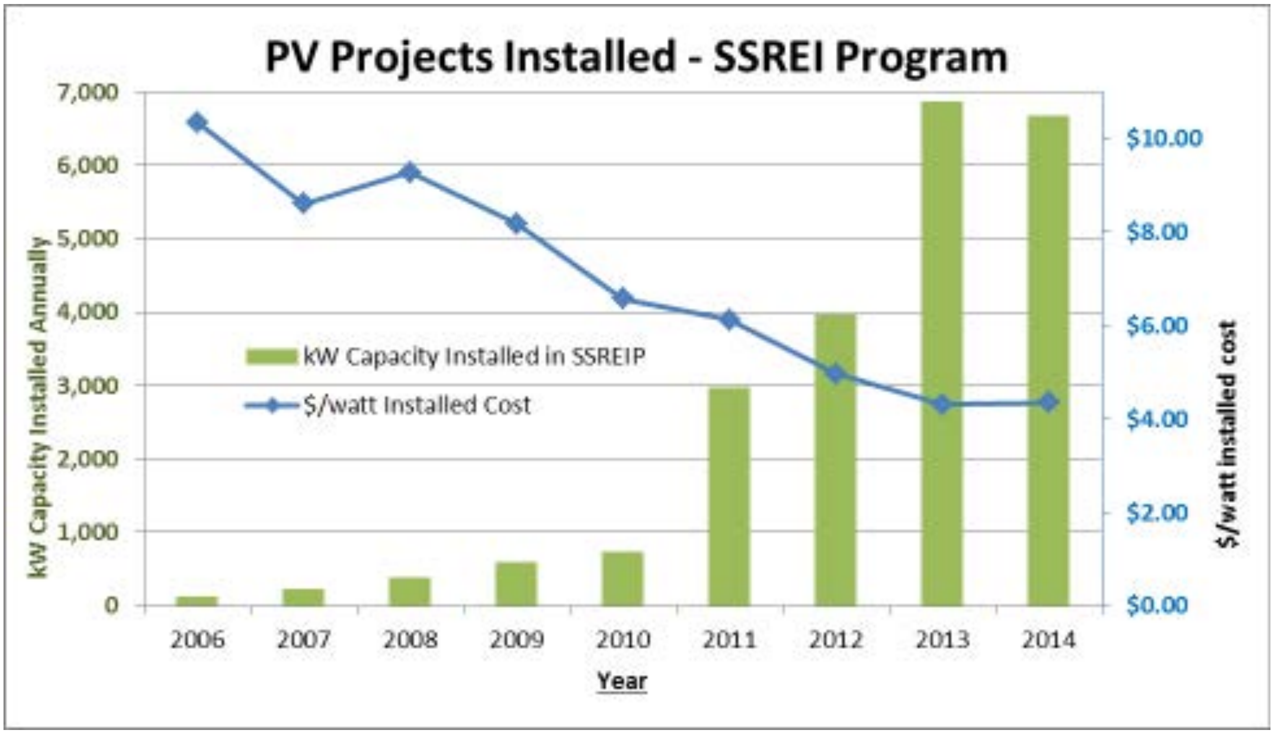
One reason for the increase in solar PV installations is the decrease in solar PV costs. National price data, as shown in Exhibit 12-4, show how the price-per-watt of installed solar PV has declined from over $12/watt in 1998 to just over $4/watt in 2014 for residential systems. Larger commercial systems have installed costs that are even lower, thanks to economies of scale.

The installation costs for residential solar PV systems in Vermont have mirrored the dramatic drop seen nationally. For over 10 years (2004-2014), most residential installations were supported by financial incentives paid through the Clean Energy Development Fund's Small Scale Renewable Energy Incentive (SSREI) Program. The SSREI Program has collected the installed cost data from the almost 4,000 systems that have participated in the program. As Exhibit 12-5 shows, the cost to install solar PV in Vermont dropped by approximately 58% as the annual kW of capacity increased over the last eight years[249].

248 Galen Barbose and Naim Darghouth, *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States* (Lawrence Berkeley National Laboratory, 2015), emp.lbl.gov/sites/all/files/lbnl-188238 presentation_0.pdf

249 Vermont Small-Scale Renewable Energy Incentive Program data, 2006-2014

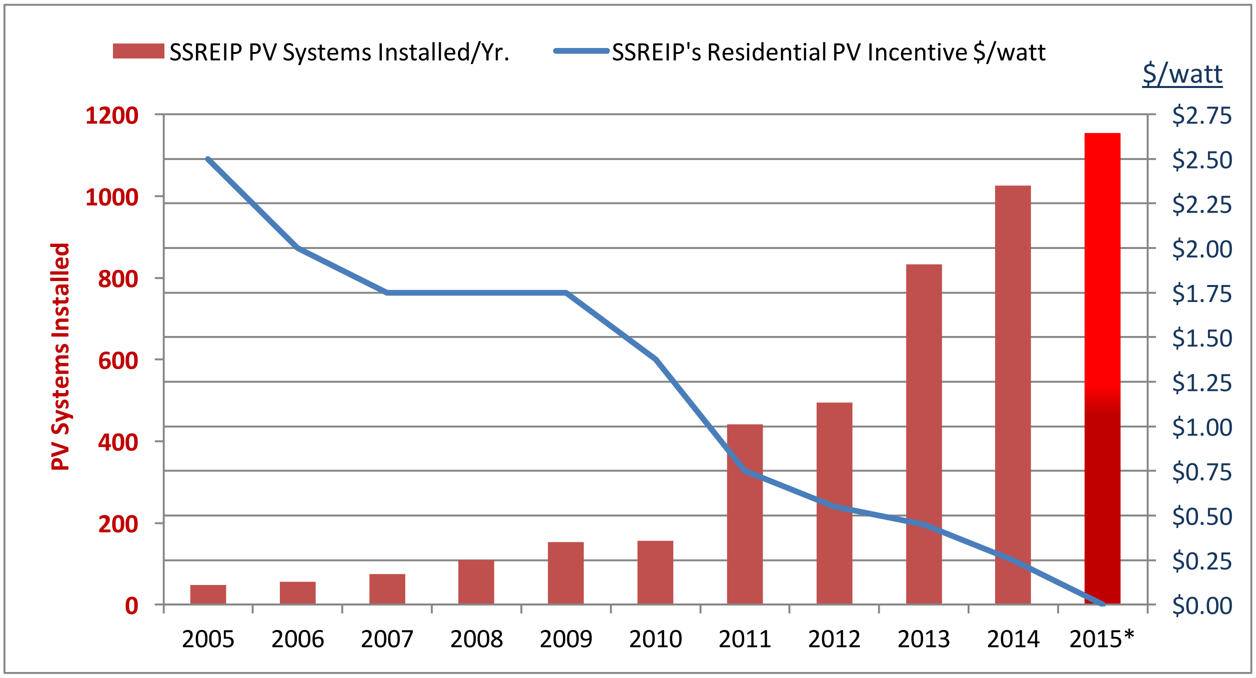
Exhibit 12-5. Cost ($ per kW) and Capacity of Solar PV Systems Installed through the SSREI Program, 2006-2014



Because of the dramatic drop in price and increased market penetration of solar PV, the CEDF regularly lowered the SSREIP incentive level and size of eligible systems. At the end of 2014, the CEDF ended the incentive payment for solar PV systems entirely. This incentive had been in place since 2004, before the CEDF was even created, and was a critical component of the solar PV market in Vermont. The discontinuation of the incentive was consistent with CEDF's plan to decrease and eliminate incentives as the solar PV market matured.

As the Exhibit 12-7 shows, even as incentive payments decreased, the number of solar PV systems incentivized through the SSREIP steadily increased. By 2014, the incentive's value had dropped by a factor of 10, from $2.50/watt in 2004 to $0.25/watt in 2014. The number of CPG applications for projects under 15 kW for the first 11 months of 2015 indicates that there will not be a decrease in the number of residential solar PV systems installed in 2015 compared to 2014, despite the lack of a $/watt incentive.

Exhibit 12-6. SSREI Program Incentive Levels and Number of Solar Photovoltaic Systems Installed[250]



In addition to the SSREI Program, Vermont has supplied incentives to solar PV projects through the CEDF and loan programs, supportive net metering policies, and a business solar tax credit. Solar PV projects also receive federal support from a 30% tax credit and, for commercial systems, an accelerated depreciation schedule.

Many of the solar PV projects installed in Vermont are on farms and other businesses involved in our vibrant farm and food sector. The Farm-to-Plate Network has tracked solar PV installations on farm and food organizations' buildings and land; Exhibit 12-7 shows its findings.

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[250] SSREIP and DPS data. 2015 data includes net metered CPG applications for solar PV systems (of 15 kW or less) that would have been eligible for an SSREIP incentive had such incentives been available in 2015.

Exhibit 12-7. Solar PV in Vermont's Food and Farm Sector[251]

ORGANIZATION TYPE	# OF SITES	SOLAR TYPE	INSTALLED CAPACITY (KW)	% OF TOTAL
Farm	44	Roof	792.9	5.7%
	46	Ground	7,926.4	56.9%
Processing	3	Roof	266.8	1.9%
	4	Ground	590.7	4.2%
Distributor	1	Roof and ground	382.8	2.7%
Retail	12	Roof	323.9	2.3%
	2	Ground	208.4	1.5%
Nutrient Management	1	Ground	2,200	15.8%
Food shelf	1	Roof	14.3	0.1%
Educational Institution	8	Roof	69.2	0.5%
	7	Ground	516.7	3.7%
Support Organization	6	Roof	217.1	1.5%
	1	Ground	399.4	2.9%
		TOTAL	**13,908.5**	**100%**

With the increase in the number of solar PV systems being installed, Vermont's local solar PV industry has also grown. For the past two years, the CEDF has commissioned an industry survey and report on Vermont's clean energy sector. The results of the 2015 study demonstrate that employment in the solar PV sector has increased 21.8% since 2013, with 1,889 solar PV jobs reported[252]. Solar PV has the largest number of jobs in the renewable energy sector: it provides opportunities ranging from manufacturing to sales, design, and installations, and is the fastest growing of all the renewable energy technologies.

The continued growth of the solar PV sector over the last 10 years has helped Vermont achieve top rankings in many national metrics regarding solar PV, and has led to Vermont's reputation as a national leader on policies in support of solar PV development[253]. Vermont's strong support for solar PV — though policies such as renewable energy goals and requirements, and state financial incentives — has combined with national tax incentives, falling solar PV costs, and a greater understanding of the value of solar PV power to create a fertile market for aggressive solar PV growth in the state.

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[251] Data from *Renewable Energy Atlas of Vermont*, in the Energy Plan of the Farm-to-Plate Network (yet to be released).

[252] BW Research Partnership, *Vermont Clean Energy 2015 Industry Report* (for Vt. DPS, 2015), publicservice.vermont.gov/sites/psd/files/Announcements/VCEIR 2015 Final.pdf

[253] Solar Energy Industries Association, *2014 Top Ten Solar* States, www.seia.org/research-resources/2014-top-10-solar-states, and the 2015 U.S. Clean Tech Leadership Index both rank Vermont among the top 10 states.

Even though there has been a tremendous growth in smaller, residential solar PV systems, it is larger commercial systems that are driving the increase in statewide installed kW capacity. Five years ago, Vermont had only one commercial system installed that was over 200 kW in size. Today, more than 100 solar PV systems over 200 kW are either installed or in permitting.

Vermont's Standard Offer Program, which commenced in 2010 and provides fixed long-term contracts for solar PV power, was the initial driving force behind the first larger-sized projects in Vermont (the program has a 2.2 MW facility size limitation). The program has a total cap of 127.5 MW and must contract with a mix of all renewable energy technologies, not just solar PV. In addition, the federal solar tax credit, together with the Vermont investment tax credit, made the economics for all these larger projects favorable enough for developers to take on the capital risks in bringing projects online.

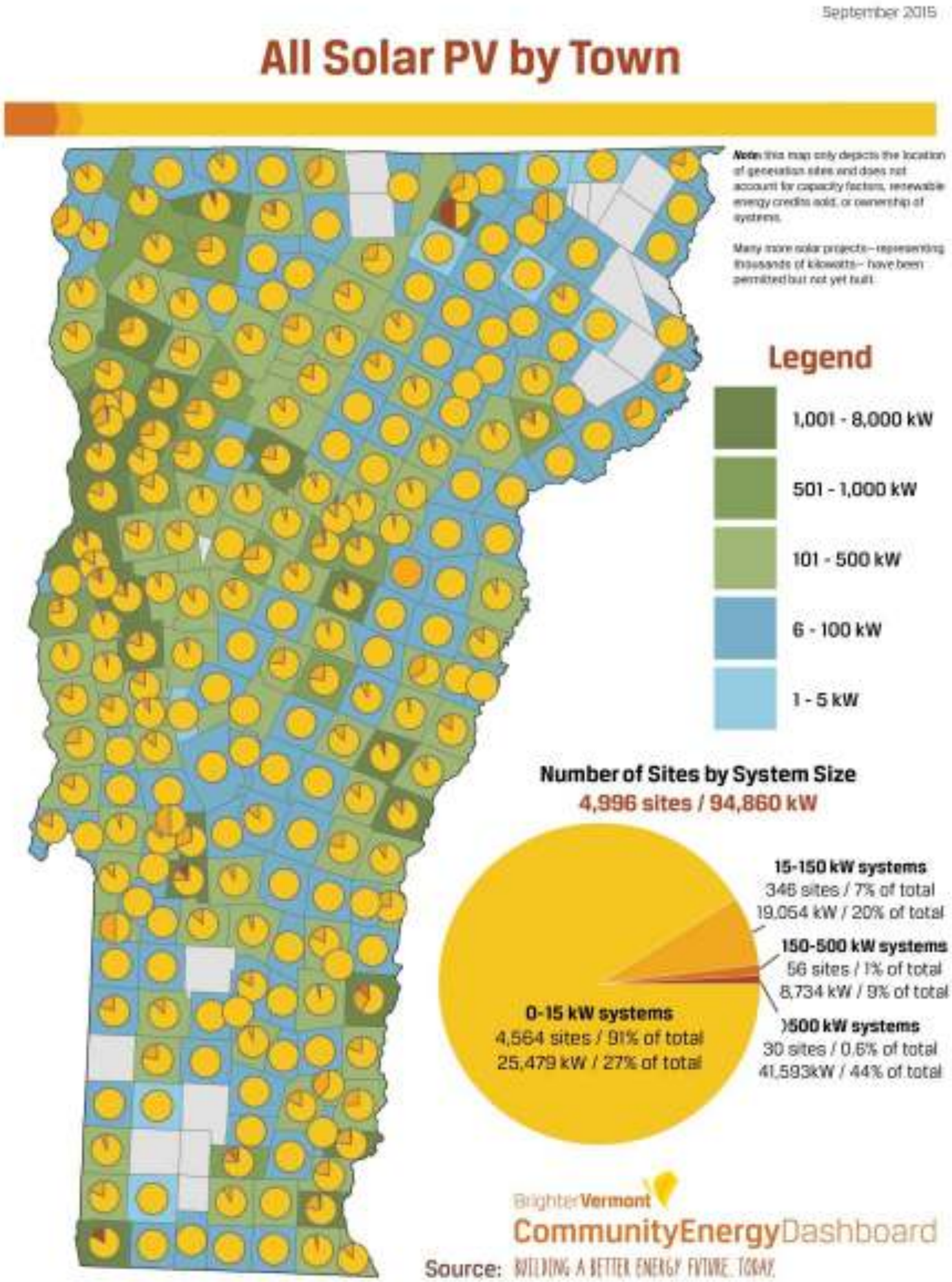
In addition to the commercial projects being built through the Standard Offer and net metering programs, Vermont has seen an increase in utility-owned large solar PV systems. GMP, VEC, BED, and other municipal utilities are all investing in large arrays that will join their power-resource portfolios. GMP has also contracted to purchase power from commercial solar PV projects.

But even though the growth of solar PV has been astounding and PV systems are becoming a common sight across the state, solar PV supplies only a small amount of the state's total electric consumption, accounting for less than 2% of Vermont's total electric usage in 2014[254]. Yet because it often provides power locally during summer peak times, when the demand and price for electricity is high, solar PV provides a disproportionately large benefit to the state's electric utilities. On the other hand, PV requires a large amount of land per unit of energy produced — and the siting of solar PV facilities has raised some concerns about aesthetics and orderly development among some neighbors, adjoining landowners, and municipalities. These issues are discussed in the Challenges and Benefits sections of this chapter.

The Solar PV by Town map (Exhibit 13-8*)* shows the wide distribution of solar PV across Vermont, as well as the relative saturation of solar capacity by town.

[254] DPS data

Exhibit 12-8. Solar Photovoltaic Installations by Town and Size



Future Solar PV Market

To plan for the future development of Vermont's solar PV market, it is not advisable simply to estimate future growth by projecting past growth forward five or 20 years. This plan does assume continued growth in the solar PV market over the next five years, and projects that solar could account for as much as 20% of the state's total energy needs by 2050. The ISO-NE Solar PV Forecast working group has determined that trends indicate an estimated 235 MW of solar PV in Vermont by 2024. That would mean an increase of less than 100 MW from what is now installed, and about 35 MW more than has entered the CPG permitting process to date. This energy plan assumes the level of growth to be a low-growth scenario for solar PV development over the next 10 years.

There is a Vermont study underway examining the requirements and constraints of a faster growth model that would result in 1,000 MW of solar PV installed by 2025. This U.S. Department of Energy's Solar Market Pathways program funded study is being led by the Vermont Energy Investment Corporation. VEIC is engaging stakeholders in an analytic process to help define the needs, barriers, and opportunities for rapid solar PV development in the state. Their objective is to coordinate and facilitate a stakeholder process and develop a stakeholder-informed and supported solar deployment plan for Vermont to reach the 1,000 MW goal by 2025.

The future of the Vermont solar PV market will be shaped significantly by changes Vermont makes to its rules governing net metering. With the federal solar Investment and Residential Tax Credits extended for five more years, how net metering evolves will likely be the most critical policy affecting the PV market over the next five years[255]. The new net metering program rules that take effect in 2017 will be critical in providing market certainty for the value of solar PV net metered projects in Vermont.

Siting and interconnection costs are two other factors that will affect the deployment of PV. As more solar PV projects come online, siting demand may cause viable locations to become more costly, and additional interconnection costs may be required to ensure that the particular electric distribution circuits will be able to reliably handle increased levels of solar PV power. With economies of scale, large systems are the most cost-effective way to install solar PV — but these require large open spaces, close to electric distribution lines that can handle the greater loads. As a result, concerns about the land use and aesthetic impacts of such large systems will need to be addressed as the market matures.

The cost of the solar PV equipment is likely to continue decreasing, but it might not be enough to offset the increased costs of interconnection and siting in the short term.

[255] Federal solar tax credits were due to expire in January 2017, but were preserved until January 2022, with the credit set at the current 30 percent level until January 2020.

12.1.1.2 Resources

Sunlight is Vermont's most abundant energy resource: on average, over 100 million MWh worth of solar energy hits our state every day[256]. If it were possible to convert even a tiny fraction of this solar energy into solar PV power, Vermont could theoretically meet our 90% renewable energy goal with solar power alone. The limiting resource for solar PV is not the fuel; it is the efficiency of the technology — and, as a result, the space required.

Given the efficiency of current solar PV technology, each MW of solar PV needs approximately seven acres of sun-exposed space to produce roughly 1,200 MWh over a year's time[257]. The Challenges section of this chapter discusses the factors that may limit the locations where solar PV can be sited (solar access, aesthetics, environmental concerns, electric system stability), and the amount of land that needs to be found for solar PV to meet the CEP's 90% goal.

12.1.1.3 Siting and Permitting

The dramatic increase in solar PV development has led some communities and Vermonters to question how much control local communities should have over the permitting of solar PV, and whether the current permitting process is adequate to protect communities and adjoining landowners while ensuring the appropriate treatment of ecologically sensitive areas and the conservation of agriculturally productive land.

In response to these concerns, the Legislature in 2015 created a Solar Siting Task Force to investigate the siting and permitting of solar PV, and to produce draft legislation for the 2016 legislative session. As of the drafting of this CEP, the Solar Siting Task Force had not completed its work. This Task Force has considered the cumulative impacts of solar PV development, the challenges to the siting process resulting from the scale and pace of solar PV deployment, and various options for municipal and regional planning to meaningfully inform the siting process. It is considering both regulatory and programmatic solutions. The Task Force is expected to produce its final report by January 2016, and the Legislature is expected to consider their suggestions in the coming session.

Permitting for all solar PV systems resides with PSB, with input and requirements (depending on the details of a proposed project) provided by the Agency of Natural Resources, Agency of Agriculture, Division of Historic Preservation, and the DPS. In addition, municipalities, abutters, and others can participate in the PSB permitting process.

In the 2015 legislative session, Act 56 gave communities more leverage in the siting process by giving host municipalities the right to appear as parties in the Section 248 process, establishing statewide minimum

[256] NREL National Solar Radiation Database (TMY2) data sets for Burlington.

[257] Assuming a 14% capacity factor.

setbacks for solar PV systems over 15 kW, and allowing municipalities to enact and apply screening ordinances to solar facilities in the context of a Section 248 proceeding.

Solar PV is not as dense, power-wise, as other energy sources: it requires a relatively larger amount of space to produce an equal amount of power. Solar PV also has specific siting needs with respect to access to sunlight and interconnection with the power grid. Residential and smaller commercial systems can be installed on the roofs of existing structures with good solar access, and no special consideration of the distribution interconnection is normally required. In contrast, larger commercial and utility-scale systems must be located in areas of the distribution system that are served by three-phase lines; and engineering analysis is often required to ensure that the system can supply power without compromising the reliability of the electric grid.

The local distribution utility addresses interconnection issues in response to an interconnection application filed by the project developer. The interconnection agreement reached between the utility and the developer is incorporated into the Certificate of Public Good, if one is granted to the project.

Pursuant to Vermont's statutory net metering system-size limit of 500 kW, commercial systems seeking to take advantage of this program are often designed for a capacity of just under 500 kW. There are also many commercial projects installed with just under 150 kW of capacity, to take advantage of the streamlined approval process available to projects under that size.

The PSB, through its Rule 5.100, has established expedited permitting pathways for solar PV systems under 150 kW and systems under 500 kW. These variations of the Section 248 review process conditionally waive certain statutory criteria, and provide a short window — between 10 and 30 days once a petition or application is filed with the PSB — for the submission of comments to the PSB on concerns and issues raised by the project, or to request a hearing. Some citizens and municipalities have found it difficult to engage effectively in the review of solar PV projects, given the expedited timelines and the court-like permitting process.

Act 99 of 2014 directed the PSB to convene a process to create new net metering and interconnection rules. The process is still underway; the PSB recently released draft rules for comment. In its initial comments to the Board, the DPS proposed as part of its rate structure construct that rooftop projects and those sited on parcels with reduced economic or environmental potential receive additional credit, in order to level the playing field between these typically more challenging sites and those that are easier to develop, such as greenfields.[258]

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258 psb.vermont.gov/sites/psb/files/20150612%20Act%2099%20Workshop%20Comments%20of%20the%20Department%20of%20Public%20Service.pdf

12.1.1.4 Benefits

Solar PV power has several distinct benefits that make it a power source the state should continue to support.

As a non-emitting power generator, solar PV has similar benefits to other renewable energy generation in that it can supplant power generated by polluting power sources, such as those using fossil fuels. As a result, an increase in solar PV generation can lower GHG emissions attributed to Vermont's electric power consumption. Solar PV can also be located close to homes and communities without concerns about pollutants that are hazardous to human health, such as particulate matter, nitrous and sulfur oxides, ground-level ozone, and carbon monoxide.

Solar PV also has electric-system benefits, due to the time and location of its power production. Solar PV is largely a peak electric load-following resource — meaning that during peak summer loads, solar PV systems are at near their highest production, resulting in cost savings to the utility and providing reliability benefits to the grid.

Solar PV can also be extremely distributed, meaning it can produce power throughout the electric distribution system close to the houses and businesses where the electricity is used. This distributed nature of solar PV lowers line losses for the utility, as less power needs to be transported through its lines, adding another element of cost savings.

In addition, solar PV power is generated without a significant amount of noise and requires only low levels of maintenance.

Solar PV provides utilities with increased diversity and grid resiliency. A fleet of small solar PV generators limits the financial and technical risks of relying too heavily on any one power technology or facility.

While solar PV's power-generation curve pairs well with the majority of the state's power-demand curve, this is not the case for all Vermont's utilities. Some, for example, have peak power demands after dark—and in cases like those, this one benefit could become a challenge.

12.1.1.5 Challenges

Changing Time of Peak Demand

As more solar PV power is installed in Vermont and regionally, the increased solar PV power production will shift the daytime peak further toward sundown, thereby diminishing the peak-cost advantage of solar PV. One response will be to encourage more west-facing panels (instead of south-facing panels), to maximize late afternoon production when electricity prices are highest. Under existing net metering rules, all kWh produced are valued the same, regardless of when they occur — and a south-facing array produces the greatest number of kWh. New net metering rules currently being crafted by the PSB could value energy from solar PV systems differently, depending on time of day.

Solar PV is not likely to be able to contribute to reducing energy demand during winter peaking periods. While the demand during winter peaks across New England is not as large as summer peak demands, limited natural gas supplies during cold temperatures can create energy demand peaks that result in very high peak prices for Vermont utilities at times when solar PV production is low or nonexistent.

Land Use

Solar PV requires adequate access to both sunlight and electric distribution lines that can take the power produced. These requirements often lead project developers to select sites that end up being quite visible — such as in open fields next to roads. Some individuals, adjoining landowners, and communities have raised concerns about the aesthetic and farmland impact of selecting such sites, especially in areas where several commercial and utility-scale solar PV systems are located in close proximity. Siting solar PV on agricultural land, near roads and other highly visible locations, and in the midst of residential communities will likely become more of a challenge as more of these types of solar PV projects are built.

For Vermont to get a significant amount of its power from solar PV while avoiding the most contentious land use debates, the state will need to maximize the installation of solar PV on rooftops, and on land without significant natural resources or that has already been removed from the working landscape — for example parking lots, reclaimed gravel pits, and capped landfills.

To maximize the use of roofs and other already developed areas for solar PV development, Vermont will need to provide incentives and other means of accomplishing its goal at the lowest possible cost to ratepayers. For example, a higher net metering tariff could be provided for roof-mounted solar PV, and for solar PV in areas such as parking lots.

Under current net metering rules, customers can reduce their annual bill to zero; but if a net metering customer generates more power than they use in a year, they receive no payment for this net excess generation. Customers therefore install solar PV systems on their roofs based on their power consumption and not the size of their roofs, leaving part of the roof empty. Tariffs that go beyond net metering could allow customers to monetize any net excess power produced, as an incentive for solar PV systems to be designed based on roof size.

Group net metering is one way to maximize good use of solar on roofs under the current net metering rules, but it is complicated and burdensome for the average residential customer. Allowing customers to lease their roof space to their host utility, and/or to get paid for excess power, would make it simpler for many customers who have good solar roofs but do not want to invest in a solar system. Utility- or third-party ownership and payment will provide them with an incentive to support increased solar PV generation.

While the state should be careful to not strengthen the utilities' monopoly to the detriment of Vermont's vibrant solar energy business sector, there is value in having the utility involved in residential rooftop systems as a way to maximize use of such sites. Even without the utility owning rooftop solar PV, such systems could be part of a rooftop solar PV tariff that requires the power to be purchased by the utility in situations where group net metering is not desirable.

Utility-owned rooftop solar PV could also provide more publically available data: it could serve as a type of research and development program that customers would not want to fund on their own, but would be willing to host if compensated.

The amount of solar PV that could be installed on large commercial rooftops, multifamily housing rooftops, parking lots, and closed landfills has not been calculated. The state should estimate the technical potential for solar PV on these sites, as well as the costs and benefits of installing solar PV. Such analysis would help inform policy decisions on how to encourage such sites. The state could also explore mechanisms to require that, where practical, all new commercial, multifamily housing, and parking lot construction be equipped with solar PV.

The CEP lays out a course designed to result in Vermont obtaining 90% of its total energy needs from renewable energy. As is discussed in Chapter 11, the amount of energy Vermont will need to get from each renewable technology to reach the 90% goal varies depending on what is installed over the next 35 years. Vermont currently has approximately 200 MW[259] of solar PV installed or in the permitting process.

Chapter 11 lays out different scenarios for the amount of solar PV that Vermont might have in 2050. This amount ranges between 1,500 and 2,250 MW of solar PV —roughly eight to 12 times the current amount of solar PV installed or in permitting. To reach the 1,500 MW level, Vermont will need to install an average of roughly 38 MW of solar PV each year for the next 35 years. It is reasonable to assume that the solar PV needed will be overwhelmingly located within the state's boundaries.

If Vermont maximizes the use of the residential roofs for the increased deployment of solar PV, approximately 350 MW could be sited on residential roofs. That would require approximately 25% of all homes, with an average of 5 kW on each roof — which is challenging, due to the increased costs and lower power production of many small roof-mounted systems compared to larger ground-mounted systems.

As the amount of installed solar PV grows, the land use and grid-reliability challenges become more pronounced. It will be a challenge to find sites that have good solar access and can meet the aesthetic, environmental, and grid stability challenges for all this new generation. To the extent that land can be used for solar PV installations and additional purposes, including recreation, agriculture, and parking, it diminishes the potential for conflict between single-use choices.

While the efficiency of solar PV is going up, requiring less space per/kWh generated, the solar arrays being installed will degrade over time (kWh output will decrease about 0.5% to 1% a year), creating a need to either re-power existing plants or to find locations for new solar PV just to keep solar generation constant. To keep the power produced from solar PV constant for each 100 MW of solar PV installed, 0.5 to 1 MW of new solar PV must be installed annually, or re-powered at existing sites.

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259 About 120 MW installed and an additional 80 MW that has started the permitting process.

In addition, while most solar PV projects assume a 20-30 year operating life for the purposes of permitting, it will likely be necessary to re-power existing facilities after 30 years, and to continue energy generation in those locations if the state is to maintain the levels of in-state renewable generation needed to achieve the 90% by 2050 goal.

The land use challenges as well as the intermittent nature of solar PV are issues that other states and countries have faced. Germany has largely dealt with these challenges to the point where, in 2014, 7% of its electricity is provided by solar PV: a total of 38,000 MW spread over 1.5 million solar PV systems[260]. An equivalent amount of solar PV per square mile in Vermont would be approximately 2,600 MW[261]. That is 350 MW more than the high solar PV scenario for Vermont's 2050 energy portfolio presented in Chapter 11. To match Germany's 7%, Vermont would need about 350 MW of solar PV.

To clarify the eligibility of solar PV projects in Vermont's Current Use program, the Vermont Tax Department created a technical bulletin[262] that explains the criteria and their statutory basis. One notable criterion: a facility may be part of a farming operation (and thus eligible for the program) if half or more of the electricity is used by farm buildings that are enrolled in the program.

Price

The price of solar PV as compared to fossil fuel-based market power has long been a challenge for solar PV. Solar PV prices remain above current market power, which is at historic lows due to low natural gas prices (gas is the fuel largely responsible for setting power prices in the New England power region). Yet solar PV's price, once seen as its primary problem, is becoming less of a concern every year as these prices decrease and as solar PV power is valued compared to the power it displaces during the day; and as its ancillary benefits (long-term stable price, forward capacity credits, peak shaving) and environmental benefits are fully valued.

Firefighting

Roofs covered with solar PV systems present a new challenge for Vermont firefighters, who often need to cut holes in roofs of structures with an active fire. New training and awareness are required on how best to access a roof with a solar PV system, and how to remove the solar PV panels or parts of the electric system while preventing electric shock to firefighters. Solar installers should be aware of the latest fire safety codes as they relate to solar PV and structures.

Grid Disconnection

Many of the benefits of solar PV rely on it being connected to the grid — but if the price of solar PV and power storage continue to decline, customers currently interconnected to the electric grid could decide to disconnect. There is a danger in policies or trends that would cause or encourage customers to

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[260] Dr. Simon Philipps and Werner Warmuth, *Photovoltaics Report* (Fraunhofer Institute for Solar Energy Systems ISE, Freiburg, 2015)

[261] Vermont has only about 7% as much land area as Germany.

[262] Vermont Dept. of Taxes, *Solar Generating Facilities Constructed on Land Enrolled in the Current Use Program* (Technical Bulletin 69, 2015), tax.vermont.gov/sites/tax/files/documents/TB69.pdf

disconnect, or to act in other ways that do not support a modern electric grid that is over 90% renewable and highly reliable. The state should work to avoid policies that result in customers with the most means disconnecting from the grid, and leaving those who lack the means to disconnect to pay for the maintenance and renewable energy improvements to the electric portfolio.

The state and the electric utilities should establish programs that encourage customers to think of themselves as part of an interconnected energy system made up of their neighbors and fellow Vermonters, and to act in ways that are beneficial for the whole system.

Strategies and Recommendations

Strategy 1: Encourage utility and commercial solar PV projects without allowing such projects to limit residential solar PV installations.

Recommendations

(1) Establish new 2017 net metering rules that provide interconnection, application, and generation credit for systems that preserve viable residential access to solar PV installations.

(2) Maximize electric grid information, including circuit-level data of the distribution grid, to facilitate siting of projects that will maximize the benefits of solar PV as well as to deter projects that will not be able to interconnect cost effectively.

Strategy 2: Increase and maximize the number of solar PV systems sited on the built environment.

Recommendations

(1) Structure utility regulations and net metering rules, policies, and incentive programs to promote installation of solar PV projects where there is electric demand, and on locations where the land has already been built impacted (e.g. roofs, parking lots, landfills).

(2) Facilitate the statewide collection of aerial photographs or LiDAR images of high-population areas, and make them publicly available to allow for better remote site assessments of the amount of solar PV that could be built on existing roofs, parking lots, and other such spaces.

(3) Establish tariffs within or outside of net metering rules that allow utilities and/or commercial third parties to install solar PV on their customers' roofs, or pay for excess power produced from roof systems, as a way to maximize the use of well-sited roofs for solar PV.

(4) Continue to support updates to building standards and energy codes that promote solar PV for new construction and major renovations.

Strategy 3: Increase the amount of solar PV generation in Vermont's power portfolio.

Recommendations

(1) *Encourage the development of locally controlled solar PV projects as a way to strengthen community support for otherwise challenging siting projects.*

(2) *Encourage utilities to offer customers the option of making solar PV loan payments on their utility bills.*

(3) *Complete the revisions to the PSB's interconnection rules (Rules 5.100 and 5.500) with an effort to make the interconnection application process as predictable and timely as possible for solar PV systems. The interconnection process should be designed in a way to allow it to evolve and allow for flexibility as solar PV and inverter technologies change and solar PV penetration reaches critical levels.*

(4) *The state should continue to install solar PV systems on state buildings, and should use solar PV systems coupled with battery storage for remote power needs where appropriate.*

(5) *Create, partnering with the UVM Extension and farmers, basic guidance for grazing sheep within and around conventionally installed, ground-mounted solar arrays, and guidance for other agricultural uses or ecological system services that can occur within a conventionally installed, ground-mounted solar array.*

***Strategy 3: Increase the safety of PV systems*.**

Recommendations

(1) *Provide firefighters with basic training in fighting fires on structures that have solar PV installed.*

(2) *Provide training to Vermont solar PV installers on the latest fire and electric safety codes, to increase safety and help to secure solar PV generation.*

***Strategy 4: Improve the solar PV permitting process*.**

Recommendations

(1) *The state should evaluate the impact of the solar siting reforms contained in Act 56 of 2015, and consider the recommendations to be made by the Solar Siting Task Force.*

(2) *Protect, through the Section 248 process, farmland and especially primary agricultural (USDA NRCS-rated) soils, as defined by statute, by requiring that developers: attempt to avoid soils rated USDA NRCS 1-7 and/or actively farmed soils; do not remove from or-scrape or grade-soils on farmland sites; design sites to avoid restricting or preventing access to USDA NRCS-rated soils that are separate from the site itself; and decommission all infrastructure at the end of the its useful life.*

(3) *Establish construction practices for roads and other practices that facilitate low-cost decommissioning and effective soil reclamation.*

(4) *Ensure, through PSB rule, that towns, neighbors, and parties have sufficient opportunity and time to comment effectively on solar PV CPG petitions and the larger net metering applications.*

12.1.2 Solar Thermal

Although Vermont's weather limits the amount of available solar energy in comparison with sunnier locations, there is enough sunlight to warrant installing solar thermal energy systems in Vermont.

The sun's warmth and light can be captured passively though south-facing windows in our homes and businesses. Architecture that emphasizes southern exposure can help provide light and warmth. In addition to passive collection of sunlight, active collection is possible. Active systems use solar energy collectors, pumps, and heat exchangers to maximize the capture and use of solar thermal energy.

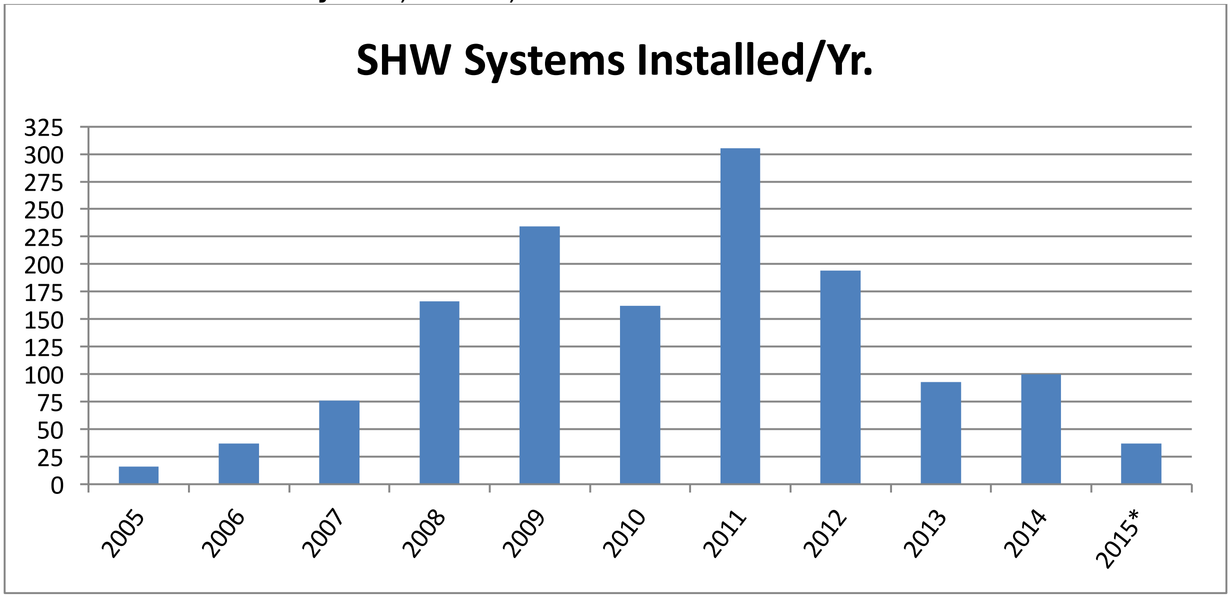
At Vermont's northern latitude, most of our annual sunlight is available in the summer, when space heating is not required but we still need heat for water. As a result, solar thermal energy generation in Vermont is best suited for heating hot water with an active solar system. A properly sited and designed solar hot water system in Vermont can supply 60% to 70% of the annual thermal energy needed for domestic hot water usage. By reducing the amount of heating fuel or electricity needed, such a system can provide a reasonable rate of return[263] on its cost. Solar hot water systems use relatively simple technology, and the equipment can and has been manufactured or assembled in Vermont.

The Vermont SSREI Program has provided incentives for solar hot water (SHW) systems since 2004. As the Exhibit 12-9 shows, there has been a significant decrease in the installation of solar hot water systems in the state. This is likely attributed to several factors:

1. *Price:* The installed costs of SHW systems have remained constant, and have even increased slightly since 2009. The price difference between solar PV and SHW used to be an advantage for SHW; but as solar PV prices have fallen dramatically and incentives have been added for solar PV that are not available to SHW (i.e., net metering credits), the advantage has started to shift to solar PV. This has led some Vermonters to choose solar PV over SHW systems, even though they are not mutually exclusive.
2. *Complexity:* While SHW systems are relatively simple, they can involve complex plumbing that requires regular maintenance. This has been an issue of concern for installers and customers.
3. *Competition:* The availability and marketing of solar PV coupled with high-efficiency heat pump electric water heaters (sometimes offered with leasing and other financing products) can make a solar PV-powered hot water heater an easier and more cost effective purchase than a SHW system.

[263] John Richter, *Financial Analysis of Residential PV and Solar Water Heating Systems* (2009), www.mich.gov/documents/dleg/Thesisforweb_283277_7.pdf

Exhibit 12-9. Solar Thermal Systems, Vermont, 2004-2014[264]



Solar Space Heating

Given the low amount of usable sunlight in the winter when space-heating needs are greatest, solar energy may not be able to contribute a significant amount toward meeting Vermont's space heating needs. There are some applications in which solar heating could be recommended, if they — particularly their heat-storage components — are designed well. With improvements to thermal storage technologies, solar space heating could become more prevalent in Vermont.

Active solar air heating systems can be a simple application of solar energy, because they have no storage mechanism or interconnection to other systems and can provide heat without the heat-loss properties of windows. Solar air heating systems can be used for either supplemental space heating or to preheat ventilation air. However, solar air heating systems do require space on the southern side of buildings, where there is often a greater desire for windows.

Recommendations

(1) Lead by example by having the state install solar thermal systems on buildings where practical.

(2) Consider building code requirements that passive solar design and siting principles be incorporated into new buildings that have a large hot water load (i.e. laundromats, hotels).

(3) Evaluate Vermont's solar thermal installations and recommend strategies to encourage specific, targeted, high-value uses of active solar thermal energy systems.

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264 Vermont Small Scale Renewable Energy Incentive Program, 2015 data for first 11 months only.

(4) *Develop a growth strategy for the solar thermal sector that recognizes the specific barriers and opportunities for solar thermal in Vermont.*

(5) *Support the creation of financing products that encourage more SHW installations. For example, electric utilities and Vermont Gas could offer on-bill financing of SHW systems.*

(6) *Ensure that solar thermal applications are eligible for the energy transformation tier of the Renewable Energy Standard.*

12.1.3 Solar Lighting

Daylighting is the use of sunlight to brighten our homes and buildings. Proper use of daylighting can reduce the electricity used during the day for lighting, and it provides what most consider a more pleasant space in which to live and work. For these reasons, daylighting should be encouraged.

At the same time, daylighting has energy tradeoffs that should be considered. Where there is a window or skylight letting in daylight, there is more heat leaving the building, compared to the wall or celling without the window; this results in increased energy use. Also, improperly designed homes and businesses can have problems with too much sunlight entering the building, causing an increased use of energy as the occupants turn to air conditioning and/or cooling fans.

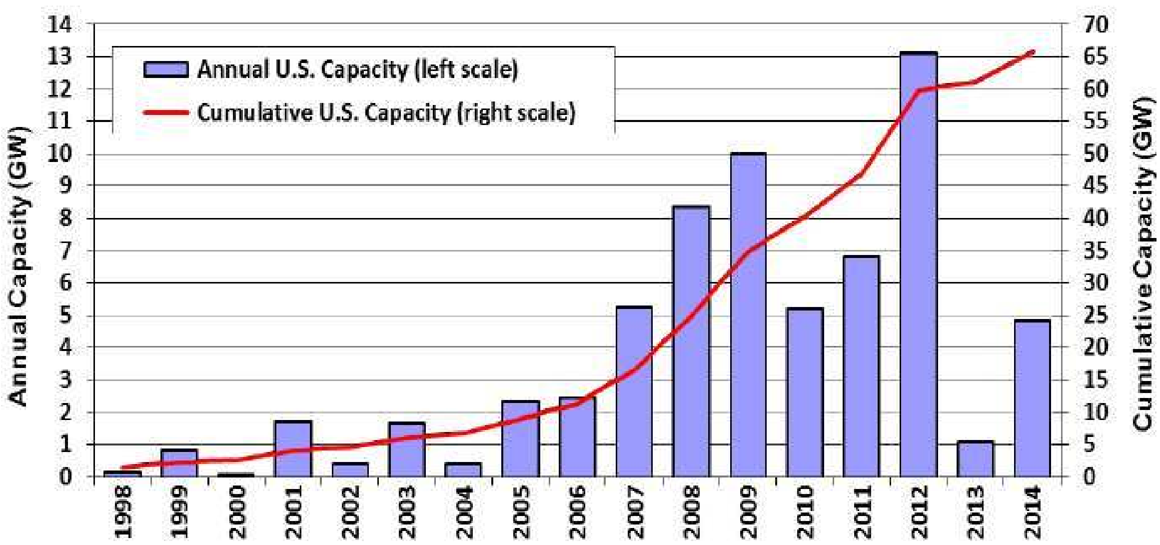
As lighting has become more efficient, the energy savings from daylighting has decreased. At the same time, the understanding of thermal envelopes and the loss of energy from daylighting techniques (skylights and windows) has increased. This has led to less interest in daylighting as an energy-saving measure, and more interest in it as a quality-of-life enhancer.

12.2 Wind Energy

12.2.1 Overview

Wind energy provided 4.4% of the nation's electricity during 2014, and delivered 28% of all new capacity installed over the past five years.[265] The U.S. ranked third in the world in annual wind power capacity additions in 2014, and second in cumulative capacity installed through the end of 2014, at 65,877 MW (see Exhibit 12-10).[266] However, we lag behind over a dozen other countries (most in Europe) in terms of wind capacity as a percentage of total electricity generated.[267]

Exhibit 12-10. U.S. Wind Power Installed Capacity[268]



In Vermont, about 6%[269] of our electric power is currently sourced from wind energy generated in-state, primarily from the large wind facilities in Searsburg, Sheffield, Lowell, and Georgia/Milton, which together account for 119 MW of installed capacity and over 300 GWh[270] of annual production. Vermont imports an additional 200 GWh of wind energy from facilities in Maine and New Hampshire, bringing the total contribution of wind energy in our electric portfolio to approximately 9.5%. As discussed in Chapters 4 and 11, utilities currently sell the RECs associated with existing wind projects. Utilities can

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265 American Wind Energy Association, *U.S. Wind Industry Annual Market Report Year Ending 2014*, www.awea.org/AMR2014

266 U.S. EERE, *2014 Wind Technologies Market Report*, emp.lbl.gov/sites/all/files/lbnl-188167.pdf

267 Ibid

268 Ibid

269 Based on total sales, which are lower than power acquisitions because of distribution losses.

270 EIA and DPS data

only claim particular power resources in their portfolio are renewable to the extent that they retain commensurate RECs.

12.2.2 State of the Market

Wind power production is considered a complement to solar output in a renewable portfolio, on both a daily and a seasonal basis. For example, during Vermont's winter when sunlight is at its weakest, average wind speeds measure at their annual high. Wind power is intermittent in nature, like some other renewable sources of power; thus, resource planning is required for effective grid integration. In the last decade, wind resource forecasting has emerged as a primary mechanism for effectively managing wind resource variability, and is in use by plant operators in addition to utilities and the regional grid operator, ISO-NE, which in 2013 incorporated wind forecasting into its daily system operations.[271]

Vermont can add additional wind power to its portfolio in several ways: purchases from out-of-state wind projects (including offshore wind), purchases from in-state wind projects (through the Standard Offer program in addition to power purchase agreements by utilities and PURPA 4.100 contracts), and interconnection of additional small-scale, net metered installations that serve homes, businesses, and communities.[272] In aggregate, net metered wind projects in Vermont amount to just shy of 2 MW, while wind projects recently approved under Vermont's Standard Offer Program amount to about 700 kW. When added to the 119 MW of capacity at Vermont's four large-scale wind farms, the total installed capacity of wind permitted in the state equals approximately 122 MW (see Exhibit 12-11).

Regardless of Vermont's own wind power development, it is clear from the projects in development regionally that wind energy will be a growing source of electric supply in the regional markets.

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[271] "New Wind Power Forecast Integrated into ISO-NE Processes and Control Room Operations" (ISO Newswire, 2014), isonewswire.com/updates/2014/4/1/new-wind-power-forecast-integrated-into-iso-ne-processes-and.html

[272] In Vermont, wind facilities rated at no more than 100 kW are considered small-scale. Those rated up to 500 kW can be net metered. Larger facilities are classified as commercial or large-scale.

Exhibit 12-11. Wind Projects in Vermont's Electric Portfolio[273]

Scale	Project	Developer/Owner	Location	Turbines	Turbine Capacity	Project Capacity	Status
Utility Scale, In VT	Searsburg	Green Mountain Power	Searsburg	11	.55 MW	6 MW	Operating
	Deerfield	Iberdrola	Searsburg & Readsboro	15	2 MW	30 MW	Permitted
	Georgia Mountain Community Wind Project	Georgia Mountain Community Wind, LLC	Milton and Georgia	4	2.5 MW	10 MW	Operating
	Kingdom Community Wind	Green Mountain Power	Lowell	21	3.0 MW	63 MW	Operating
	First Wind Sheffield	SunEdison	Sheffield	16	2.5 MW	40 MW	Operating
Utility Scale, Out of State						**Capacity Sold to VT**	
	Granite Reliable Power Windpark	Nobel Environmental Power	Coos County, NH			82 MW	Operating
	Saddleback Wind	Patriot Renewables	Carthage, ME			7 MW	Operating
	Hancock Wind	SunEdison	Hancock County, ME			13.5 MW	Under Construction
Small Community				**# Sites**	**Avg kW**		
	Net metered[274]	Various	Various	188	10 kW	1.9 MW	Permitted
	Standard Offer	Various	Various	8	81.5 kW	652 kW	Approved contracts

12.2.3 In-State Resources

Vermont's higher elevations provide considerable technical potential for the development of wind resources. The achievable potential is much less — sites are eliminated as various factors are considered, including environmental constraints, visual issues, ownership patterns, access to transmission, and other factors. Improved technology, changes in facility costs, and changes in energy prices also influence the viability and achievable potential of sites.

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[273] Chart does not account for utility sales of RECs associated with particular wind projects.

[274] This includes grid-connected installations only. The DPS does not currently have a means of tracking off-grid small wind turbines.

In 2002-2003, the DPS participated in a U.S. Department of Energy study[275] that estimated Vermont's theoretical wind power potential to be approximately 6,000 MW. The study considered the strength of the wind resource and proximity to the existing electric transmission and distribution (T&D) system, as well as using several criteria to exclude environmentally sensitive and other non-compatible land use areas. A 2010 study by the National Renewable Energy Laboratory (NREL) arrived at similar conclusions when considering plants with a 30% gross capacity factor.[276] In 2006, the Green Mountain National Forest updated its Forest Plan.[277] The plan identified over 160,000 acres on which wind development is allowed and approximately 20,000 acres on which wind development actually may be suitable, including the Deerfield Wind Project location.

Many sites identified in the studies above with high wind potential are owned by the state or federal government. In 2003, following a study of the potential wind resources on state-owned land,[278] the Agency of Natural Resources concluded that large-scale wind project development on state lands is incompatible with its mission of land stewardship. The resulting policy, *Wind Energy and Other Renewable Development on ANR Lands*,[279] encourages the development of small-scale projects that help the Agency or its lessees meet on-site energy needs and provide clear environmental and economic benefits. In 2011, ANR did approve the installation of a 100 kW turbine on state forestland leased to the Burke ski area; that now meets roughly 15% of the ski area's electricity needs.[280]

Completed in 1997, GMP's Searsburg wind farm was the first utility-scale wind power facility in the eastern U.S. The project was selected by the U.S. DOE and the Electric Power Research Institute for participation in the Utility Wind Turbine Verification Program, with a goal in part of verifying the performance of wind turbines in cold climates. Ten-plus years of wind measurements indicate the average wind speeds along the ridge are 15 to 17 mph. Annually, the 11 Searsburg 550 kW turbines together produce about 12,000 MWh; this is enough to power about 1,700 homes.

Since Searsburg's development, wind turbines deployed for utility-scale projects have tended to be taller, with larger rotor diameters — and these two factors have led to higher-rated capacity and greater production per turbine (see Exhibit 12-12). These technological developments have allowed for the

[275] Princeton Energy Resources International, *Wind and Biomass Integration Scenarios in Vermont Summary of the First Phase Research: Wind Energy Resource Analysis* (for U.S. EERE, 2002), www.perihq.com/documents/wind-biomass_integration_scenarios_in_VT.pdf

[276] U.S. EERE, *Vermont Wind Resource Map and Potential Wind Capacity,* www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=vt&print

[277] www.fs.usda.gov/detail/gmfl/landmanagement/planning/?cid=stelprdb5333807

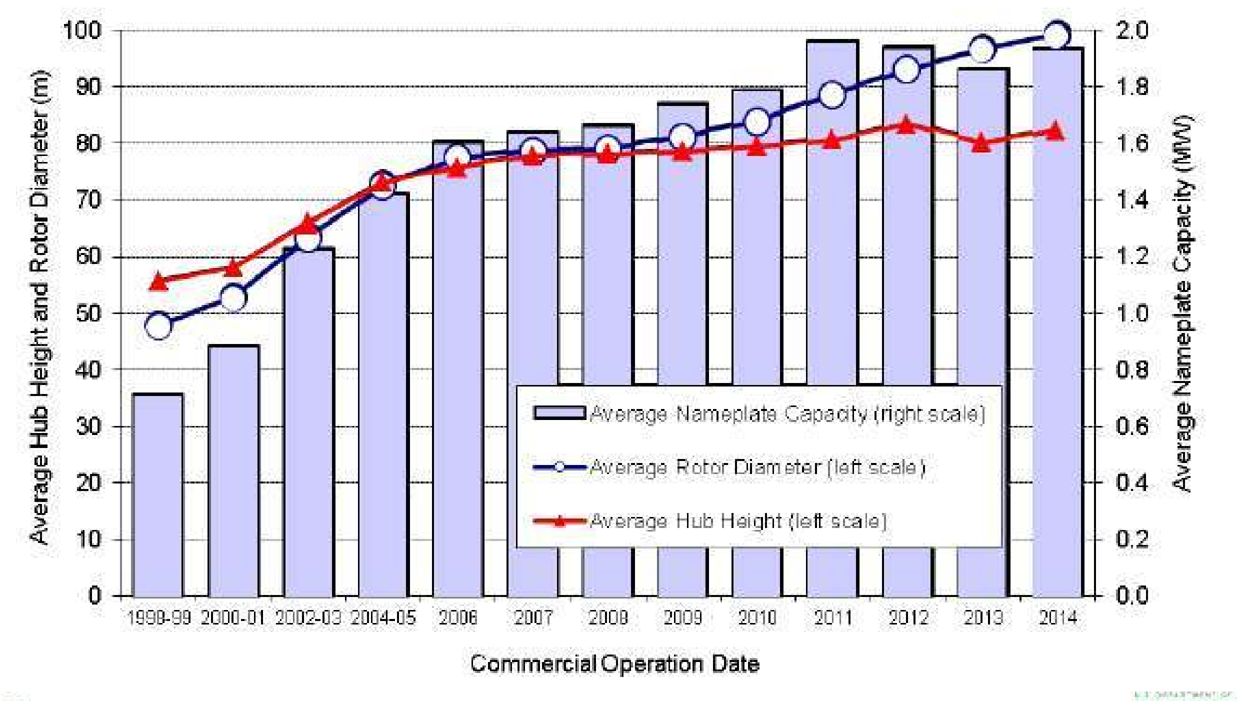
[278] publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Resources/Wind/WindCommissionFinalReport-12-15-04.pdf

[279] Agency of Natural Resources, *Wind Energy and Other Renewable Development on ANR Lands,* fpr.vcms.vt.prod.cdc.nicusa.com/sites/fpr/files/About_the_Department/Rules_and_Regulations/Library/windpower.pdf

[280] National Renewable Energy Laboratory, *Case Study: Burke Mountain Wind Turbine* (2013)

deployment of fewer turbines for a given size of wind farm, and for the siting of turbines in locations that previously were considered to have marginal wind resources.[281] This means that wind farms in Vermont are no longer restricted to ridgelines, though high elevations continue to offer higher-speed and more reliable winds.

Exhibit 12-12. Trends in Turbine Size[282]



Some of these developments are reflected in the wind projects that have been built since Searsburg, as shown in Exhibit 12-12. The First Wind project in Sheffield came online in October 2011, with a rated capacity of 40 MW. Green Mountain Power's 63 MW Kingdom Community Wind in Lowell came online in 2012, as did the 10 MW Georgia Mountain Community Wind on the Georgia-Milton line. These three projects all use turbines between 2.5 and 3 MW in rated capacity, are located at elevations ranging from 1,400' to 2,900', and had capacity factors in 2014 of 27% to 37%. The highest capacity factors (37% and 35%) came from Georgia Mountain and Lowell, at 1,400' and 2,600', respectively — demonstrating that capacity factor in Vermont is not related to elevation alone.

Future wind projects may benefit from modern wind-resource prospecting tools to locate at lower-elevation sites that nevertheless benefit from high wind speeds due to other geographical features. They may capture those winds with modern turbines designed to operate in lower wind-speed environments, to optimize production and minimize the area of disturbance.

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281 U.S. EERE, *2014 Wind Technologies: Market Report*, emp.lbl.gov/sites/all/files/lbnl-188167.pdf

282 Ibid

Sheffield 40 MW wind project as seen from Crystal Lake State Park Credit: DPS Staff

At the other end of the spectrum, small-scale wind facilities — most often using a single turbine, which can range from less than 1 kW to 100 kW for a small commercial turbine — also benefit from careful siting. These turbines, usually located at the site where their energy is used, must be positioned so they extend as high as possible above obstacles; they are less cost-effective than large turbines, thus the economics are very sensitive to production. Technical expertise and warranty protection to maintain the system are also essential to securing years of optimum performance.

Many small- and mid-scale wind turbine manufacturers have gone out of business in the last several decades, leading to industry initiatives such as the Small Wind Certification Council[283], American Wind Energy Association small wind industry standards[284], and Interstate Turbine Advisory Council[285]. Vermont does have a domestic wind turbine manufacturer, Northern Power Systems, whose 100 kW turbines are deployed across the state — including at Burke and Bolton Valley ski areas, the Rock of Ages quarry in Graniteville, Dynapower headquarters in South Burlington, Northland Job Corps in Vergennes, Blue Spruce Farm in Bridport, Nea-Tocht Farm in Ferrisburgh, and Heritage Aviation at Burlington International Airport. Exhibit 12-13 is a map of all the wind projects in Vermont larger than 100 kW.

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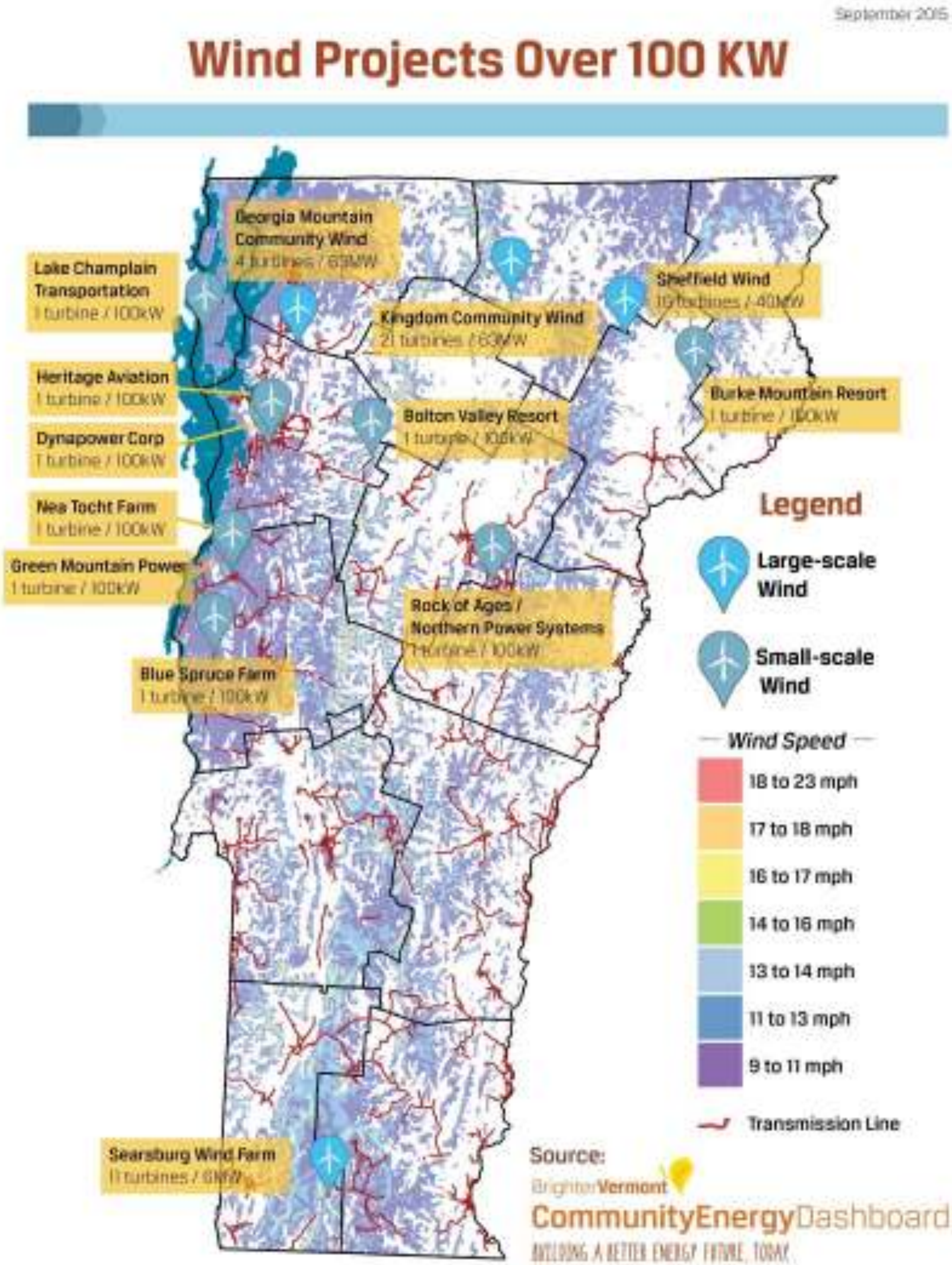
283 Ibid

284 American Wind Energy Assoc., *Small Wind Industry Standards*, www.awea.org/Issues/Content.aspx?ItemNumber=4651

285 Clean Energy States Alliance, *A National List of Eligible Wind Turbines*, www.cesa.org/projects/ITAC/

Northwind 100 at Blue Spruce Farm in Bridport Credit: AAFM Staff

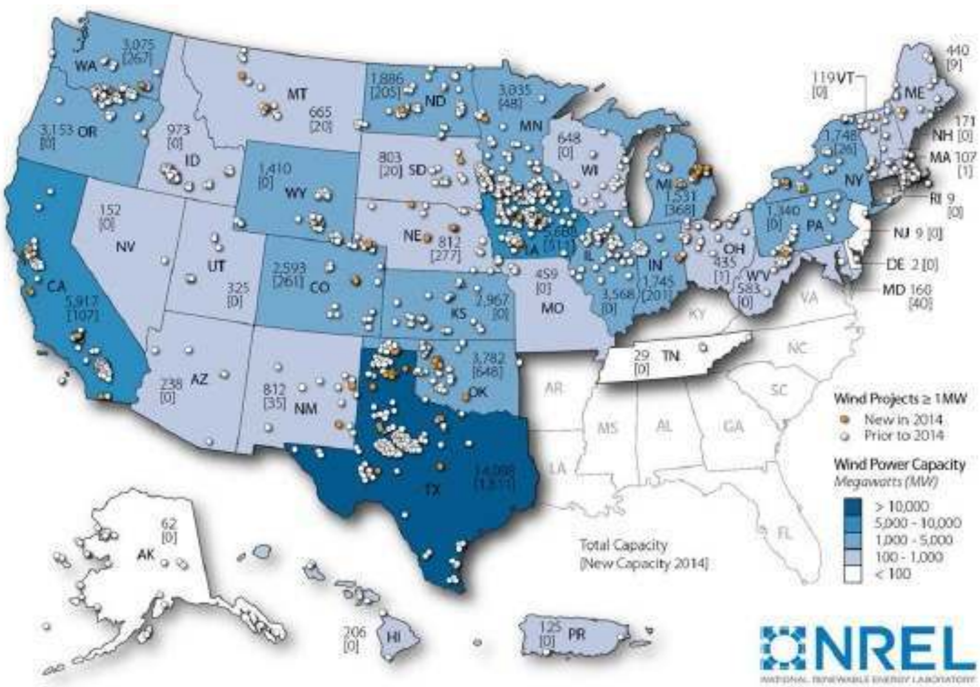
Exhibit 12-13. Wind Installations by Town and Size



12.2.4 Out-of-State Resources

Wind generation projects continue to come online across the Northeast and in bordering Canadian provinces — including the first offshore wind project to "break water" off the coast of New England, Deepwater's Wind's 30 MW Pioneer Wind Farm off the coast of Block Island. Vermont utilities currently purchase some out-of-state wind power and are likely to continue to do so into the future, especially if offshore wind becomes cost-competitive with market power. In November 2010, ISO-NE completed the New England Wind Integration Study[286], acknowledging that development of large-scale wind generation is being driven by public-policy initiatives to increase renewable sources of energy and reduce carbon and other emissions. These initiatives include state renewable portfolio standards, reductions of sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions, and regional efforts to reduce CO_2 emissions, such as the Regional GHG Initiative.

Exhibit 12-14. Installed Wind Capacity by State[287]



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2014

Here is a brief description of wind development goals and some wind projects in progress in our region:

- New Hampshire's 2014 *10-Year State Energy Strategy*[288] identifies 171 MW of operating utility-scale wind capacity, with an additional 2,100 MW of technical potential for land-based wind

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[286] *New England Wind Integration Study* (ISO-NE staff, 2010), www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov162010/newis_iso_summary.pdf

[287] U.S. EERE, *2014 Wind Technologies: Market Report, emp.lbl.gov/sites/all/files/lbnl-188167.pdf*

[288] N.H. Office of Energy & Planning, *New Hampshire Ten-Year State Energy Strategy* (2014) www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

and 3,500 MW of technical potential for offshore wind. In Coos County, NH, the Granite Reliable Wind project has been operating since late 2011. The facility's owner, Nobel Environmental Power, contracted with GMP to purchase 82 MW of the 99 MW project for a period of 20 years that began in April 2012.[289] Two other wind projects are operational in the state: the 24 MW Lempster project and the 48 MW Groton wind project. A number of other facilities have been proposed in recent years by various developers.

- According to Maine's 2015 *Comprehensive Energy Plan Update*,[290] 444 MW of wind have been built in the state, with "significant additional projects proposed" that would produce 3,000 MW of on-shore and offshore wind power by 2020. In addition, the Maine Legislature passed two major initiatives to encourage both on- and offshore wind development: "An Act to Implement Recommendations of the Governor's Task Force on Wind Power Development" (PL 661) and "An Act to Implement the Recommendations of the Governor's Ocean Energy Task Force" (PL 615).

- The *Massachusetts Clean Energy and Climate Plan for 2020*[291] includes a goal of 2,000 MW installed in-state wind power by 2020, much of which is to be supplied from offshore facilities. As of October 2014, wind energy capacity totaled over 100 MW, with over half the installed capacity in community wind projects.[292]

- As of spring 2014, 20 wind energy projects were operating in New York with a rated capacity of a little more than 1,812 MW, enough to power more than 500,000 homes.[293] The *2015 State Energy Plan* anticipates that the state's Renewable Portfolio Standard will lead to the promotion of additional wind onshore wind development, but it places greater emphasis on the potential for offshore wind development as a means of meeting domestic energy needs.[294]

- Hydro-Quebec's on-line wind generation capacity is currently 2,669 MW, with 523 MW under construction and 542 MW planned to be installed by the end of 2017.[295]

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[289] Green Mtn. Power, "The Supply of Electricity" (*Integrated Resource Plan*, Ch. 3) , www.greenmountainpower.com/upload/photos/4773._2014_GMP_IRP_The_Supply_of_Electricity_Chapter_112514_Clean_and_Final.pdf

[290] *Maine Comprehensive Energy Plan Update* (2015), *www.maine.gov/energy/pdf/2015%20Energy%20Plan%20Update%20Final.pdf*

[291] *Massachusetts Clean Energy and Climate Plan for 2020* (2010), www.mass.gov/eea/docs/eea/energy/2020-clean-energy-plan.pdf

[292] U.S. EERE, *Wind Energy Projects*, www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/wind/wind-energy-projects.html

[293] NY Dept. of Environmental Conservation, *Wind Power,* www.dec.ny.gov/energy/40966.html

[294] *2015 New York State Energy Plan,* energyplan.ny.gov/Plans/2015

[295] Hydro-Quebec, *Wind Farms and Generating Stations Covered by Supply Contracts*, http://www.hydroquebec.com/distribution/en/marchequebecois/parc_eoliens.html

It is clear that, regardless of Vermont's own utility-scale wind production, utility-scale wind — especially from offshore projects — will be a growing resource in the regional market. (See Exhibit 13-14 for a map of installed capacity by state.)

12.2.5 Siting and Permitting

In Vermont, the primary permit for all electric generation projects is a Certificate of Public Good (CPG), issued by the Vermont PSB (PSB) under 30 V.S.A.§ 248 (Section 248) of Vermont's statutes. After considering statutory criteria and weighing the overall costs and benefits of the proposed project, the PSB must find that the project promotes the general good of the state.[296]

Among the criteria, the PSB considers orderly development of the region, demand for service, system stability and reliability, economic benefit to the state and residents, and whether there is an undue adverse effect on aesthetics, historic sites, air and water purity, the natural environment, and public health and safety. The orderly development criterion requires that the PSB find a project will not unduly interfere with the region's orderly development by giving due consideration to the recommendations of the municipal and regional planning commissions, the recommendations of the municipal legislative body, and the land conservation measures contained in the town plan.

Statutory parties to the Section 248 process include the DPS, which represents the public interest before the PSB, and the Agency of Natural Resources (ANR), which manages the state's natural resources and oversees the state's environmental regulations. The Vermont Division for Historic Preservation, which reviews many projects for conformance with state and federal historic preservation laws, has developed a protocol for evaluating impacts of wind, transmission, and cell-tower installations on historic resources, to foster predictability in project permitting.[297] To resolve issues and concerns, these agencies, as well as the Agency of Agriculture, Food & Markets, encourage project developers to reach out to them and to landowners and host communities before filing for a Section 248 permit. Some agencies, such as ANR, also issue ancillary permits that projects may be required to obtain in addition to the Section 248 CPG.

The permitting process includes approval of binding plans for transportation, blasting, post-construction monitoring of sound and wildlife impacts, and decommissioning. The PSB considers on-site mitigation; purchase and development of alternative sites; and impact fees for recreational, scenic, natural, and cultural resources deemed unduly affected. Mitigation, alternative sites, and fees need be in place only until the facility is fully decommissioned and the environment repaired, unless there are clearly specified permanent disturbances.

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[296] psb.vermont.gov/sites/psb/files/publications/Citizens%27%20Guide%20to%20248%20February%2014%202012.pdf

[297] Vt ACCD, *Telecom Criteria*, accd.vermont.gov/strong_communities/preservation/review_compliance/telecom_criteria

Many interveners in wind project matters have voiced concern that the PSB process is too complex and expensive for effective participation. Others have faulted a lack of process for resolution of objections apart from full-scale litigation. Meanwhile, project developers ask for relief from higher costs, requirements, and permitting times in Vermont, which often exceed those of neighboring states. Balancing the need for transparency and inclusiveness with the rigor of technical project review and fact-finding in order to build an evidentiary record upon which to base a determination of public good is a challenge the PSB and its stakeholders are constantly working to fine-tune.

In 2004, the Vermont Commission on Wind Energy Regulatory Policy provided recommendations[298] on whether 30 V.S.A. § 248 provided appropriate review of "commercial"[299] wind generation projects. The Commission identified Section 248 as "the appropriate vehicle for siting commercial wind generation projects." It made recommendations that included increasing public involvement and encouraging developers to collaborate early with stakeholders. Many of these recommendations have been subsequently implemented by the PSB, including adoption of a requirement for wind projects to provide notice to municipal legislative bodies and municipal and regional planning commissions within 10 miles of each turbine.

In 2013, the Governor's Energy Generation Siting Policy Commission produced a report[300] containing a comprehensive package of reforms to address concerns with siting and permitting of larger-scale (greater than 500 kW) energy generation projects. Like the 2004 Wind Commission, the Siting Commission's recommendations included a focus on increasing opportunities for public participation; the implementation of procedural changes in the siting process, including greater pre-filing consultation with communities; increased planning; adoption of a simplified, tiered approach to siting; and provision of siting and technology guidance and guidelines. Many of these recommendations required statutory change; but some that did not, such as efforts to enhance regional energy planning, are now underway (see Chapter 11 for details).

12.2.6 Benefits

Like other large electric-generation technologies, wind generation has impacts and tradeoffs that require careful evaluation and decision making. This section discusses these in detail.

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298 http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Resources/Wind/WindCommissionFinalReport-12-15-04.pdf

299 *Commercial* was defined as "larger than net metered projects, which are generally 150 kW or less."

300 Energy Siting Policy Commission, *Siting Electric Generation in Vermont* (2013), sitingcommission.vermont.gov/sites/cep/files/Siting_Commission/Publications/FinalReport/Final%20Report%20-%20Energy%20Generation%20Siting%20Policy%20Commission%2004-30-13.pdf

Relative Cost and Price Stability

Among all forms of new renewable energy electric generation, wind generation is the least expensive to build in Vermont today. A 2013 study in the *Journal of Environmental Studies and Sciences* found that when climate change and health impacts are factored in, electricity generated from wind (and solar) is less expensive than from coal[301] — and a 2015 analysis by the U.S. DOE concluded that wind power will be cheaper than power produced from natural gas within the decade, even without subsidies.[302] Even so, high permitting and construction costs can have a major impact on the total electricity costs of wind power in Vermont.

Once a system is installed, however, operating costs are relatively low, since the wind resource is free. This leads to stable pricing over the projected 20-year life of a typical installation. Given the recent advances in turbine technology that increase operational efficiencies, prices of long-term contracts for wind have reached an all-time low, even in more challenging places to build such as Vermont, at 5-6 cents/kWh. This is on par with average wholesale power prices, and competitive with the expected future cost of burning fuel in natural gas plants.[303]

Reduced Emissions

The generation of wind power itself produces no emissions; and wind generation in New England power markets is "must run," directly displacing generation at facilities with higher operating costs that are dispatchable (coal, oil, and natural gas). The emissions of these facilities, estimated to be displaced by wind, is 914 lb of CO_2 per MWh generated.[304] This means that all the wind projects now installed in Vermont reduce approximately 275 million pounds of CO_2 emissions from the New England grid each year.

Nationally in 2014, the 181.8 million MWh generated by wind energy avoided an estimated 125 million metric tons of carbon dioxide — the equivalent of reducing power-sector CO_2 emissions by 5.7%, or 26.4 million cars' worth of carbon emissions. Moreover, in 2014, wind energy generation reduced water consumption at existing power plants by approximately 68 billion gallons— the equivalent of roughly 215 gallons per person in the U.S., or of conserving the equivalent of 517 billion bottles of water.[305]

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301 Springer Science+Business Media, *Clean Energy Least Costly to Power America's Electricity Needs* (2013), www.springer.com/about+springer/media/springer+select?SGWID=0-11001-6-1436444-0

302 U.S. EERE, *Wind Vision: A New Era for Wind Power in the United States* (2013), www.energy.gov/eere/wind/maps/wind-vision

303 U.S. EERE, *2014 Wind Technologies Market Report*, emp.lbl.gov/sites/all/files/lbnl-188167.pdf

304 *2013 ISO New England Electric Generator Air Emissions Report*, www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf

305 AWEA, *U.S. Wind Industry Annual Market Report Year Ending 2014*, www.awea.org/AMR2014

Economic Impact

As of the end of 2014, the U.S. wind energy industry supported 73,000 full-time equivalent (FTE) jobs directly associated with project planning, siting, development, construction, manufacturing and supply chain, and operations. Vermont firms currently employ 304 workers in the wind energy field.[306] Vermont's wind projects also pay municipal property taxes, in addition to contributing to the state education fund, and may negotiate additional payments to host and neighboring towns. Annual payments to towns have prompted residents of Lowell to vote to eliminate municipal taxes, and residents of Sheffield to vote to cut their tax rate in half.[307]

12.2.7 Challenges

Aesthetics

For project neighbors and for host towns and those within the "viewshed," the aesthetic impacts of wind projects are often a primary consideration. In its review of a project under Section 248, the PSB assesses whether a project will have an undue adverse effect on aesthetics, using the so-called Quechee analysis adopted from Act 250.[308] The DPS usually engages aesthetic experts for the permitting process, to provide testimony to the PSB on the aesthetic impact of proposed wind power projects. The PSB's review of aesthetic impacts is also significantly informed by the overall societal benefits of the project.

As long as wind turbines are visible, and it is necessary to site them at higher elevations, aesthetics will continue to play a major role in the public discourse about wind energy. On its wind resources webpage[309], the DPS has compiled reports, recommendations, and other resources related to aesthetic review of wind projects — such as those produced by the 2004 Vermont Commission on Wind Energy Regulatory Policy and the 2002 Wind Siting Consensus Building Project.

Aesthetic impressions also contribute to concern over the impacts of wind on property values, which are not explicitly considered in the Section 248 process. In 2013, a researcher at the Lawrence Berkeley National Laboratory (LBNL) analyzed sales of 51,000 homes near wind turbines in 27 counties in nine states, and found no statistical evidence that home prices near wind turbines were affected.[310] A follow-on

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[306] BW Research Partnership, *Vermont Clean Energy 2015 Industry Report* (for Vt. DPS, 2015), publicservice.vermont.gov/sites/DPS/files/Announcements/Vermont%20Clean%20Energy%20Industry%20Report%20FINAL.pdf

[307] caledonianrecord.com/main.asp?SectionID=180&SubSectionID=778&ArticleID=91442, caledonianrecord.com/main.asp?SectionID=180&SubSectionID=778&ArticleID=108107, www.miltonindependent.com/georgia-wind-towns-sign-tax-agreement/

[308] psb.vermont.gov/sites/psb/files/248_Guide_March_29.doc

[309] Vt. DPS, *Resources,* publicservice.vermont.gov/topics/renewable_energy/resources#wind

[310] Electric Markets and Policy Group, *A Spatial Hedonic Analysis of the Effects of Wind Energy Facilities on Surrounding Property Values in the United States* (2013), emp.lbl.gov/publications/spatial-hedonic-analysis-effects-wind-energy-facilities-surrounding-property-values-uni

study conducted by LBNL and the University of Connecticut looked specifically at property values for homes near wind turbines in Massachusetts, and again found no measurable impact on property values.[311] Nevertheless, towns in several Vermont communities have lowered home assessments in response to wind projects. It is worth analyzing home sales data in these communities before and after wind project construction, to better understand the actual impact of wind projects on property values.

Environment

Like any other source of energy production, wind power is not free of environmental impacts, and these impacts are reviewed by the PSB in a Section 248 proceeding. Utility-scale projects in the U.S. use available land on the order of 30-141 acres per MW, but with less than one acre per MW of permanent disturbance.[312] The construction of roads for construction and ongoing maintenance can fragment large blocks of habitat; without proper design and construction, those roads have the potential to degrade headwater streams. High elevations provide essential habitat to species such as the Bicknell's thrush, which is also threatened by the effects of climate change.[313] The turbines themselves can be hazardous to flying animals such as birds and bats, through direct physical impacts or internal damage caused by changes in air pressure from spinning blades.

Advances in turbine technology, lessons from operational projects, and research efforts have led to best practices that are essential to avoiding or mitigating impacts to the environment from wind projects. These practices include careful siting to avoid or minimize disrupting or degrading habitat; operational and technological solutions such as halting turbines during times of high bat activity; and methodical pre- and post-construction monitoring of indicators such as stream health, to detect and address issues that may arise. Certificates of Public Good issued by the PSB include conditions requiring multi-year monitoring of a wide range of environmental criteria and periodic (usually annual) reporting to the PSB and relevant state agency (typically the Vermont Agency of Natural Resources). The reports offer valuable insight into the real operational impacts of wind projects in Vermont, and a wealth of data that — especially if comprehensively analyzed — can help inform the design of future projects.

Organizations such as the U.S. Fish and Wildlife Service and the National Wind Coordinating Collaborative are actively engaged in better understanding impacts from wind facilities and offering siting, design, operational, and management recommendations to the wind industry and other stakeholders.[314] The Vermont Agency of Natural Resources also actively engages with developers early in

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311 *EMPG, Relationship between Wind Turbines and Residential Property Values in Massachusetts* (2014),

emp.lbl.gov/publications/relationship-between-wind-turbines-and-residential-property-values-massachusetts

312 Paul Denholm, et al, *Land Use Requirements of Modern Wind Power Plants in the United States* (National Renewable Energy Laboratory, 2009), www.nrel.gov/docs/fy09osti/45834.pdf

313 Vermont Center for Ecostudies, *Breeding Bird Studies in the Mountains*, vtecostudies.org/projects/mountains/mountain-songbird-research/breeding-bird-studies/

314 Wind Turbine Guidelines Advisory Committee, *Recommendations* (memo to acting director, U.S. Fish & Wildlife Service, 2010),

the design stages of projects, to work proactively with them on avoiding and mitigating environmental impacts, and it has developed web-based map tools to help identify important natural resource areas.[315]

Health

Potential impacts to human health from wind turbines can also be of concern to communities and project neighbors. In 2012, the Government of Canada launched the most comprehensive study to date on the effects of wind turbines on public health, releasing findings in late 2014.[316] The only self-reported effect that the study found to be statistically associated with increasing levels of wind turbine noise was annoyance toward wind turbine features such as noise, shadow flicker, blinking lights, vibrations, and visual impacts. Objectively measured results were consistent with the self-reporting findings. Wind turbine noise was not found to be related to measures of sleep quality or physiological indicators of stress, such as hair cortisol concentrations, blood pressure, or resting heart rate. These results are considered preliminary, since Health Canada has not yet published its findings in peer-reviewed scientific journals. However, the findings appear to be consistent with the results of earlier studies described in literature reviews.[317]

There is a larger body of literature available on the public health implications of annoyance from other sources of community noise, including roads, airports, and industry. The World Health Organization developed guidelines to address community noise,[318] and these form the basis of Vermont's current sound limits for wind facilities.[319] In 2014, the PSB opened a docket on the potential of establishing sound standards for generation facilities, including wind.[320] They held three workshops, in addition to soliciting written comments on best practices, but no further orders have yet been issued.

In 2010, the Vermont Department of Health issued a report titled *Potential Impact on the Public's Health from Sound Associated with Wind Turbine Facilities*.[321] It concluded that while there is no direct health effect

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www.fws.gov/habitatconservation/windpower/Wind_Turbine_Guidelines_Advisory_Committee_Recommendations_Secretary.pdf

315 Vt. ANR, *Web Maps,* anr.vermont.gov/maps/web-maps

316 Health Canada, *Wind Turbine Noise and Health Study: Summary of Results,* www.hc-sc.gc.ca/ewh-semt/noise-bruit/turbine-eoliennes/summary-resume-eng.php

317 Jesper Hvass Schmidt and Mads Klokker, *Health Effects Related to Wind Turbine Noise Exposure: A Systematic Review* (U.S. National Library of Medicine, 2014), www.ncbi.nlm.nih.gov/pmc/articles/PMC4256253/, www.ncbi.nlm.nih.gov/pubmed/21914211

318 *Guidelines for Community Noise* (World Health Organization, 1999), www.who.int/docstore/peh/noise/guidelines2.html

319 Vt. PSB, *Sound Monitoring and Noise Complaint Procedures for Wind Generation Facilities,* psb.vermont.gov/forconsumersandthepublic

320 psb.vermont.gov/docketsandprojects/electric/8167

321 Vt. Dept. of Health, *Potential Impacts on the Public's Health from Sounds Associated with Wind Turbine Facilities* (2010), healthvermont.gov/pubs/healthassessments/documents/wind_turbine_sound_10152010.pdf

from wind turbine sound, there is sufficient evidence of a secondary health effect from sleep disturbance due to excessive sound at night. It therefore recommended that nighttime sound levels from wind turbines be limited to 40 decibels or less, measured at the exterior façade of a dwelling and averaged over 12 months.

In addition to complying with sound limits, developers can take many actions to avoid or mitigate annoyance from a wind facility. These include reaching out early to engage project neighbors and communities in a facility's planning stages, incorporating the resulting suggestions into the design and siting of the facility, and offering opportunities to directly share in the ownership, control, or benefits of the project. Developers should also establish a Good Neighbor Policy, have a plan in place to address noise complaints, consider entering into noise easements with abutters, and possibly plan for the purchase of nearby properties whose owners are especially sensitive to the visual or acoustic properties of wind facilities.

Measured Production Capacity

The electric output of a wind turbine is based on its technical capacity and the wind resource at the installed site — the average wind speed. Each project presents an estimated production capacity during the permitting process. Actual production is monitored continually once a project is operational, and it takes a number of years to collect accurate output data. Exhibit 12-15 provides insight into the capacity factors achieved by the large-scale Vermont-based wind projects.

Exhibit 12-15. Vermont Wind Project Capacity Factors[322]

Project	Estimated Annual CF (%)	Actual 2014 CF (%)	Average Annual CF (%)	Maximum CF (%)
Searsburg	27	27	24	31
Sheffield	32	25	24	25
Georgia/Milton	28-34	37	34	38 (2015 YTD)
Lowell	36	35	N/A	39 (2015 YTD)

There is often concern and confusion regarding wind power's *capacity factor*, which is a measurement of the projected or actual energy production versus the maximum output of a facility if it ran at its full rated capacity 100% of the time. Utility-scale wind projects in the Northeast in 2014 generally saw capacity factors ranging from 25% to 40%, with averages in the mid-30s, due to factors including wind resource, turbine technology, and transmission curtailment (see Exhibit 12-16).[323]

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322 Compiled from production data reported to the DPS, Certificate of Public Good filings, compliance filings, and communication with project operators. Figures are rounded to the nearest whole number.

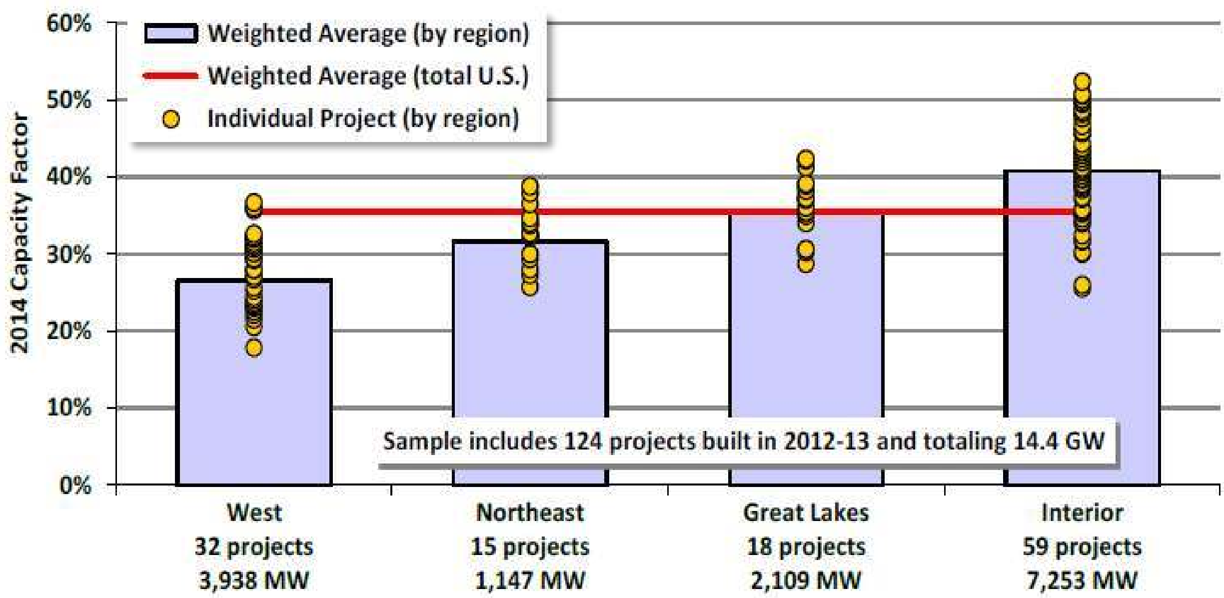
323 U.S. EERE, *2014 Wind Technologies Market Report*, emp.lbl.gov/sites/all/files/lbnl-188167.pdf

Curtailment — or reduction in output ordered by the regional transmission operator — was estimated to be 3.3% in New England in 2014, and is likely to become an increasingly important factor in the feasibility of building new wind projects, especially in transmission-constrained areas of the state and region (see Exhibit 12-17).[54,324] In its 2015 Regional System Plan, ISO-NE discusses specific constraints with respect to wind in Vermont. While central and southern Vermont showed low or minor constraints in their studies, they concluded that northern Vermont is constrained, even with the incorporation of significant grid upgrades.[325]

324 publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/Legislative_Reports/Recommendations%20Related%20to%20Curtailment%20of%20In-State%20Electric%20Generation%20Plants.pdf

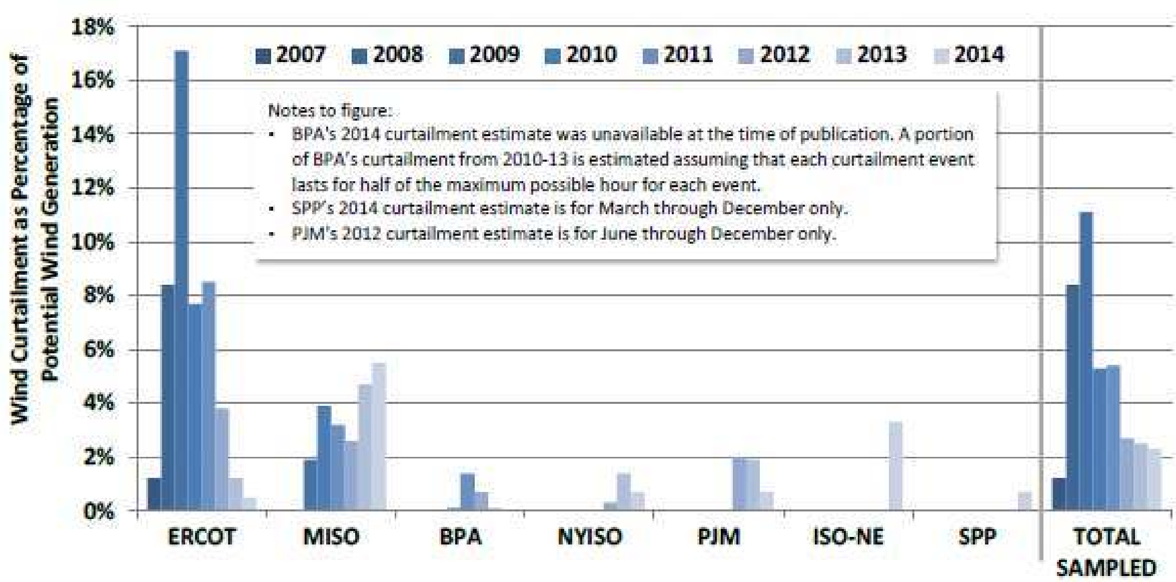
325 http://www.iso-ne.com/system-planning/system-plans-studies/rsp

Exhibit 12-16. Regional Wind Capacity Factors[326]



If the production capacity of a project is found to be below the estimated projected capacity presented during the permit process, its anticipated societal benefits may not be realized. This issue is addressed during the CPG permitting process. The PSB has required reporting of power produced, and has set minimum production requirements for a project that if not met would trigger PSB review of a project's

Exhibit 12-17. Region-Specific Wind Curtailments[326]



[326] *2014 Wind Technologies Market Report,* emp.lbl.gov/publications/2014-wind-technologies-ma

CPG. Cumulative data on the actual power production of wind turbines in Vermont can be used to evaluate the estimated production presented by any new proposed projects.

Wind Variability

The variability of wind generation, coupled with the complexities of accurate forecasting, presents challenges to the reliable operation and planning of the regional power system. In 2010, ISO New England commissioned a study that found wind could meet up to 24% of the region's electricity needs in 2020, and that current generation resources are adequate to compensate for wind variability even at 20% penetration (see Exhibit 12-18 for a comparison of wind penetration in states). However, the study emphasized — and ISO continues to emphasize — the need for flexible resources to compensate for times when the wind doesn't blow, especially within the course of a day.

Exhibit 12-18. Installed Capacity By State and as a Percentage of In-State Generation[327]

Installed Capacity (MW)				Percentage of In-State Generation	
Annual (2014)		Cumulative (end of 2014)		Actual (2014)*	
Texas	1,811	Texas	14,098	Iowa	28.5%
Oklahoma	648	California	5,917	South Dakota	25.3%
Iowa	511	Iowa	5,688	Kansas	21.7%
Michigan	368	Oklahoma	3,782	Idaho	18.3%
Nebraska	277	Illinois	3,568	North Dakota	17.6%
Washington	267	Oregon	3,153	Oklahoma	16.9%
Colorado	261	Washington	3,075	Minnesota	15.9%
North Dakota	205	Minnesota	3,035	Colorado	13.6%
Indiana	201	Kansas	2,967	Oregon	12.7%
California	107	Colorado	2,593	Texas	9.0%
Minnesota	48	North Dakota	1,886	Wyoming	8.9%
Maryland	40	New York	1,748	Maine	8.3%
New Mexico	35	Indiana	1,745	New Mexico	7.0%
New York	26	Michigan	1,531	California	7.0%
Montana	20	Wyoming	1,410	Nebraska	6.9%
South Dakota	20	Pennsylvania	1,340	Montana	6.5%
Maine	9	Idaho	973	Washington	6.3%
Ohio	0.9	New Mexico	812	Hawaii	5.9%
Massachusetts	0.6	Nebraska	812	Illinois	5.0%
		South Dakota	803	Vermont	4.4%
Rest of U.S.	0	*Rest of U.S.*	4,941	*Rest of U.S.*	0.9%
TOTAL	**4,854**	**TOTAL**	**65,877**	**TOTAL**	**4.4%**

* Based on 2014 wind and total generation by state from EIA's *Electric Power Monthly*.

[327] Ibid

Currently wind power is less than 2% of the ISO-NE grid,[328] but there is a focus among system planners on optimizing resources in light of growing energy production from intermittent renewables. At present, 42% of the proposed projects in the ISO's Generator Interconnection Queue are wind-powered.[329]

The issues of optimization need to be considered in the context of the entire ISO-NE power pool, the renewable energy policies of member states, and the increasing penetration of distributed renewable energy other than wind. ISO anticipates needing to adopt more sophisticated forecasting tools, to attract and retain more fast-responding capacity in reserve, and to make regional investments in transmission resources that can connect remotely located wind projects to demand centers.[330]

Strategies and Recommendations

As we weigh the benefits and drawbacks of wind generation, we conclude that wind power should continue to be an important renewable resource for Vermont's diverse electricity portfolio going forward. To improve wind project permitting and siting, and to address some of the concerns that have been raised regarding these projects, we recommend the following:

Strategy 1: Continue to facilitate development of in-state wind projects in order to achieve the state's renewable energy goals, with a particular focus on small- and medium-scale and community-directed projects and projects that offer a significant benefit for ratepayers.

Recommendations

(1) Facilitate the development of projects that are community-led or that have engaged communities in the planning, design, and benefits of the proposed project.

(2) For large-scale projects, development should be permitted if there are environmental, economic, and societal benefits to Vermonters, and all other Section 248 criteria are fulfilled.

Strategy 2: Learn from existing wind in-state wind projects to improve the siting and review requirements and processes for future wind development.

(1) The DPS, ANR, and Department of Health should continue to learn from the operation of existing wind projects to inform any future recommendations for sound, aesthetic, health, environmental, and public engagement guidelines or standards;

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[328] ISO New England, *Resource Mix,* www.iso-ne.com/about/what-we-do/key-stats/resource-mix

[329] ISO New England, New England *Power Grid* www.iso-ne.com/static-assets/documents/2015/02/2015-powergridprofile-final.pdf

[330] ISO New England, *2014 Regional Electricity Outlook,* www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf

(2) *The state should consider formulating requirements for health impact assessments and pre-development public engagement and mediation processes for projects that fail to meet recommended guidelines or standards.*

(3) *In Public Service Board proceedings related to the siting of proposed wind generation projects, the Department should advocate for adoption of sound standards that are clear, readily enforceable, and protective of public health. These standards should be based on solid science, good public policy, and best practices, and would benefit from clear companion guidance regarding monitoring and compliance protocols.*

12.3 Solid Biomass

12.3.1 Overview

Bioenergy is a broad category that includes different types and sources of fuel, with a variety of technologies in use and in development. As described in this report, bioenergy consists of woody and non-woody solid biomass, liquid biofuels, and methane biogas. This section focuses mainly on the use of solid biomass, primarily wood, to provide electric and thermal energy. Agricultural biomass (e.g., straw pellets) and short-rotation woody biomass (e.g., willow plantations) are also included in this section, but are currently a minor source of feedstock for energy. Liquid biofuels and methane biogas are also discussed, later in this chapter.

All forms of bioenergy, like other forms of energy production, have benefits and drawbacks that must be weighed carefully. This CEP discusses some of the ways that Vermont is expanding the use of bioenergy resources while making decisions that are economically, environmentally, and socially responsible. This section concludes with strategies and recommendations for appropriately and sustainably expanding wood supply and demand, primarily for clean, efficient, advanced wood heat.

Wood plays a major role in Vermont's energy mix. An estimated 37% of Vermont households heat at least in part with firewood or wood pellets. More than 100 larger use wood chips or pellets for heating, and this number is rapidly growing. Vermont is a leader in heating schools and institutional facilities with wood chips; more than one-third of all Vermont children attend a school heated by wood. Wood chips also fuel two large wood-fired electric power plants, and a number of smaller commercial and public facilities use wood to create heat and/or electricity.

Other forms of solid biomass are in various stages of research and development, commercialization, and market readiness in the state. As was the case in 2011, there is potential for the use of alternative biomass material other than forested wood for energy production. For example, grass crops such as corn and fast-growing trees such as willows are being investigated for feasibility as part of Vermont energy mix.

Vermont's forest economy is an integral part of a regional and international market, in which product prices fluctuate with supply and demand beyond our borders. Eighty-nine percent of the sawlog volume harvested annually in Vermont is processed within the state, and this value-added local rural economy is essential for many communities and landowners. But wood moves freely through our larger, regional economy, and northern hardwoods — maple, beech, yellow birch, and more — are prized and sought-after throughout the world. Exports of sawlogs from Vermont exceed imports, but only slightly, by a 1.3 to 1 ratio.

The forest products industry in Vermont employs an estimated 10,555 people, and generates $1.4 billion in economic output annually. Vermont's gross state product for all forest-product manufacturing is $266 million, and represents 8% of the state's manufacturing value.

Primary products include solid wood products from sawmills and veneer mills. These primary manufacturers employ 2,327 workers. Payroll in the wood products sector is about $67 million annually. Current annual economic output, in terms of annual sales or value of shipments, stands at $239 million.

Secondary manufacturers transform lumber and other primary solid products into finished consumer products or components for finished products. The making of furniture, moldings, turnings, and similar products employs nearly 1,600 Vermont workers. The annual payroll in this sector is about $49 million. Annual economic output, in the form of sales or value of shipments for the secondary wood products sector, is about $143 million in Vermont.[331]

12.3.2 Principles

Recognizing and strengthening Vermont's current forest-based businesses will have many co-benefits. A strong forest economy encourages landowners to maintain intact forests, it supports forest operations that improve wood quality, and it improves opportunities for good land stewardship. As this CEP evaluates recommendations for expanding wood energy, the interconnection between the forest economy, social benefits, public health, and a healthy forest ecosystem will be a foremost consideration.

The following principles should be considered when developing solid biomass energy policies:

(1) Maintain forest health as a prerequisite to a sustainable wood energy fuel supply, while ensuring continuation of other forest-derived products, values, and benefits.
(2) Improve the economic stability of forestland by expanding opportunities to market low-grade wood as an energy fuel source, while supporting existing forest products and expanding opportunities for secondary forest product development.
(3) Increase the use of modern, advanced clean wood energy technology, especially in areas of at-risk populations.
(4) Maintain in-forest carbon storage and uptake, and support efficient advanced wood energy technology to improve energy use per carbon emitted.
(5) Expand energy production from this renewable — but finite — source by using the most efficient wood energy technology available. Currently, thermal energy and thermal-led CHP applications are favored, due to their conversion efficiency, over wood-to-electric applications.
(6) Use newer, cleaner-burning wood heating systems, to reduce the overall emissions of particulate matter and other air pollutants that may directly affect public health, so that expanding usage of wood energy does not adversely affect air quality.
(7) Improve local infrastructure and technology, to support the expansion of clean and efficient advanced wood energy in Vermont.
(8) Capture the unique and diverse ecosystem services that grass and willow offer.

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[331] Northeast State Foresters Association, *The Economic Importance of Vermont's Forest-Based Economy 2013,* www.nefainfo.org/uploads/2/7/4/5/27453461/nefa13_econ_importance_vt_final_web_jan29.pdf

12.3.3 Policy and Regulatory Framework

Total Energy Study (TES) — The DPS completed a Total Energy Study in December 2014, fulfilling requirements in Act 170 of 2013 and Act 89 of 2013. The approach addressed both the targeted goals set for GHG reductions and an increased use of renewable energy. An additional goal was to increase the use of locally derived fuels in energy production. Wood energy was identified as playing a significant role in achieving these goals. Four scenarios were tested: business as usual, a carbon tax, total renewable energy and efficiency standard (TREES), and total renewable energy and efficiency standard with a local energy requirement (TREES local).

The report emphasized that an increase in wood energy needs to be compatible with goals for air quality, forest health, and efficient use of renewable resources. This could be accomplished using advanced wood-heating systems that are installed in weatherized buildings, so that more buildings could be heated more efficiently, while air quality is improved through the use of improved combustion technology.

This modeling study showed significant increases in jobs and sales in the forestry sector, possibly doubling baseline sales and employment, or at least increasing by 40% to 60% above baseline values.

Federal Tax Incentives — The Federal government in December 2015 extended tax benefits for renewable energy technologies through the production tax credit (PTC) and investment tax credit (ITC). The PTC received a one-year extension followed by incremental reductions before expiring in 2020. The PTC can be claimed at 2.3 cents per kilowatt hour — or an alternative 30% investment tax credit — for new projects that generate renewable electricity from sources including biomass energy projects.

PSB CPG/Section 248 — Under Title 30 V.S.A. §248, the PSB is tasked, before granting a Certificate of Public Good that approves a new project, with ensuring that any new infrastructure for electric energy generation and transmission meets the 10 statutory criteria in the best interest of the public.

Air Emissions — In 2009, Vermont took measures to reduce the substantial pollution from outdoor wood boilers via the Outdoor Wood-Fired Boiler Change-Out program (10 V.S.A. §584). Older boilers sold in Vermont before March 31, 2008 created significant amounts of smoke, whereas modern models emitted 70% to 90% less pollution. By January 2013, several older units were retired and replaced with newer, more efficient boilers that comply with air quality standards.[332]

The EPA has recently released an updated New Source Performance Standard (NSPS) for residential wood heaters, with new emissions standards for modern wood heat being implemented in 2015 and 2020. The revised standards apply only to new units and reflect the improved capabilities of the new units but do not necessarily accurately represent in-use emissions, which are highly dependent on actual operational practices.

[332] Vt. ANR, *Vermont Outdoor Wood Boiler Change-Out Program*, www.anr.state.vt.us/air/htm/OWBChangeOutProgram.htm

Forest Regulations and Best Management Practices

- **Forest Action Plan** — The U.S. Food, Conservation and Energy Act of 2008, commonly referred to as the Farm Bill, included a provision requiring states to complete a statewide forest resource assessment. The Vermont 2010 *Forest Resources Plan and State Assessment and Resource Strategies* set this direction through 2015, at which time a new forest action plan will be adopted. The 2015 action plan includes this vision: "The forests of Vermont will consist of healthy and sustainable ecosystems valued for their significant environmental, societal, and economic benefits. Citizens, landowners, businesses, and government understand their civic responsibility for and participate in the stewardship of trees and forests for this and future generations." Strategies for accomplishing this vision cover topics of biological diversity, forest health and the productive capacity of forest ecosystems, forest products, conservation of soil and water resources, and maintenance of forest contribution to global climate cycles (carbon sequestration).

- **Acceptable Management Practices** — The Acceptable Management Practices (AMPs) for Maintaining Water Quality on Logging Jobs in Vermont are preventative measures that help control soil erosion and protect water quality. They are designed to minimize the effects of logging on natural hydrologic functions of forests. In 1986, the Legislature passed amendments to Vermont's water quality statutes under Title 10 V.S.A. Chapter 47: Water Pollution Control. To further protect water quality, the AMPs were developed and adopted as rules for Vermont's water quality statutes and became effective in 1987. Vermont AMPs are currently being revised to clarify requirements, improve educational components, and strengthen implementation.

- **Heavy Cut Law** — Title 10 V.S.A. Chapter 83: Regulation of heavy cutting was established in 1997 (amended in 2003 and 2005) to prevent large areas of clear cutting without a forest management plan that identifies this as a viable regeneration strategy. Foresters planning to conduct a heavy cut (reducing trees/acre below a silvicultural standard C-line), must notify the state and submit a forest management plan in advance of the harvest for state approval.

- **Wetland Rules —** Title 10 V.S.A. §6025(d)(5) Vermont Wetland Rules were adopted in 2010 to protect significant wetlands of the state. Silvicultural activities are allowed with some restrictions as outlined in 6.01-6.05.

- **Threatened and Endangered Species —** Under Title 10 V.S.A. Chapter 123, activities that could affect a state-threatened or -endangered animal or plant species require a permit from the Department of Fish and Wildlife.

- **Shoreland Protection Act —** In 2015 a new law was enacted that limits activities near ponds and lakes. Harvesting exemptions require an approved plan prior to harvest activities.

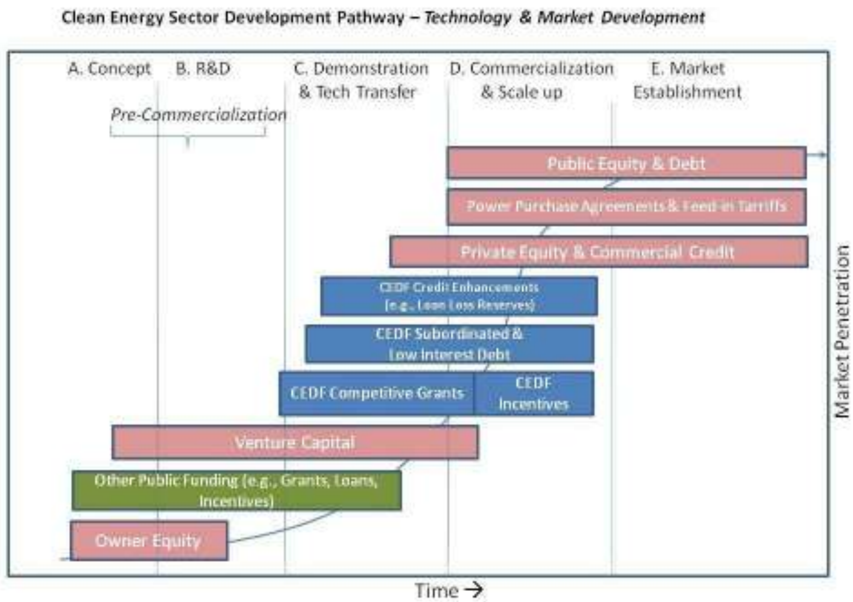
- **Biomass Energy Development Working Group —** The "BioE" group submitted its final report on January 17, 2012[333].

Status of Recommendations to Enhance and Further Develop Wood for Energy

- To maximize the benefits while minimizing negative impacts of the wood energy economy, Vermont Forests, Parks and Recreation has developed voluntary harvesting guidelines that will improve resource sustainability.
- ANR offered a wood stove change-out program for outdoor furnaces, to improve air quality and efficiency.
- ANR, together with the Clean Energy Development Fund, is developing a woodstove change-out program directed at replacing aging, inefficient wood stoves with clean, efficient models — supporting emission (including GHG) reduction and human health by using less wood per unit of thermal energy.
- FPR produced a report on forest fragmentation for the Legislature, with recommendations to strengthen working forestlands, including the need for modifications of Act 250 under criterion 8, and the need for flexibility in establishing thermal energy facilities in growth centers.
- The Working Lands Initiative, created in 2012 to support working forests and farms, offers grants through the Working Lands Enterprise Fund (WLEF). Economic development of forest businesses has been supportive of secondary wood products and markets.
- A company was contracted to analyze Vermont wood markets, the supply chain, and other characteristics of the forest economy, to support marketing efforts and policy development.
- ANR, in collaboration with a number of public and private partners, formed the Vermont State Wood Energy Team. The team provides outreach and technical support services to public schools and affordable housing providers considering the installation modern wood heating systems.
- The Vermont Clean Energy Development Fund (CEDF) has supported wood energy projects.
- The current strategic plan for the CEDF is focused on clean, efficient, and cost-effective energy projects that are beyond pre-commercial stages of development (Exhibit 13-19). The plan's goal for combined heat and power projects is at least 65% efficiency.

333 www.leg.state.vt.us/REPORTS/2012LegislativeReports/272678.pdf

Exhibit 12-19. Clean Energy Development Fund (Blue) Niche, Showing the Select Tools to Help Foster Greater Investment in Clean Energy Projects



- The Agency of Commerce & Community Development has a staff member who facilitates natural-resource commerce projects.
- State aid for construction of wood energy systems in schools is available for emergency situations and school consolidation projects.

<u>Status of Recommendations to Protect Forest Health</u>

- The voluntary harvesting guidelines recommended in the BioE report were used to inform the new FPR Voluntary Harvesting Guidelines.
- The FPR prepared an *Assessment of Timber Harvesting and Forest Resource Management in Vermont: 2012* as a re-assessment of a 1990 study, *The Impact Assessment of Timber Harvesting Activity in Vermont*. This assessment involved the post-harvest evaluation of 81 timber harvesting operations for compliance with the acceptable management practices for maintaining water quality on logging jobs in Vermont, and for potential impacts on a number of other forest attributes that contribute to forest health.
- ANR has developed the Vermont Natural Resources Atlas, with online spatial data layers, in support of natural resource planning to help foresters, landowners, and loggers locate and protect species and natural communities at risk.
- Educational training for loggers is offered annually through the Logger Education to Advance Professionalism Program (LEAP).

- FPR continues to monitor rates of forestland gain or loss, harvest, and growth of timber, in collaboration with the USDA Forest Service.
- The Department of Fish & Wildlife published a *Wildlife Habitat Landowners Guide,* including methods for monitoring residual wood biomass and wildlife tree retention that can be used for post-harvest monitoring as part of the Use Value Appraisal program.
- The state has posted online public information on home use of firewood, including improved efficiency and air quality gained from using dry wood.

Voluntary Harvest Guidelines —Title 10 V.S.A. §2750, Act 24 requires the FPR commissioner to develop voluntary harvesting guidelines by January 2015, for use by private landowners to help ensure long-term forest health and sustainability. Harvests conducted on state lands and wood purchased by the state are to be consistent with these guidelines, with the objective of achieving long-term forest health and sustainability along with other management objectives.

Act 56 (H. 40) Biomass and Renewable Energy Credits — On June 11, 2015, Governor Shumlin signed into law H. 40, An Act Relating to Establishing a Renewable Energy Standard (RES). This law establishes a mandatory renewable energy standard for Vermont utilities. H. 40 repeals Vermont's Sustainably Priced Energy Development (SPEED) Program, except for the Standard Offer program. The RES requires that retail electricity providers have a minimum amount of renewable electricity in their supply portfolios (Tier 1); support relatively small (less than 5 MW) renewable energy projects connected to the Vermont grid, known as distributed generation projects (Tier 2); and invest in energy transformation projects that reduce fossil fuel use for heating and transportation (Tier 3).

To qualify for Tier 2, a biomass plant must generate both electricity and thermal energy from same fuel, with the majority of the energy recovered being thermal. Biomass energy production for Tier 2 or 3 must comply with renewability standards to be adopted by the FPR commissioner. Biomass projects that do not qualify as distributed renewable generation or energy transformation can still qualify under the total renewable energy tier.

This act took effect on July 1, 2015. ANR is directed to report on the environmental and land use impacts of renewable electric generation, methods for mitigating impacts, and recommendations for appropriate siting and design.

12.3.4 Environmental Considerations

Environmental Protection Agency Carbon Policy

The carbon emission impacts of switching from fossil fuels to wood fuel are very complicated, due in part to the complexity and variability of forests, and are intertwined with the natural carbon cycles of forests.

Forests pull carbon from the atmosphere and store vast quantities in soil, trees, and other vegetation. This process of carbon uptake reduces atmospheric carbon, moderating the rate of climate change and its associated impacts. The cumulative effect of many trees removing and storing carbon from the atmosphere across large areas is significant. Aspects of this include the amount of stored carbon and the process of uptake by forests as they change; as they are exposed to various stress factors; and as they are harvested and processed into durable wood products, used for other products, or burned for heat and power. In large part because of this complexity, the results are often unreliable when we develop general policies to employ when assessing positive or negative GHG benefits in the abstract.

Burning wood can emit a higher gross amount of carbon dioxide per unit of energy than burning oil. However, burning wood emits *biogenic* carbon, which has been constantly cycled between forests and the atmosphere over time as part of the natural carbon cycle. In contrast, burning oil emits *geologic* sources of carbon, taking this fossil carbon that was stored beneath the surface of the earth for millions of years and sending it on a one-way path into the atmosphere. Burning wood emits carbon that was previously in the atmosphere 20-100 years ago, while burning oil emits carbon that was in the atmosphere 20-100 *million* years ago.

For use in evaluating bioenergy emissions, the U.S. EPA has been working for many years to develop an accurate, scientifically worthy, economically feasible biogenic accounting method of quantifying forest carbon changes. The current draft version relies on two factors that are important to this CEP: whether the wood used as fuel in biomass systems is “waste” wood, resulting from harvesting sawlogs, or if it is harvested solely for energy; and whether harvesting is conducting in a manner that maintains forest health and its capacity for ongoing removal and storage of atmospheric carbon dioxide.

Forest Sustainability Standards

Private forest landowners have flexibility in forest management objectives and methods. There are many voluntary guidelines for managing forests sustainably, and a few organizations have established specific standards to be followed to garner a sustainability certificate.

The American Tree Farm System (ATFS) has a forest-sustainability measurement system whose use is required of participants. There are 493 tree farms in the Vermont ATFS program, for a total of 172,209 acres.

The Forest Stewardship Council (FSC) has a set of standards used to evaluate responsible forest management. While FSC is a voluntary program, it uses the power of the marketplace to protect forests for future generations. By 2013 in Vermont, 74,175 acres of forestland had been FSC-certified.

The Sustainable Forestry Initiative (SFI) is a certification system that requires independent, third-party audits performed by internationally accredited bodies. These standards cover key values such as protection of biodiversity, species at risk and wildlife habitat, sustainable harvest levels, protection of water quality, and prompt regeneration. The SFI updated its standards in 2015.

12.3.5 Health Considerations

Heating with biomass rather than fossil fuels may be beneficial for reducing long-term net greenhouse gas emissions, in turn reducing climate change and associated health impacts. At the same time, expanding wood energy usage in Vermont raises some air quality concerns, with potentially negative implications for public health.

The primary pollutant of concern from biomass combustion is fine particulate matter ($PM_{2.5}$)[334], but combustion of wood and other biological materials emits additional pollutants — including nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), and potential carcinogens including benzene and polycyclic aromatic hydrocarbons (PAH) — in amounts similar to other solid fuels. Biomass combustion tends to result in lower sulfur dioxide (SO_2) emissions than does fuel oil combustion, but it emits substantially more of certain other pollutants including $PM_{2.5}$, CO, and PAHs compared to the combustion of oil and gas. While recent state and federal regulations impose stricter limits on particulate matter emissions from wood boilers, it is important to consider the health effects of $PM_{2.5}$ and other pollutants so that proper steps can be taken in promoting best practices to reduce pollution emissions and minimize adverse health effects.

Health effects related to $PM_{2.5}$ include heart and lung impacts, and exacerbation of asthma and other respiratory conditions.[335] According to a recent World Health Organization report, residential heating by wood in North America was responsible for 8.3% of the total $PM_{2.5}$ and was associated with 9,200 premature deaths per year.[336] Scientific evidence suggests that any increase in $PM_{2.5}$ emissions, regardless of how high or low background $PM_{2.5}$ levels currently are, will have a negative health impact.[337] Early trials indicate that emissions from agricultural biomass combustion are generally worse than emissions from woody biomass combustion.[338]

Carbon monoxide (CO) is a product of incomplete combustion, and is typically emitted by all combusting fuel sources, albeit in different concentrations. CO can accumulate in poorly ventilated spaces, and can pose a significant acute and chronic health hazard. Typically, CO emissions from wood burning increases with fuel moisture. Good combustor design, use of dried/seasoned fuel, and proper operation of the wood-burning device help minimize CO and other emissions.

The number of wood stoves currently in use may be dominated by older models that lack efficient and clean combustion technology. Studies of uncontrolled exposure to wood smoke from undeveloped countries illustrate health impacts of $PM_{2.5}$ that should be avoided. Understanding the dramatic air quality improvements achieved with new vs. older-model wood stoves should make a compelling argument for wide-scale implementation of newer models across the state.

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334 World Health Organization, *Health Effects of Black Carbon*, *http://www.euro.who.int/__data/assets/pdf_file/0004/162535/e96541.pdf*, (2012)

335 Anderson, JO et. al. *Clearing the Air: A Review of the Effects of Particulate Matter Air Pollution on Human Health.* Journal of Medical Toxicology. Volume 8, Issue 2 (June 2012) pp 166-175.

336 World Health Organization. *Residential heating with wood and coal: health impacts and policy options in Europe and North America (2015)* *www.euro.who.int/__data/assets/pdf_file/0009/271836/ResidentialHeatingWoodCoalHealthImpacts.pdf*

337 Sigsgaard T et. al. *Health impacts of anthropogenic biomass burning in the developed world.* European Respiratory Journal. (Sept 24, 2015) Epub ahead of print

338 Brassard P, et.al. *Comparison of the gaseous and particulate matter emissions from the combustion of agricultural and forest biomasses.* Bioresour Technol. (March 2014) pp. 155-300-6

Topography, meteorological conditions, and building design can create highly variable emissions from wood heat. Fine PM concentrations are known to vary widely across the landscape, with mountain valleys often experiencing much higher levels than detected by fixed monitoring stations.[339] Wood smoke can account for more than half of the fine particle concentrations in Vermont mountain valleys on calm, cold winter mornings. Certain valley locations such as Rutland are more susceptible to wood smoke impacts. A 2004 analysis in Rutland indicated that wood smoke contributed one-fifth to one-third (depending on temperature) of $PM_{2.5}$ during the heating season.[340] Rutland monitoring data indicated that winter $PM_{2.5}$ emissions were higher in 2014 and 2015 than the prior 10-year average.[341] Meanwhile, recent data show that residential wood combustion increased between 2008 and 2015.[342]

It is also possible that expanded wood burning that does not include advanced emission controls may be inappropriate in certain locations — such as concentrated residential areas, in mountain valleys prone to temperature inversions, or in areas where sensitive populations such as children or older adults could suffer adverse impacts.

While pellet stoves generally have lower emissions than cordwood stoves, wood pellets present several additional health concerns, and are the reason Vermont is requesting that standards be developed for pellets. A recent analysis of the elemental composition of wood chips and pellets indicated that toxic elements, including arsenic, copper, and chromium, were found in some samples at levels exceeding European standards, presumably from the inclusion of preservative-treated or painted waste wood.[343] There are currently no state or federal standards in the U.S. that regulate wood chip and pellet production. Additional health concerns are tied to wood pellets where stored in large quantities in basements or other enclosed spaces. Several deaths have been reported related to carbon monoxide poisoning, and concerns exist regarding off-gassing of other potentially toxic chemicals.[344] Proper storage and ventilation can help alleviate these concerns.

All heating fuels have some negative impacts. Making comparisons across fuel types and considering all possible implications and trade-offs, including health, environmental, and economic concerns, is a

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339 New York State Energy Research and Development Authority. *Spatial Modeling and Monitoring of Residential Woodsmoke Across a Non-Urban Upstate New York Region.* (February 2010) Final Report 10-02

340 Allen, G, et.al. *Evaluation of a New Approach for Real Time Assessment of Wood Smoke PM,* Paper # 16, A&WMA International Spec. Conf. on: Regional and Global Perspectives on Haze: Causes, Consequences and Controversies, Asheville, NC (2014)

341 Poirot, R, *Air Quality and Climate Extremes.* Presented at: Responding to Vermont Climate Adaptation Needs: A Roundtable Showcasing Available Climate Data and Tools (2015)

342 Paul Frederick, *Vermont Residential Fuel Assessment Survey [VRFA Survey] for the 2014-15 Heating Season,* VT Dept. of Forests, Parks, and Recreation (2015)

343 New York State Energy Research and Development Authority, *Elemental Analysis of Wood Fuels.* (June 2013) Final Report 13-13

344 Gauthier S, et.al. *Lethal Carbon Monoxide Poisoning in Wood Pellet Storerooms—Two Cases and a Review of the Literature.* Annals of Occupational Hygiene (2012), Vol 56, #7, pp.755-763

challenging exercise due to the numerous complexities and uncertainties. For those already using wood for residential heating, strategies that can be used to improve air quality and reduce greenhouse gas emissions include:

- Replacing older, uncertified wood stove/boiler technology with modern wood heating devices;
- Using properly aged and stored wood;
- Improving the operation and maintenance of stoves/boilers; and
- Improving energy efficiency of buildings.

Additionally, air purifiers with HEPA filters have been demonstrated to improve indoor air quality, and can be especially valuable for those with wood-burning devices that may have higher indoor PM levels due to wood smoke leakage and recirculation of exhaust, and for those with pre-existing respiratory conditions or other conditions that increase vulnerability to PM.[345]

12.3.6 Resources

In-State Wood Energy Production

Space heating represents one-third of Vermont's total energy demand — and 80% of that is met by fossil fuels (one-half being oil). Despite our state's long and continuing tradition of heating with wood, only 15% of Vermont's heating demand is currently met that way. This presents an enormous opportunity for expanding the use of efficient, clean-burning wood technologies, while at the same time creating markets for low-quality wood. That creates an economic incentive for improving timber quality, boosts value-added prospects for durable wood products, and supports forest landowners in keeping forestland intact.

Current Solid Biomass Use for Thermal Energy

Wood is a relatively low-cost, local source of thermal energy. Wood boilers are used in nearly 300 systems throughout the state (Exhibit 13-20). Although the price per unit is increasing at about the rate of inflation, the cost of wood is projected to remain significantly less expensive than other heating fuels into the future, and its pricing has been relatively stable through times of fossil fuel volatility. The prices of wood chips used by schools and institutions have been even more stable, increasing less than the rate of inflation. As efficiencies for wood-fired furnaces, boilers, and stoves increase, annual fuel costs for the user are expected to decrease.

[345] Noonan CW, et. al. *Indoor Air Quality Improvement Following Interventions in Wood Stove Homes.* Abstracts: ISEE 22nd Annual Conference, Seoul, Korea, 28 August-1 September 2010: Indoor and Built Environment. Epidemiology, (January 2011) Volume 22, Issue 1, p. S42

Exhibit 12-20. Current Vermont Wood Boiler Use

Building Type	Number of Installations
Businesses	19
College campuses and complexes	5
Low-income multi-family complexes	24
State buildings and district heating systems	13
Schools	60
Bulk pellet residential boilers	200 +/-
Total	**299 +/-**

Exhibit 12-21. Wood Boiler Technologies and Fuels

Technology	Cordwood boilers	Pellet boilers	Single facility wood chip heating	District heating with wood chip boilers	Industrial combined heat and power
Typical heat output capacity	20kW-100kW	20kW-1MW	500kW-9MW	1.5MW-15MW	8MW-150MW
Application	Home heating and farm buildings	Home heating and small commercial buildings	Schools, hospitals, office buildings, etc.	College campuses and downtown communities	Merchant power plants
Fuel type	Cordwood	Pellets	Wood chips	Wood chips	Wood chips
Annual fuel use	2-15 cords	2-20 tons	100-10,000 tons	500-50,000 tons	1,000-500,000 tons
Fuel sourcing	Locally harvested firewood	Premium pellets	Paper grade and screened bole chips	Bole chips and whole-tree chips	Whole-tree chips and hog fuel

Given the largely unregulated market, it can be expected that in general, wood prices will play a dominant role in determining how much wood goes to the different energy uses. However, certain incentives at the federal level affect decisions about where to send processed biomass. Energy markets are influenced by federal incentives, such as the 30% energy investment tax credit or production tax credits, and by renewable-portfolio-standard incentives in other states that are available to Vermont electric generators. Such incentives do not exist for commercial thermal users, who make decisions about fuels based on market prices and other factors such as convenience. Any projected or desired uses of biomass for thermal energy must account for these factors, which may impede progress.

The CEP encourages increased thermal use of cordwood, wood chips, and densified fuels (e.g., wood or agricultural crop pellets), and it supports school, district, or community biomass energy systems along with the combined heat and power systems discussed in the next section. We recognize the higher efficiency of using natural resources in space-heating technologies, the higher value of displacing imported oil and propane, the need to adequately manage the air quality effects of combustion, and the economic benefits for rural areas associated with wood harvesting and fuel production.

Act 47 of 2011 (30 V.S.A. § 209(d)(7) and (8)) mandated that Efficiency Vermont be authorized to offer incentives for installation of woody biomass heating systems in a manner that promotes deployment of such systems. These incentives, together with additional incentives from the Vermont Small Scale Renewable Energy Program for biomass equipment, are helping to drive increased use of biomass in the state.

Coupling residential energy retrofits that create an efficient home envelope with the use of fuel derived from local resources would move Vermont toward optimal energy usage, and would minimize impact on wood biomass supplies.

<u>Residential and Commercial Use</u>

Wood is widely used for residential heating in Vermont: an estimated 37% of Vermont households use it as a primary or secondary heat source.[346] Wood heat has increased in popularity in schools as a replacement for fossil oil fuel, and pellet use has jumped as homeowners and small commercial buildings convert to pellet stoves and boilers. Local wood use for heat keeps $43.6 million circulating in the local economy, replacing heating oil that would have cost $149.1 million[347].

Replacing natural gas systems for home heat with wood systems would improve our renewable energy portfolio, but cost and emissions would not be improved, given current prices and heating equipment efficiency. That said, 51% of Vermont households still heat with oil, burning about 89 million gallons of heating oil each year, or 725 gallons per household. Substituting wood for oil in an advanced wood-heating system would save homeowners money, support local wood markets, reduce fossil fuel use, and improve long-term net GHG emissions.

Vermont households burned an estimated 347,500 cords (around 869,000 tons) of wood in 2014-2015 — an increase of about 33,000 cords over the amount used during the 2007-2008 season. In 2014-2015, about 37% of Vermont households burned wood for at least some space heating, a 4% increase from the 2007-2008 survey. Those using wood for primary heating consumed about 4.8 cords in 2014-2015, while those using wood as a supplementary source used 2.1 cords. In that same heating season, Vermont households burned about 126,000 tons of wood pellets, with primary-heat-source consumers burning 4.4 tons and supplementary-heat-source consumers burning 3.3 tons for the season. Combining cordwood with the 252,000 green tons needed to make pellets for residential heating required about 1,121,000 tons of wood. All in-state uses of wood for fuel in 2013 totaled 2.3 million tons. [348]

There is great potential for the utilization of more wood resources as cleaner, more efficient wood-burning appliances are installed in more homes and businesses, and with the development of district heating in communities. Home heating with firewood is not for everyone, however, as it requires a substantial amount of work. Homeowners must have access to local wood suppliers — or, if they wish to

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[346] *VRFA Survey*

[347] *Vermont Wood Fuel Supply Study,* Biomass Energy Resource Center (2012)

[348] *VFRA Survey*

supply their own firewood, adequate woodland on which to cut it. Storage space is also required. For those with chronic respiratory conditions, wood burning may not be an option.

Instead of firewood, homes can be heated with pellets made from biomass. During the 2014-2015 heating season, 31,000 households (12.1%) burned at least some wood pellets for space heating.[349] Wood pellet stoves are increasingly popular because of their cleaner emissions, higher efficiencies compared to wood stoves, and greater ease of operation — including the advantage of operating on thermostats, much like oil, gas, and propane systems.[350]

Sales of pellet-burning systems nationwide grew from 18,360 in 1999 to 141,208 in 2008. Sales in 2011 stood at 62,451.[351] In Vermont in 2015, an estimated 8,000 households that did not already own a wood or pellet stove either had installed or were planning to install a new one.[352] Advances in fuel delivery capabilities and services that mimic the ease of use of fuel oil and propane increase the prospects for pellet use in the state.

At $294 per ton of wood pellets, the cost to heat with an 80% efficient pellet stove or boiler in November 2015 was $22.41 per delivered MMBtu. Cordwood burned with 60% efficiency cost $17.21 per delivered MMBtu.[353] One ton of pellets provides roughly the energy equivalent of 120 gallons of fuel oil, and one cord of wood yields about the equivalent of 150 gallons.

District Heating

District energy systems, which provide heat from a central source to a number of buildings, can result in significant efficiencies in heating (and cooling). These systems are widely used in Europe. The DPS has been exploring the use of new, highly efficient biomass combustion technologies as a primary energy source for district energy. The state has two large biomass district energy systems already in place, in the Capitol complex in Montpelier and the state office complex in Waterbury. Several college, institutional, and commercial buildings in the state use wood in district systems, connecting multiple buildings to one boiler.

District Heat Montpelier is a joint project of the City of Montpelier and the State of Vermont to provide local renewable energy to downtown Montpelier. Installed as part of the rebuilding of the state's central heating plant in 2013 and 2014, modern wood-fired boilers heat the Capitol Complex and 21 buildings in

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349 *VRFA Survey*

350 While wood pellets are the dominant fuel used for pellet stoves, research and development into densified grass (e.g., grass pellets, briquettes) and other agricultural biomass (e.g., corn) continues in Vermont, and these fuels are beginning to become available.

351 Pellet Fuels Institute, *Hearth Industry Unit Shipments 1998-2011*, www.pelletheat.org/assets/docs/industry-data/2011-us-hearth-shipments.pdf

352 *VRFA Survey*

353 Vt. DPS, *Vermont Fuel Price Report,* publicservice.vermont.gov/publications/fuel_report

downtown Montpelier, including city and school buildings as well as private customers. The ongoing benefits of district heat in Montpelier include:

- Reducing health-threatening air emissions from fuel combustion by as much as 11 tons per year.
- Replacing approximately 300,000 gallons of oil per year, between the state and downtown buildings, with locally or regionally produced wood chips.
- Stabilizing fuel costs for city government and the school department — creating the potential for tax dollars to be directed toward services or infrastructure, rather than to paying rising oil prices.
- Creating an incentive for economic development in downtown Montpelier, by providing private building owners with a cleaner, potentially cheaper source of heat.
- Removing many private oil furnaces and underground fuel oil storage tanks from potential flood areas.

Electricity Generation

Vermont currently hosts two wood-fired biomass electric facilities: Burlington's 50 MW McNeil Generating Station and the Ryegate 20 MW plant. Woody biomass is also used for combined heat and power (CHP) in some businesses, colleges, and other institutions around the state.

Opening in 1984, the McNeil plant was the first in-state wood-fired generator, providing a market for low-grade wood and creating jobs and economic benefits throughout Vermont. Because of a combination of wood-supply and bid-pricing issues, McNeil does not operate as a baseload facility as originally envisioned, but rather functions as an intermediate plant that operated at a 65.6% capacity factor in 2014. Although the plant can use oil or natural gas, it runs primarily on wood chips, using 1.45 tons of wood to produce each MWh.[354] The plant burned just over 440,000 tons of wood fuel in 2014.[355]

McNeil was constructed with the idea that it could provide district heating either to the University of Vermont or to Burlington, making use of the energy otherwise lost. In April 2014, a second feasibility study was completed by Ever-Green Energy of St. Paul, Minn., focused specifically on using the heat by-product from McNeil to meet the thermal energy needs of the collaborators at the Fletcher Allen Hospital (now University of Vermont Medical Center), and buildings on the UVM campus.[356]

Wood used in Vermont's two power plants is sourced from Vermont and from surrounding states and provinces. Since 1984, some wood fuel has also been shipped from Vermont to power plants in New Hampshire, Maine, and New York. In 2011, 193,000 green tons of biomass chips were exported to

[354] Burlington Electric Dept., 2008 Integrated Resource Plan

[355] Vt. Dept. of Environmental Conservation, Air Quality Division

[356] Ever-Green Energy, *Burlington, Vermont*, www.ever-greenenergy.com/projects/burlington-vt/

surrounding states, while 479,000 green tons were reported to have been imported into the state.[357] This illustrates the regional market for wood: as a commodity, it is being bought and sold across borders throughout the region.

Wood fuel has evolved from being essentially a waste product to being a commodity whose price is reflective of its economic value. For most of the period from 1984 to the present, wood-fueled power plants relied on a blend of wood processing residues, wood from forest harvesting, and wood residues from municipal and other sources.

The limited efficiency of wood-fired electric generation plants presents a challenge to the development of more wood-fueled power generation. The upper end of efficiency — typically around 25% for electric-only woody biomass plants — is low compared to other uses. As reflected in the volume of public comments received by the DPS in opposition to electric-only woody biomass power, many people are interested in seeing that forest resources be used as efficiently as possible.

The past five years have been a time of speculation for wood-fueled power generation. Both new utility-scale and smaller-scale developments have been proposed throughout our wood-supply market. Though none have yet been built in Vermont, new facilities such as the 75 MW Burgess Biopower facility in Berlin, NH, are operating in the region — and the practical outcome will be increased regional competition for fuel-grade wood.[358] Exhibit 13-22 shows the wood-fired power plants (blue) and pulp mills (yellow) that are located adjacent or close to Vermont.

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[357] North East State Foresters Assoc., *The Economic Importance of Vermont's Forest Based Economy 2013*, fpr.vermont.gov/sites/fpr/files/Forest_and_Forestry/Vermont_Forests/Library/NEFA13_Econ_Importance_VT_final_web_Jan29.pdf

[358] Lisa Gibson, *Groundbreaking Held for N.H. Biopower Plant,* Biomass Magazine (Oct. 6, 2011), biomassmagazine.com/articles/5846/groundbreaking-held-for-nh-biopower-plant

Exhibit 12-22. Wood Production and Power Facilities in New England

Source: Dept. of Forests Parks and Recreation

Given the inherent limits and increasing demands on forests in the region, the CEP recommends a focus on higher-efficiency uses of woody biomass energy. At the time of the first CEP's release in 2011, two woody-biomass electric-production facilities were proposed in Vermont; each would have yielded approximately 30 MW of electricity, with the potential that a portion of their thermal energy generated could be used for other purposes. Neither the North Springfield nor the Fairhaven project received a Certificate of Public Good permit, although the latter remains on hold and has not been cancelled.

Details of the PSB Order on the North Springfield project illustrate concerns regarding the evaluation of potential impacts on forest health:

> *Absent a harvesting plan that is sufficient to protect long-term forest health and sustainability, the Project would have an undue adverse impact on Vermont's forest resources.*
>
> *Impacted forest components will vary from harvest site to harvest site. Therefore, the best approach for avoiding undue adverse effects from harvesting is to identify critical natural resource concerns and the harvesting standards needed to safeguard them based on the current understanding of forest science.*
>
> *To support this approach, the following forest components should be accounted for in harvesting operations:*
>
> - *Protection of species and areas of special concern, including necessary wildlife habitat, including deer yards, wetlands, vernal pools, bear mast areas, Rare, Threatened and Endangered species ("RTE"), and S1, S2 and S3 natural communities.*
> - *Support for wildlife habitat and biodiversity through retention of snags, and down woody material.*
> - *Renewal of soil health through retention of down woody material and limited soil disturbance.*
> - *Adherence to laws and rules including Acceptable Management Practices and Heavy Cut.*

- *Management for non-native invasive plants to prevent transport and spread.*
- *Adherence to forest insect and disease quarantines and policies.*
- *Promotion of adequate regeneration and healthy residual stands.*
- *Preparation of forests for climate change adaptation (build resilience).*

All harvesting should follow written silvicultural prescriptions based upon accepted silvicultural practices reflecting stand conditions, landowner objectives, and referencing appropriate silvicultural literature and guides."[359]

In rejecting the permit for the North Springfield facility, the PSB stated, "that the Project would not promote the general good of the State of Vermont, with consideration given to the Project's expected annual GHG emissions and the low level of thermal efficiency at which the Project would operate."

Combined Heat and Power (CHP)

Facility siting is one of the challenges facing all biomass power. Siting challenges include the limited number of properties suitable for industrial development, coupled with infrastructure limitations related to transportation, public systems (e.g., water, sewer), and combined heat and power distribution.

Locating a host facility that has the ability to use the magnitude of excess heat produced on a continuous basis is a major challenge. People generally do not want power plant-sized facilities to be located in or near population centers; but this is exactly where such facilities must locate to use the thermal load, unless industrial processes make use of it. Retrofitting the existing electric power plants, McNeil and Ryegate, has additional difficulties. The McNeil plant has the potential to add a heating loop because of its proximity to the University of Vermont campus and Medical Center, and to the city of Burlington. Ryegate has no such potential host within a feasible distance, although it has the capability to heat about 1,300 homes.

Siting is one of the challenges facing all biomass energy facilities. Siting challenges include the limited number of properties suitable for industrial development, coupled with infrastructure limitations related to transportation, public systems (e.g., water, sewer), and combined heat and power distribution. Additionally, to protect public health, advanced technologies to control emissions of particulate matter from biomass combustion may be required.

The Standard Offer Program currently requires biomass plants to meet an efficiency level of 50% to be eligible. With an electric-only plant's efficiency less than 30%, the only way to meet the requirement is with a CHP plant — which was the intent of the eligibility requirement. This requirement should be modified to include a mechanism for incentivizing CHP plants that might initially be less than 50% efficient, but will increase their efficiency over time.

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[359] Public Service Board Order for Docket 7833, entered 2/11/2014, psb.vermont.gov/sites/psb/files/orders/2014/2014-02/7833%20Final%20Order.pdf

In addition to the two large biomass power plants, there are several smaller institutional and commercial CHP wood-fired biomass operations. Collectively, these micro CHP facilities add only a few MW of electric capacity to Vermont, and consume about 44,000 tons of wood per year.[360]

Given Vermont's limited state incentives and financial resources, these should flow first to the most efficient projects that displace the most fossil fuel for the investment: thermal-led energy facilities, including district heating, and CHP projects. It should be noted that financial incentives, such as the production tax credit and RPS incentives in other states, favor electric development. The recommendation to prioritize thermal uses of woody biomass means that Vermont will have to be vigilant in its own policy, so that federal incentives do not function as the main determinant for energy development in the state.

Other Biomass Energy Production

Solid biomass also includes fast-growing plants such as willow and densified grass products, both of which are burned for thermal energy. Middlebury College investigated the use of short-rotation willow plantations as fuel for its wood energy facility. The first harvest was poorly stored and too wet to burn properly, with insufficient volume to obtain correct combustion settings on the boiler. Middlebury has harvested its seven-acre plot a second time, and is using some of the willow as a product (ski gates for the slalom course) and as planting stock for stream-bank restoration.[361] Meach Cove Farm has been burning switchgrass pucks in a boiler designed for high-ash fuels for most of the 2014-2015 heating season; results show normal efficiencies and combustion characteristics.

Market Development Status and Strategies for Grass and Willow Energy

Yields of Grass in Field Trials — As a result of the efforts of the University of Vermont Extension's field trials, in collaboration with Vermont Sustainable Jobs Funds' Bioenergy Initiative, yields of switchgrass (*Panicum virgatum*) and several other grasses are well-established, at between three and five tons per acre. For example, in trials at three sites, using five varieties of switchgrass, yields after three years ranged from 2.5 to 6.5 tons per acre, with an average of 4.4 tons.[362] These yields align with those in places that have similar climate and soil conditions, such as the states of New York and Pennsylvania and the Province of Ontario.

A "polyculture" blend of grasses yielded more than four tons per acre at all sites, and would be resilient in the face of changing rainfall and other weather conditions. Yields of miscanthus (*Miscanthus gigantean*), a non-invasive, infertile clone, can be seven tons per acre, and it seems to do well in some of Vermont's wetter, heavier soils.

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360 Estimate of wood-fuel usage in Vermont in 2013 provided by Vt. Agency of Natural Resources

361 *Middlebury Willow Site Yields More than Research Data*, Middlebury College (April 2014), www.middlebury.edu/sustainability/news-events/news/2014/node/475222

362 Sid Bosworth and Tim Kelly, *Evaluation of Warm Season Grasses for Biomass Potential in Vermont*, (UVM Extension, 2013), pss.uvm.edu/vtcrops/articles/EnergyCrops/Vermont_WSG_Biomass_Report4.2013revised.pdf

Yields of Willow in Field Trials — Trials at Middlebury College over the six years since planting with two harvests have shown a yield of four tons per acre per year.[363] The trial encompasses seven acres.

Utilization of Grass — A new way to handle grass has emerged for its use in boilers from 100,000-500,000 Btu per hour: compress the grass into 2.5-inch diameter rounds. This scale of boiler is now manufactured in the U.S., and using grass as its fuel makes sense because the boiler is large enough to justify incorporating advanced combustion to burn a low-cost, high-ash fuel, and too small to justify the cost of a wood chip system with traveling auger to handle the chips.

Utilization of Willow — Ideally, willow plantations are coppiced every three years, and harvested with equipment similar to forage-harvesting equipment. Work over the last five years at the State University of New York, College of Environmental Science and Forestry, with the farm implement manufacturer Case New Holland, has yielded a viable harvester. It is based on existing technology for an animal-forage harvester, and can harvest approximately 75 tons per hour. Starting with stems as thick as 4.75", it yields chips 0.4" to 1.75" long, harvesting approximately five acres per hour.[364]

The CEP recognizes the potential for the greater use of biomass material other than solid wood. These sources have begun to prove themselves in terms of expected agronomic yields in Vermont conditions, and the pathways to utilization have also become clearer. As a way to diversify fuel supply and stabilize farm income, both grass and willow could contribute to thermal production in Vermont in the next five to seven years. Some technical hurdles remain, and continue to be addressed.

As with wood fuel, utilization rates depend on the strength of the relevant economic sector (agriculture rather than forestry, in this case) and on the price of fossil fuels. Unlike wood fuels, which are already available, switchgrass and willow plantings take three years to mature (although often a harvest in the second year is worthwhile). The state will coordinate its overall strategy to include these sources and associated technologies, and will evaluate their potential for Vermont as they develop.

Forest Resource Characterization

We depend on forests for their material and economic contributions of timber, veneer, pulpwood, firewood, chips and pellets (for both space heating and electric generation), and maple syrup — and on the values and services that forests provide, such as water supply and water quality protection, flood control and protection, wildlife habitat and biodiversity, clean air and carbon sequestration, outdoor recreation, and scenic beauty. It is in this context that we consider expanding forest use as a renewable energy source.

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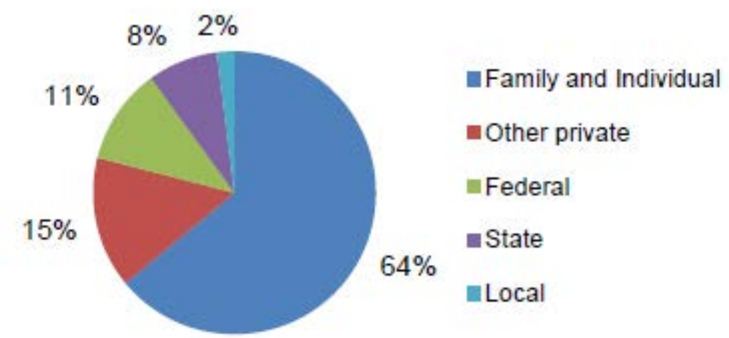
[363] Shun Shi, et. al., *Yield of 30 Shrub Willow Cultivars Over Two Rotations In a Yield Trial At Middlebury Vermont,* (International Poplar Symposium VI, July 20-23, 2014. Poster Presentation)

[364] Eisenbeis, M. et. al. *Evaluation of a Single-Pass, Cut-and-Chip Harvest System on Commercial-Scale Short-Rotation Shrub Willow Plantations*, BioEnergy Research, Vol. 7, Issue 4 (December 2014) pp. 1506-1518

Forests dominate Vermont's landscape. Three quarters of the state is forested by a mix of species, ages, and forest types. The majority of Vermont's forestland is held by private landowners (80%). Approximately 2.9 million acres, 62%, of forestland are owned by families and individuals[365] (Butler et al 2015). Corporate-owned forests encompass 681,000 acres, and other private forests encompass only 133,000 acres. Unlike other northeastern states with large corporate ownerships, a relatively small percentage of Vermont's forest is owned by businesses, including timberland investment management organizations (TIMOs) and real estate investment trusts (REITs). A smaller proportion of Vermont's forest is public land (21%). The federal government holds 491,000 acres (11%) of forestland, most of which is administered by the Green Mountain National Forest (446,400 acres). The state holds 368,000 acres of forestland (8%) in various state agencies, including state parks and forests, and local governments hold another 73,000 acres of forestland (2%) (Exhibit 13-23).

Exhibit 12-23. Ownership of Forests in Vermont



Source: U.S. Forest Service, Forests of Vermont and New Hampshire 2012

Forest health is of utmost importance in any discussion of forest use. Healthy forests are highly resilient and capable of self-renewal. They maintain forest processes and are structurally complex, ecologically productive, and composed of diverse native plants and animals. Although it is unrealistic to revert to pre-settlement forest conditions, striving toward healthy forests can be compared to creating and maintaining the characteristics of relatively undisturbed forests of the region. Healthy forests support and maintain biological communities (species assemblages), support physical elements of the ecosystem (soils, air, water), and support ecological processes (nutrient cycling).

Vermont's forests provide crucial habitat for healthy and sustainable populations of native plants and animals. We have between 24,000 and 43,000 species (of which 653 are rare), and nearly 100 natural community types. Many of these species and communities are associated with forested conditions.

Healthy forests play a vital role in absorbing water and moderating its movement across the landscape. Although forests cannot prevent large floods outright, they do temper their frequency, intensity, and extent, which in turn significantly reduce loss of life and property damage from serious flooding. Forests

[365] Butler et al., 2015

intercept rain, meltwater, and runoff, and they prevent impurities from entering our streams, lakes, and groundwater. Forests have this effect on water in part by slowing it down, spreading it out, and allowing it to sink into the soil. As they slow water down and spread it out, forests limit erosion and the ability of water to transport sediment, nutrients, and pollutants that can cause problems for water treatment plants, recreation, or functional wildlife habitat. Absorbed water permeates soil and is filtered before reaching surface waters. Tree canopies shade streams, maintaining the cool temperatures necessary for many aquatic species and for keeping algae in check.

Tree leaves serve as sponges for many air pollutants, removing them from circulation where they can do harm to humans. Forests provide Vermonters with enormous benefits and a range of critical services. A thriving forest economy, functioning natural systems, and Vermont's quality of life rely on maintaining blocks of contiguous forests across our landscape. There is much at stake in maintaining healthy forests, and careful planning can allow for harvesting that is compatible with forest health goals.

Prices

The harvest and manufacturing of forest products in Vermont contributes $1.4 billion in annual economic output[366]. Pellet fuels and cordwood continue to be a substantial part of this overall output. Over the past decade, markets have experienced significant volatility in fuel prices. Concerns regarding $100 per barrel have faded as oil has traded under $40 recently. Prices for cordwood remain less expensive for consumers when comparing cost per unit energy, but recent decreases in fuel oil have reduced the price advantage for pellets. As of November 2015, cordwood was about half the price per MMBtu of propane, and approximately 16% less than fuel oil. Pellets were about 9% more expensive than fuel oil per MMBtu, but about a third less expensive than propane.[367]

Projections for Wood Supply

Wood availability as a fuel source for thermal and electric energy hinges on continued forest growth, regeneration success as a foundation for future forests, and competitive market prices that can support landowners in maintaining working forestland.

One measure of wood supply is the estimate of forest growth compared with harvest. In an unregulated market, the supply can be variable — but net annual growth currently exceeds harvest on a statewide basis by nearly a 2:1 ratio. Local availability of wood does vary around the state depending on acres of forestland, tree species, forest age and maturity, local wood markets, operability, ownership, and other factors.

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[366] North East State Foresters Assoc., *The Economic Importance of Vermont's Forest Based Economy 2013*, fpr.vermont.gov/sites/fpr/files/Forest_and_Forestry/Vermont_Forests/Library/NEFA13_Econ_Importance_VT_final_web_Jan29.pdf

[367] Vt. Department of Public Service, *Vermont Fuel Price Report* (November 2015)

Current inventories show that Vermont's forests add 166.6 million cubic feet (2.1 million cords) of timber growth per year, while about 70.2 million cubic feet (0.9 million cords) are harvested[368]. For context, Vermont's forest holds 8,593 million cubic feet (107.4 million cords) of standing timber (including trees five inches or greater in diameter). While the supply is substantial, not all this wood is available for use as energy wood.

Landowner Economics

The annual carrying cost of land is a significant factor in whether private forestland can be owned, managed, and maintained in large blocks into the future. Unlike the annual return from an agricultural operation, working forestland is typically managed on longer rotations, whose income-generating harvests are spread out over years and often decades. If economic pressures befall forest landowners, they may have limited options to generate income and may turn to subdividing and parcelizing portions of their land.

The property tax is one key economic variable for landowners. Vermont's Use Value Appraisal (Current Use) program is intended to stabilize property-tax rates, and to assess working lands at their value for either agricultural or forestry use. This program has been instrumental in keeping annual property taxes affordable and allowing forestland owners to hold and steward parcels of 25 acres or larger. Maintaining and strengthening the Current Use program is a key strategy for supporting forest integrity.

Pressures on Wood Supply

Fragmentation — The most recent FIA estimates from 2013 show a continuing, though gradual, loss of forestland that since 2007 has totaled about 75,000 acres. As slow but steady development growth resumes, it is clear from the FIA data that our forestland is no longer expanding, and in the long term is vulnerable to land use conversion and fragmentation.

As forest fragments become ever smaller, practicing forestry in them can become operationally impractical, economically nonviable, and culturally unacceptable. In turn, we lose the corresponding and important contributions that forestry makes to our economy and culture. The result is a rapid acceleration of further fragmentation and then permanent loss.

Forest health, sustainability, management opportunities, and the ability of forestland to provide needed products and ecosystem services and suitable habitat are affected to varying degrees, and in different ways, by changes in the fragmentation of forests and urbanization.

Climate Change — Despite the wealth of this state's forest resources, there are indications of a future that may look quite different from today. Climate change presents a major challenge to forests' ecological and economic viability. Although there is uncertainty about the timing and magnitude of forest impacts, it is

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[368] Morin, R.S. & R. Riemann, *Forests of Vermont*, *2014*. USFS Resource Update 54 (2015)

clear that forest changes have been occurring and will continue. The capacity of Vermont's forest species to adapt to change will depend, in part, on how carefully they are managed and conserved today[369].

Non-Native Forest Pests — As humans have moved plant material from one region to another, non-native forest pests have affected forests. At present there are three known insect pests that could significantly affect Vermont forest health in the near term: the emerald ash borer, the hemlock woolly adelgid, and the Asian long-horned beetle. Wood movement has been largely responsible for pest movement between states, and several quarantines are now in place to slow the spread of these insects. In 2015, the Legislature passed a law to ban untreated firewood movement across Vermont borders. This law will be implemented by July 2016.

Overseas Market Demand — European demand for wood pellets has emerged as a significant factor in Eastern pellet markets. The European Commission's 2009 Renewable Energy Directive mandated that by 2020, the European Union (EU) fulfill at least 20% of its energy needs from renewable sources. In FY2014, the United States exported 3.8 million metric tons of wood pellets, mainly from the Southeast, 97% of which went to the EU. That year, the U.S. claimed a 60% share of the EU wood pellet market, up from 44% in 2013.[370] Much of this demand is coming from electric utilities that are switching from coal to meet their EU targets.

There have been efforts to site a pellet facility near a deepwater port in Maine, for export to the EU, but no facilities are operating at present. However, given the demand from the EU nations to meet their energy targets, the Northeast is likely to see additional efforts to supply wood energy products to Europe in the future, which may in turn impact the price and availability of woody biomass products in Vermont, and the long-term health of the region's forests.

Benefits and Challenges for Increased Use of Woody Biomass

Among the reasons to increase the usage of woody biomass in the state, the following stand out:

- Replacing fossil-fueled heating systems with advanced wood-heating systems will benefit local businesses, the forest product economy, and Vermont forest landowners by keeping funds local rather than supporting overseas economies.
- Increasing the use of advanced wood-heating systems will generate more energy output per wood input, so less wood will be required to support current or future use.
- Replacing older wood-heat technology with advanced systems will improve air quality.

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369 Vt. Dept. of Forests, Parks & Recreation, *Creating and Maintaining Resilient Forests in Vermont: Adapting Forests to Climate Change* (2015), fpr.vermont.gov/sites/fpr/files/Forest_and_Forestry/The_Forest_Ecosystem/Library/Climate%20change%20report_final_v6-18-15a.pdf

370 Foreign Agricultural Service, USDA, *Money Does Grow on Trees as U.S. Forest Product Exports Set Record* (2015), www.fas.usda.gov/data/money-does-grow-trees-us-forest-product-exports-set-record

Including thermal wood energy as part of the total energy mix will help the state meet its goals for increasing local, renewable energy, and reducing the state's GHG emissions.

Expanding the use of woody biomass must overcome a variety of obstacles. Many advances have been made to improve the efficiency and reduce the emissions of residential stoves and furnaces — but even so, many Vermonters continue to use older, inefficient, polluting stoves that have higher life-cycle costs and cause greater environmental harm than EPA-certified models. A 2014-2015 survey found that 30% of Vermont households that heat with wood used pre-1990 wood stoves or fireplaces[371].

Emissions of fine particulates and other air pollutants vary considerably, depending on stove age, type, and operation. Wood smoke affects indoor and outdoor air quality, and is linked with health impacts such as asthma.[372] For example, the relative emissions of fine particles from the uncertified stoves that many people use are 4.6 lb./MMBtu of heat output, whereas from newer EPA-certified stoves, they are 1.4 lb./MMBtu of heat output, and for pellet stoves, they are 0.49 lb./MMBtu of heat output.

Higher-efficiency stoves reduce the wood consumed per stove, decrease emissions by at least 70%, and can displace other fuel sources such as oil, gas, and propane.[373] The health benefits associated with reducing fine-particle emissions, including wood smoke, are significant. If all the old woodstoves in the U.S. were changed out to cleaner-burning hearth appliances, the EPA estimates that at least $35 billion in health benefits per year could be realized.[374]

Given the potential for increased air pollution from certain biomass units, it is important for policymakers to keep local air quality concerns in mind when encouraging the substitution of wood for fuels like oil, propane, and natural gas.

Statewide education activities could significantly increase the energy that Vermonters produce, using the same amount of fuel wood, while helping improve performance of heating systems. Potential education topics include wood stove performance and the quality of the fuel wood used, planning ahead to purchase and properly dry wood, and use of advanced wood heating systems to maximize efficiency of fuel use and reduce emissions.

Optimizing our renewable resources by using them appropriately and efficiently will stretch our money and our resources to reach more of our energy demands without additional fuel wood.

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[371] *2015 Vermont Residential Heating Assessment*

[372] U.S. EPA, *Asthma*, www2.epa.gov/asthma

[373] EPA, *Burn Wise*

[374] U.S. EPA, *Strategies for Reducing Residential Wood Smoke*, www3.epa.gov/ttn/oarpg/t1/memoranda/strategies-doc-8-11-09.pdf

Strategies and Recommendations

<u>*Strategies*</u>

(1) Encourage, promote, and incentivize converting fossil fuel heating systems to clean and advanced wood heating systems by: encouraging local manufacturing of advanced wood heat technology, supporting development of wood delivery infrastructure, supporting development of sustainable forestry and procurement services, expanding processing facilities, encouraging bulk delivery systems, advancing installation technology, and providing training and education on the benefits of heating with efficient, clean wood energy systems.

(2) Support programs that strengthen Vermont forest product economy, keeping forest land economically viable and maintaining working forest land (e.g. UVA).

(3) Support clean air and health of Vermonters through a combination of standards, regulations, incentives, education programs, impact assessments, and mitigation strategies designed to promote efficiency, minimize emissions, and avoid impacts on vulnerable populations or places.

(4) Retain the two Vermont power plants fueled with wood as a valuable part of the forest products economy and our state energy mix, work to use the waste heat, and upgrade efficiency as technology becomes available.

(5) Diversify solid biomass options by continuing to support agriculture-based biomass (e.g., native and perennial grasses and short-rotation willow). Assess potential for grass and willow energy crop cultivation in coordination with regional planning agencies, conservation advocates, and farmers.

<u>*Short-Term Recommendations*</u>

(1) Conduct an intensive, statewide education campaign to provide best practices on cordwood and wood pellet selection, storage, and combustion to promote the most efficient, clean, and cost-effective use of technology while protecting human and environmental health.

(2) Maintain forest health as a prerequisite to a sustainable wood energy fuel supply, while ensuring continuity of other forest-derived products, values, and benefits. Actions include:

- *Update the Vermont wood supply analysis, and support development of a predictive model for forest growth and yield that more accurately assesses future wood supply.*

- *Maintain monitoring efforts by ANR that include trends in forest growth and regeneration, forest harvest levels, tree health (including abiotic and biotic threats to tree health), water quality, forest carbon stocks, wildlife habitat quality, and other ecosystem measures that are essential to understand trends and provide assistance to forest landowners in maintaining forest health and a sustainable wood supply.*

- *Promote the use of the 2015 Voluntary Harvesting Guidelines to inform best management practices.*

- *Implement education programs for natural resource professionals and develop strategies that promote high-quality forestry practices, such as forester licensing, to further protect forest health.*

- *Conduct outreach and education on quarantines and regulations designed to reduce the threat of destructive forest pests that may be moved on/in wood fuel.*

(3) *Promote the expanded use of advanced wood heating, where appropriate, using equipment that has high efficiency and low emissions. This includes supporting wood stove change-out programs, such as the one offered previously by the ANR Air Quality and Climate Division. This also includes supporting change-out programs to substitute fossil-fueled heating equipment with advanced wood heating equipment, where appropriate, to reduce net carbon emissions, promote local wood fuel sources, and expand the use of this renewable resource.*

(4) *ANR, PSD, and Vermont Department of Health work collaboratively to assess the human health impacts associated with different wood energy systems to support residential and commercial heating choices.*

(5) *Provide support to hire a Wood Energy Forester at FPR that would coordinate planning and execution of a wood energy education campaign, a strategic plan to expand the use of modern wood heating technology, and to meet the renewable energy goals for wood energy identified in this plan.*

(6) *New electric generation from wood should include combined heat and power technology to maximize efficiency. A priority should be placed on the expansion of wood in the thermal energy market, where efficiency can be as high as 80-90%.*

(7) *Harvest and continue to gather data on existing field trials of grasses and willow as energy crops. Expand field trials in ways that build on results from Vermont's current field trails, and from best practices in New England, Quebec, New York, and Ontario.*

(8) *Support combustion trials and emissions testing of grasses and other agricultural field residue in boilers in the 100,000-500,000 Btu/hr. range, specifically boilers with advanced combustion and emissions controls. Gather and review relevant studies of best available combustion technology for grasses.*

(9) *Explore development of state, regional, or federal standards for elemental composition of wood pellets to ensure that contaminants and emissions from these fuels are accurately characterized and minimized.*

(10) *Review federal and state air regulations for all biomass combustion devices — including wood stoves, pellet stoves, furnaces, hot water heaters and boilers — and consider revisions to ensure appropriate and effective regulation of all devices. Appropriate and effective regulation may include more stringent minimum emission standards and requirements for all devices, as well as lower permitting thresholds for larger devices where the permit may establish more stringent emission standards, health impact assessments, fuel quality requirements, testing requirements, monitoring requirements, siting requirements, and operation and maintenance requirements as appropriate.*

Long-Term Recommendation

(11) *In order to achieve the state's goal of doubling wood's share of building heating by 2035, improve local infrastructure and technology to support continued expansion of clean and efficient advanced wood energy systems in Vermont:*

Develop a comprehensive action to serve as a roadmap for further expansion of the use of advanced wood heat in Vermont, including strategies to increase the number of buildings heating with wood fuels, promotion of locally sourced wood, expansion of "best in class" advanced wood heating equipment that is clean, efficient, and cost effective, expanding weatherization of buildings to keep heat in, replacement of fossil heating fuels, assessment of health impacts and mitigation options, ensuring continuity of other forest-derived products, and strategies to maintain forest health and forest values and benefits beyond wood use for thermal energy.

12.4 Liquid Biofuels

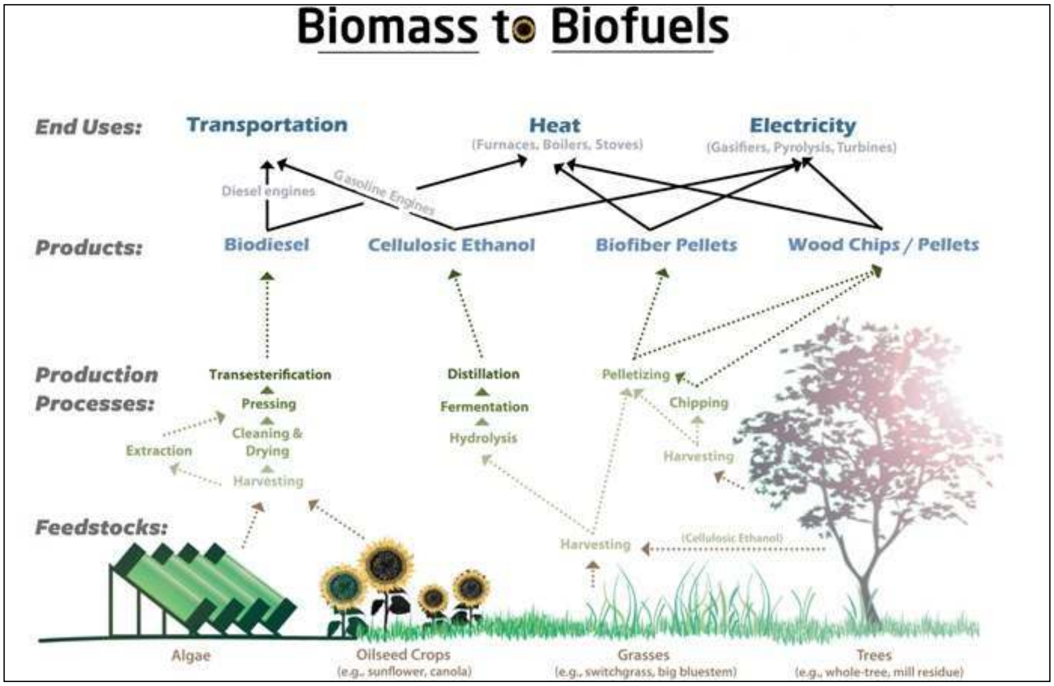
12.4.1 Overview

Biofuel is fuel produced directly or indirectly from organic material. Often referred to as secondary biofuels because they must be processed before use, liquid biofuels include starch and cellulosic ethanol, and biodiesel. Liquid biofuels are particularly useful because, unlike woody biomass, they can be used in transportation applications and in existing heating infrastructure. If sustainably produced, biofuels can displace fossil fuels, support local economies and job growth, and lead to lower GHG emissions and better air quality. Along with reducing our dependence on foreign oil, greater utilization of liquid biofuels can help Vermonters reduce air and groundwater pollution by lowering the amount of petroleum pollution released into the environment. Vermont has potential for producing biofuels, especially biodiesel, that can support the economy and keep energy spending in state.

There are many types of liquid biofuels, created from various feedstocks. The characteristics of these fuels vary greatly — from how sustainable they are, to the commercially available supply, to the price and appropriate applications. Recommendations for each type of liquid biofuel will vary depending on these characteristics. In general, Vermont should strive to convert from fossil fuels to biofuels, while at the same time working to make biofuels more sustainable and affordable. Vermont should also work to stimulate a local, sustainable biofuel production economy.

As currently produced, ethanol is a less attractive option for the state because of environmental concerns, including poor energy return on energy invested and questions about its climate change impact. Biodiesel is more attractive because it performs well on many environmental metrics, including energy return on energy invested, land use, and GHG emissions.

Exhibit 12-24. Biomass and Biofuels Usage



Source: Vermont Sustainable Jobs Fund

Biodiesel is an oil-based diesel substitute derived from oilseed crops, waste oil, or algae. Biodiesel is easy to use, biodegradable, nontoxic, and sulfur-free. It is produced in the U.S. primarily from soybean oil, although corn oil, canola oil, palm oil, and animal fats are also used.

Biodiesel can be blended with diesel up to 5% to form B5, a blend that can be safely used on-road in diesel engines. Diesel is used primarily in heavy-duty and medium-duty vehicles, and in some light-duty vehicles. Blends greater than B5 void some equipment and vehicle warranties. Few renewable fuels exist that are suitable for medium and heavy-duty transportation applications — so the commercial availability of biodiesel blends represents progress in this area. Many Vermonters use pure biodiesel, B100, in off-road applications to power farm equipment or other small diesel engines.

Biodiesel can also be blended with no. 2 home heating oil up to 20% to form B20, and safely burned in existing furnaces and boilers. Blends of biodiesel and home heating oil are sometimes referred to as Bioheat, an industry-trademarked term that usually applies to blends of 2%-5% biodiesel, 98%-95% petroleum-based home heating oil. Higher blends are available, and blends of up to B20 (20% biodiesel, 80% petroleum-based home heating oil) are approved for use in existing equipment.

Ethanol is ethyl alcohol, which can be blended with gasoline and used in internal combustion engines. It is derived from the fermentation of agricultural products — usually corn, sugar, or grains — to form starch or sugar ethanol, or from the processing of agricultural wastes, grasses, or wood to produce cellulosic ethanol. Ethanol can be blended up to 10% with gasoline to form E10 and used in any engine that takes regular gasoline. In blends greater than 10%, specialized adaptations (or flex-fuel vehicles) are necessary because ethanol corrodes rubber fuel system parts. Ethanol is suitable for use in light-duty transportation applications. Ethanol also reduces the ozone-forming emissions of internal combustion engines, so E10 is required in many urban areas that do not meet federal air emission guidelines. Vermont is in compliance with federal law, so oxygenated fuel is not required here, although most gasoline sold in the state is E10.

Both biodiesel and ethanol emit fewer GHGs at the point of combustion than gasoline, fossil diesel, or home heating oil, and have a positive energy return on energy invested, if only by a slim margin. These fuels and their feedstocks perform differently across a variety of environmental metrics, such as land use, impacts on water quality, or land conversion. The Federal Renewable Fuel Standard classifies both ethanol and biodiesel as renewable, so for the purposes of the CEP goal of meeting 90% of Vermont's energy needs with renewable sources by 2050, all liquid biofuels are considered renewable. Vermont should work at the federal level to make biofuels, especially ethanol, more sustainable by encouraging federal regulations to require increasing percentages of cellulosic and sugar-based ethanol.

12.4.2 State of the Market

National Production

Since the 2011 CEP, the market for biofuels has transformed from a local, small-scale phenomenon into a national commodity market. Driving this shift was the federal Renewable Fuel Standard. The original standard, passed in 2005, required that 7.5 billion gallons of ethanol be blended into transportation fuels by 2012. In 2007, the law was amended: it now includes biodiesel, adds different categories of biofuel, requires that renewable fuels emit less GHGs than fossil fuels, and requires that 36 billion gallons of renewable fuels be blended into transportation fuels in the U.S. by 2022. (See Exhibit 12-25.) The EPA adjusts these requirements periodically to reflect market conditions. For the most recent adjustment which was concluded in December 2015, see the EPA's Renewable Fuel Standard Program website.[375] The law requires refineries, blenders, and importers to either blend renewable fuels into the fuel they sell, or to buy Renewable Identification Numbers (RINs) from suppliers who are producing and selling biofuels themselves.

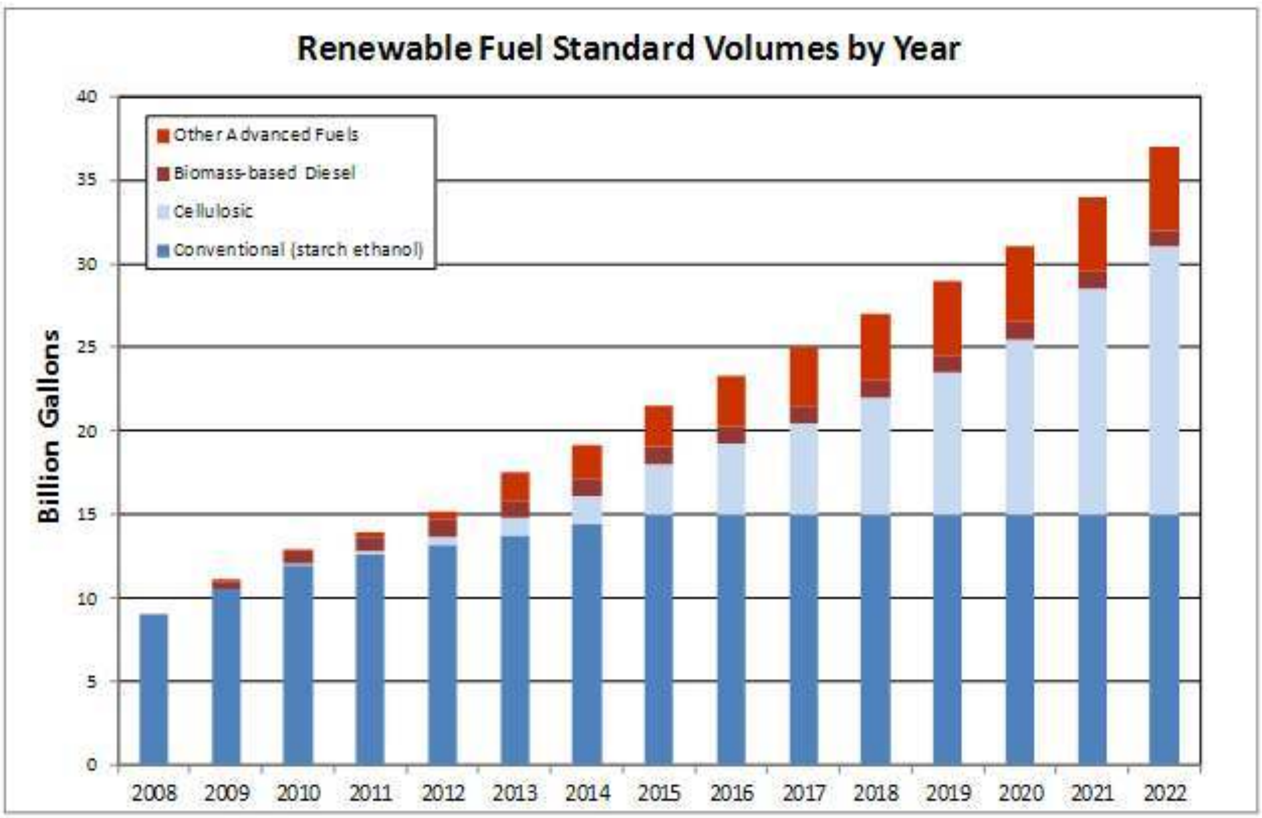
A federal $1 per gallon tax credit for biodiesel blending also provides a strong incentive for biodiesel production. The tax credit has been a source of uncertainty for biodiesel producers, going through frequent rounds of expiration and renewal; a stable, long-term federal tax credit would provide greater certainty to producers, and would be more effective at drawing producers into the market. The credit was renewed in December of 2015 to continue through 2016. In 2015, Congress also added a small agri-biodiesel producer tax credit of 10 cents per gallon.

375 http://www.epa.gov/renewable-fuel-standard-program

The national, annually increasing requirements in the Renewable Fuel Standard have stimulated investment in supply and delivery infrastructure for biofuels — including ethanol, usually derived from corn, and biodiesel, usually derived from oilseed crops. In the U.S. today, 95% of gasoline is already an E10 blend, meaning the nation is reaching the *blend wall* — the maximum amount of ethanol that can be added to gasoline without significant changes to the light-duty fleet. Future growth in the Renewable Fuel Standard targets cellulosic ethanol, biodiesel, and other advanced fuels, including fuel derived from algae.

If the Renewable Fuel Standard remains in effect, a robust national market will develop for biodiesel and cellulosic ethanol by 2022. Vermont is well positioned to benefit from this market, as the state has been actively incubating biodiesel production for over a decade. Biodiesel can now be easily obtained from most petroleum distribution hubs around the U.S. — including hubs at Albany, N.Y., Portsmouth, N.H., and Montreal that are used by Vermont wholesale and retail suppliers of petroleum products.

Exhibit 12-25. Federally Mandated Production of Renewable Fuels

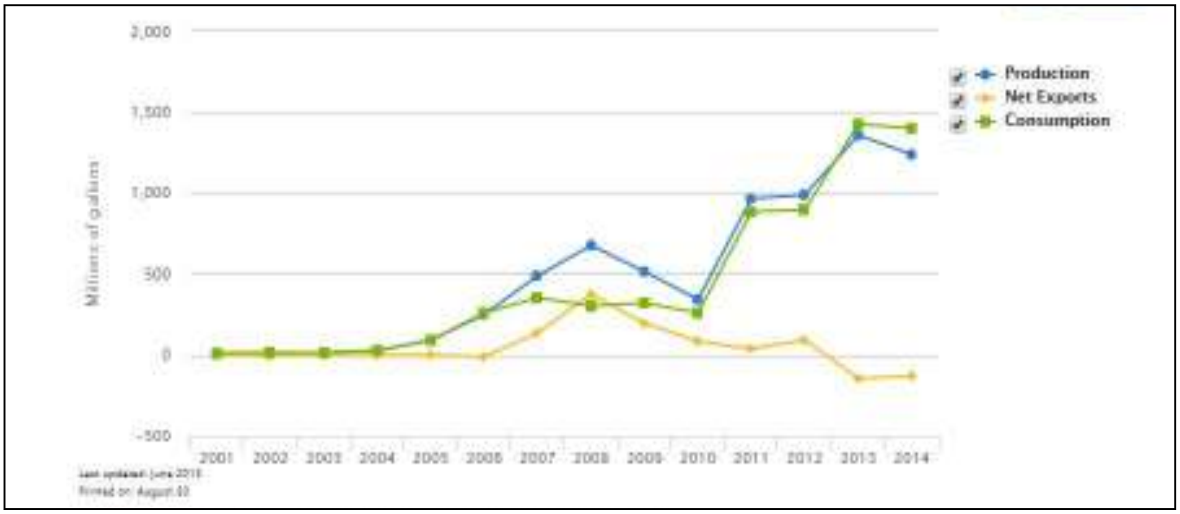


Source: EPA Alternative Fuels Data Center.[376]

[376] U.S. DOE, *Renewable Fuel Standard*, www.afdc.energy.gov/laws/RFS

Commercial sales of biodiesel greatly increased in 2005, when about 100 million gallons were produced in the United States. Production increased until 2008, when it fell slightly in response to the recession, then rebounded and rose to nearly 1.5 billion gallons in 2014. In response to continued interest in fuel security, the Obama administration announced a major initiative in August 2011 to spur the biofuels industry with an investment of up to $510 million during the following three years, in partnership with the private sector. The initiative responds to a directive that President Obama issued in March as part of the Blueprint for a Secure Energy Future, the administration's framework for reducing dependence on foreign oil.[377] More broadly, the Renewable Fuel Standard and the new research initiative have created a strong market for biodiesel in the U.S.

Exhibit 12-26.U.S. Biodiesel Production, Exports, and Consumption



Source: Alternative Fuels Data Center.[378]

<u>Production in Vermont</u>

The recent price drop for petroleum products has deeply influenced the economics of liquid-biofuel production in Vermont. At this writing, the cost of diesel fuel has dropped from roughly $4 per gallon in 2011 to $2.10-$3.00 per gallon, and some farmers who were producing biofuels have stopped. Others continue, motivated by the opportunity for fuel independence and the co-products of biofuel production. At the same time that biodiesel production has become less attractive for economic reasons, funding for inter-sectoral coordination efforts has also expired. A U.S. DOE grant that funded the Vermont

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[377] The White House, "President Obama Announces Major Initiative to Spur Biofuels Industry and Enhance America's Energy Security" (Office of the Press Secretary, August 16, 2011), www.whitehouse.gov/the-press-office/2011/08/16/president-obama-announces-major-initiative-spur-biofuels-industry-and-en

[378] U.S. DOE, *U.S. Biodiesel Production, Exports and Consumption* (Alternative Fuels Data Center, 2015), www.afdc.energy.gov/data/10325

Sustainable Jobs Fund's Vermont Bioenergy Initiative concluded, so ongoing coordination efforts have shifted to the Farm to Plate Energy Cross Cutting Team[379] and University of Vermont Extension[380].

The Vermont Bioenergy Initiative resulted in significant research and capacity-building among farmers in the state. The Initiative's website offers extensive technical resources to farmers and others interested in biofuel production.[381] There are ongoing research and educational efforts at UVM, especially in oilseed- and algae-to-biodiesel research.[382]

In recent demonstration projects, relatively moderate yields of Vermont-grown oilseeds and at small scales of production, farm-based biodiesel enterprises are producing fuel at a cost of $2.30-2.50 per gallon, with a net energy-return ratio of between 3.6 and 5.9 to 1, and with net carbon avoidance of 1,984 to 3,227 pounds per acre per year.[383] Despite these results and other benefits such as supply stability and resilience, adoption of farm-based biofuels has been slow and even declining in the face of relatively low petroleum prices.

Although dips in petroleum prices have made the economics of biodiesel production in Vermont less attractive, the state still has the opportunity to expand the production and use of agriculturally derived biofuel products to heat homes, offices, and commercial spaces, and for use in transportation and on farms. During the past 15 years, many Vermonters have worked to introduce liquid biofuel products and develop viable production systems that foster the emergence of new bioenergy technologies and markets. Many of these projects remain active because farmers are interested in environmental sustainability, energy independence, and building capacity for a time when diesel prices may rise.[384]

Several farms now produce their own fuel in Shaftsbury, Alburgh, North Hardwick, and Newbury. The sustainable production of bioenergy feedstocks and fuels is part of an integrated perspective of farm-based productivity that yields a variety of food, fiber, and fuel products for local use. Such strategies are consistent with the state's overall focus on retaining the working landscape, and with its commitment to small farmers.

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379 Farm to Plate, *Energy*, www.vtfarmtoplate.com/network/energy

380 www.uvm.edu/extension/cropsoil/oilseeds

381 Vermont Bioenergy Initiative, *vermontbioenergy.com/*

382 UVM Extension Agronomist Dr. Heather Darby and UVM Professor Dr. Anju Dahiya both run excellent research and education programs in bioenergy. Their websites are www.uvm.edu/extension/cropsoil/oilseeds and www.uvm.edu/~adahiya/.

383 Callahan, C. (*2015) On-Farm Biodiesel in Vermont: A Decade of Learning. (A Techno-Economic Model). 2015 ASABE Annual Meeting. New Orleans, LA.*

384 Recent data about the economics of biodiesel production on farms is available in *Vermont On-Farm Oilseed Enterprises: Production Capacity and Breakeven Economics* (Vt. Bioenergy Initiative, 2013, by Netaka White and Chris Callahan), vermontbioenergy.com/wp-content/uploads/2013/03/VT-Oilseed-Enterprises_July_2013.pdf

12.4.3 Resources

Vermont has the estimated potential to produce about 4 million gallons of B100 per year from in-state agriculture lands — an eightfold increase from the state's peak production in 2008.[385] If that number is realized, much of this fuel is likely to be used for off-road vehicles, including farm and construction equipment. To sell biodiesel for on-road use, Vermont producers would have to add significant additional technical capacity in order to register with the EPA as a biodiesel producer meeting ASTM requirements.[386]

With our long history as an agricultural state, Vermont has the opportunity to support farms that add bioenergy crops to their rotations. Within the state's total land area of 5.9 million acres, approximately 1.25 million acres (21%) are classified as farmland. Of those, approximately 536,052 acres are in cropland, and 446,020 acres are harvested.[387] This leaves approximately 90,032 acres of unused or underutilized cropland that is potentially available for biofuel production.

Assuming average yields, and the use of approximately 60,000 acres of the available land for oilseed production, an annual production of approximately four million gallons of biodiesel from crop-based feed stocks in Vermont is possible.[388] This would be enough to replace all distillate sold in Vermont, for both transportation and heating, with a 2% biodiesel (B2) blend. Even though is not likely that every unharvested acre could be economically harvested, or that all yield rates would be reached, these estimates suggests there is reason to be optimistic about Vermont's biofuel energy potential.

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[385] It is assumed in this estimation of Vermont's agricultural biofuels potential that land use patterns remain as they currently exist, that no deforestation occurs, and that current production rates of existing crops remain the same.

[386] Carla Santos, *On-farm Biodiesel Production in Vermont: Legal and Regulatory Overview*, Institute for Energy and the Environment, Vermont Law School (2015), vermontbioenergy.com/wp-content/uploads/2014/07/Legal-Regulatory-Review-of-On-farm-Biodiesel-Production_IEE_VSJF_2015.pdf

[387] USDA Census of Agriculture, *2012 Census Publications: Vermont*, www.agcensus.usda.gov/Publications/2012/Full_Report/Volume_1,_Chapter_1_State_Level/Vermont/st50_1_009_010.pdf

[388] This calculation uses Vermont 25 x '25 Initiative 2008 baseline assumptions, updated with current data from the 2007 Agriculture Census and VSJF.

Exhibit 12-27. Estimation of Agricultural Biofuels Potential in Vermont

	Yield (per Acre)		Btu/gallon	Acres	Energy Yield (Gallons)	Energy Yield (Billion Btu)
Oil Seed Crop	65	gal	130,000	61,000	4,000,000	520

Source: VSJF, updated Vermont 25 x '25 Initiative data

At a hypothetical farm producing 100,000 gallons of biodiesel per year, researchers at the Bioenergy Initiative estimated that the cost of production for biodiesel in Vermont was $2.13 per gallon.[389] With diesel selling at a record low of $2.66, there is currently a slim profit margin for oilseed biodiesel production.[390] If Vermont farmers could participate in the Federal Renewable Fuels market, where they could sell Renewable Identification Numbers and take advantage of a $1 per gallon blending tax credit, the economics of biodiesel production would become more attractive. Enrolling in these programs takes significant upfront investment and administrative capacity, so it may not make sense for relatively small-scale facilities. Ramping up production to meet more aggressive in-state production goals would require bringing more acres into production, although economic incentives for farmers to do so do not currently align.

Selling oil for consumption as food produces almost three times the profit as does processing it into biodiesel. Therefore, there is little financial incentive for farmers to use oilseed crops to produce biodiesel for sale in the market, although many continue to produce biodiesel for on-farm use.[391]

Developing the potential of algae-based biodiesel production is another promising area for in-state production. Burlington-based GSR Solutions is researching ways to use wastewater to grow oleaginous algae to produce biodiesel.[392] Algae production remains in the research stage, with full commercial production a number of years away. As diesel prices have dropped, the economic incentive to continue research and production has diminished — but it is important to continue support for research and development efforts, especially during times of low petroleum prices, because once the technology becomes scalable and economics align, algae could become an important source of renewable fuel in the future.

[389] Netaka White and Chris Callahan, *Vermont On-Farm Oilseed Enterprises: Production Capacity and Breakeven Economics* (Vt. Bioenergy Initiative, 2013), vermontbioenergy.com/wp-content/uploads/2013/03/VT-Oilseed-Enterprises_July_2013.pdf

[390] U.S. E.I.A., *Weekly Retail Gasoline and Diesel Prices*, *New England*, www.eia.gov/dnav/pet/pet_pri_gnd_dcus_r1x_w.htm

[391] White and Callahan

[392] More information about biodiesel produced from algae is available at vermontbioenergy.com/algae/.

Expanded Potential and New Sources of Biodiesel for Thermal Uses

To provide a cleaner-burning fuel and create a solution to the diminishing market share that the oil heat industry faces, a number of Vermont fuel dealers and the Northeast oil heating industry have embraced a biodiesel/ultra-low-sulfur heating-oil blend known by the trademarked name Bioheat. One dealer in Morrisville has installed state-of-the-art biodiesel blending equipment to offer customers a range of biodiesel and blends, with its biodiesel product coming from White Mountain Biodiesel in New Hampshire.

As demand and production increase, local fuel marketers have the capacity to expand the volume of biodiesel blends offered to Vermont customers. The state helped move in this direction with the passage of the Vermont Energy Act of 2011 (Act 47), which included a timeline and mechanism for a transition to a biodiesel-blended, ultra-low-sulfur heating oil.[393] However, the law contains a provision that it will go into effect only if Massachusetts, New York, and New Hampshire adopt requirements that are substantially similar to or more stringent than Vermont's content requirements. At this writing, those states have not done that, so Vermont's law has not gone into effect.

Bioheat is preferred to pure fossil-fuel heating oil; but because it is a blend of renewable and fossil sources, it is not a wholly renewable alternative. It should be used to supplement wood and electric heat pumps. Bioheat in home heating is expected to serve as a bridge fuel for individual systems, until they can be replaced by clean-burning wood and electric heat pumps.

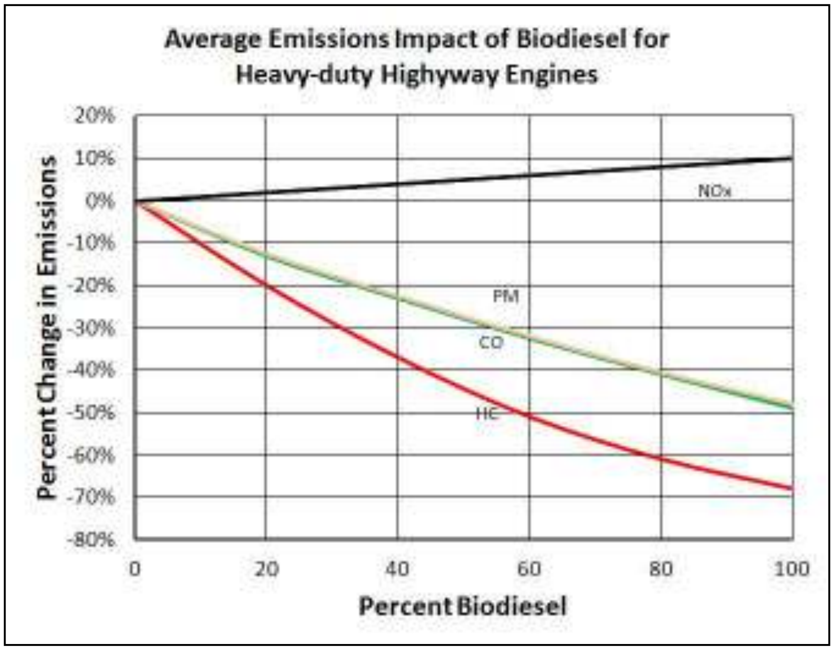
12.4.4 Benefits

Liquid biofuels, especially biodiesel, whether acquired in national commodity markets or procured from local sources, can offer a variety of benefits to Vermonters, including improved environmental performance, cost savings, and renewability.

The reduced pollution and GHG emissions from biodiesel (compared with using petroleum diesel) are well-documented, and the use of biodiesel as a fuel additive or a replacement for fossil fuels in transportation and heating applications is also well-established in Vermont. Numerous studies have concluded that biodiesel produces fewer atmospheric pollutants and has a low carbon intensity compared with petroleum diesel, resulting in lower GHG emissions both at the point of combustion and on a full life-cycle basis.

[393] 10 V.S.A. § 585

Exhibit 12-28. Average Emissions Impact of Biodiesel for Heavy-Duty Highway Engines.

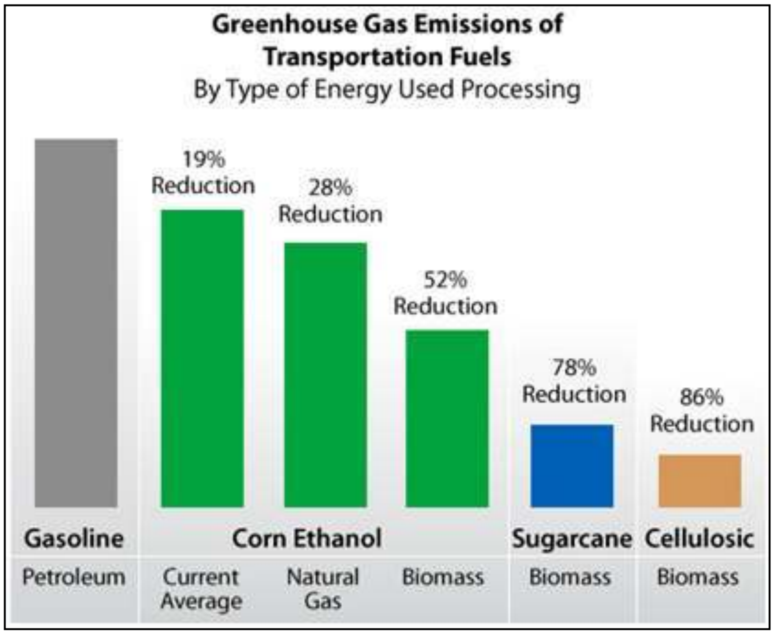


Source: US Department of Energy Alternative Fuel Data Center[394]

Ethanol, which is not generally produced in Vermont but is sold in the state through national commodity markets, is a renewable fuel that offers substantial air quality benefits. It performs less well than biodiesel in other environmental metrics, such as energy return on energy invested and land use/land conversion. (See exhibit 12-32).

394 U.S. EERA, *Biodiesel Vehicle Emissions*, www.afdc.energy.gov/vehicles/diesels_emissions.html

Exhibit 12-29. GHG Emissions of Ethanol Compared to Gasoline



Source: US Department of Energy Alternative Fuel Data Center

12.4.5 Challenges

Environmental Performance

Across a variety of metrics, environmental performance differs among different types of biofuels. As the industry has grown, so too has criticism of the broader environmental impacts of the production of biofuels, especially ethanol. Life-cycle analyses have shown that corn ethanol requires a large input of fossil fuel in the form of fertilizer, fuel for farm equipment, transport, and processing.

Studies show that ethanol yields between .84 and 1.65 units of energy for each unit of energy used to create it (energy return on energy invested, or EROEI). That means that in some cases it takes more energy to make ethanol than the ethanol yields. Cellulosic ethanol performs much better on this metric, with yields as high as 6.61 units of energy delivered for each unit of energy used to create it.[395] Biodiesel also performs better than corn ethanol on EROEI. Biodiesel in Vermont yields between 2.6 and 5.9 units of energy for each unit required to produce it.[396]

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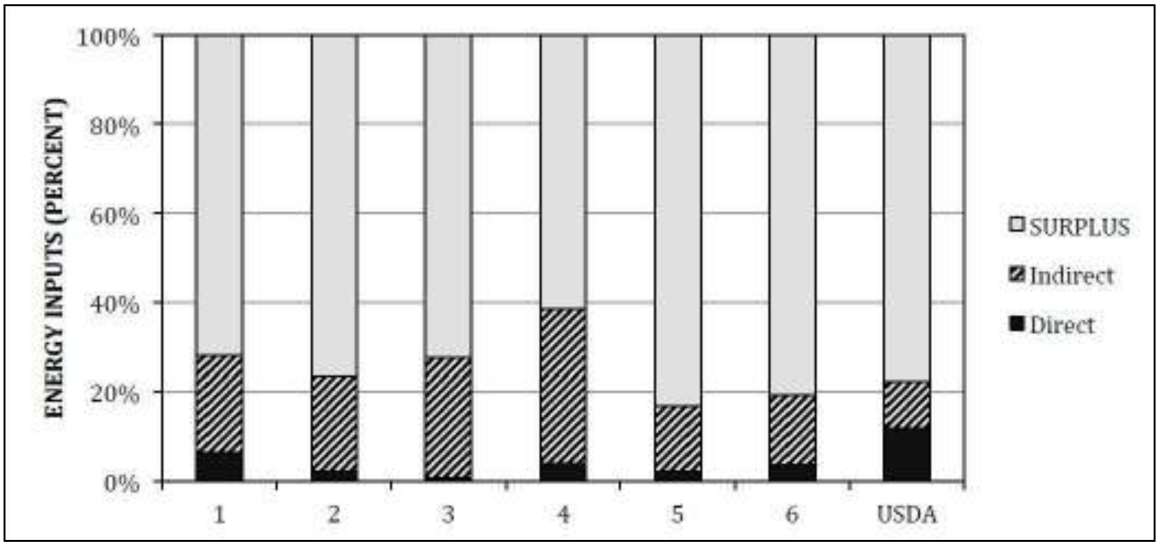
395 Roel Hammerschlag, "Ethanol's Energy Return on Investment: A Survey of the Literature 1990-Present," *Environmental Science and Technology* (2006, 40), pp. 1744-1750

396 Eric Garza, *The Energy Return on Invested of Biodiesel in Vermont* (Rubenstein School of Environment and Natural Resources, 2011), www.vsjf.org/assets/files/VBI/Oilseeds/VSJF_EROI_Report_Final.pdf

Exhibit 12-30. Energy Return on Energy Invested for Six Biodiesel Facilities in Vermont



Source: The Energy Return on Invested of Biodiesel in Vermont

Part of the public perception challenge facing biofuels, biodiesel in particular, stems from confusion over the differences between ethanol production and biodiesel production. Citing the relatively low to negative net energy balance for ethanol — the so-called *energy in, energy out* balance — critics of ethanol claim that biofuels in general yield low energy balances, and question the development of biofuels in general to save energy. To continue advancing, biodiesel must overcome this perception.

Increases in biofuel consumption can drive up demand for energy crops, along with the prices for those crops connected to international commodity markets. This can lead to both positive and negative changes in the U.S. and global economy. On the one hand, many farmers who are equipped to grow energy crops receive a steady demand for their products, and local economies benefit from the boost to the farm industry; on the other, an increase in crop prices can have an impact on the cost of food and can create pressure on farmers, especially in economically unstable countries, to clear more forested land to produce energy crops.

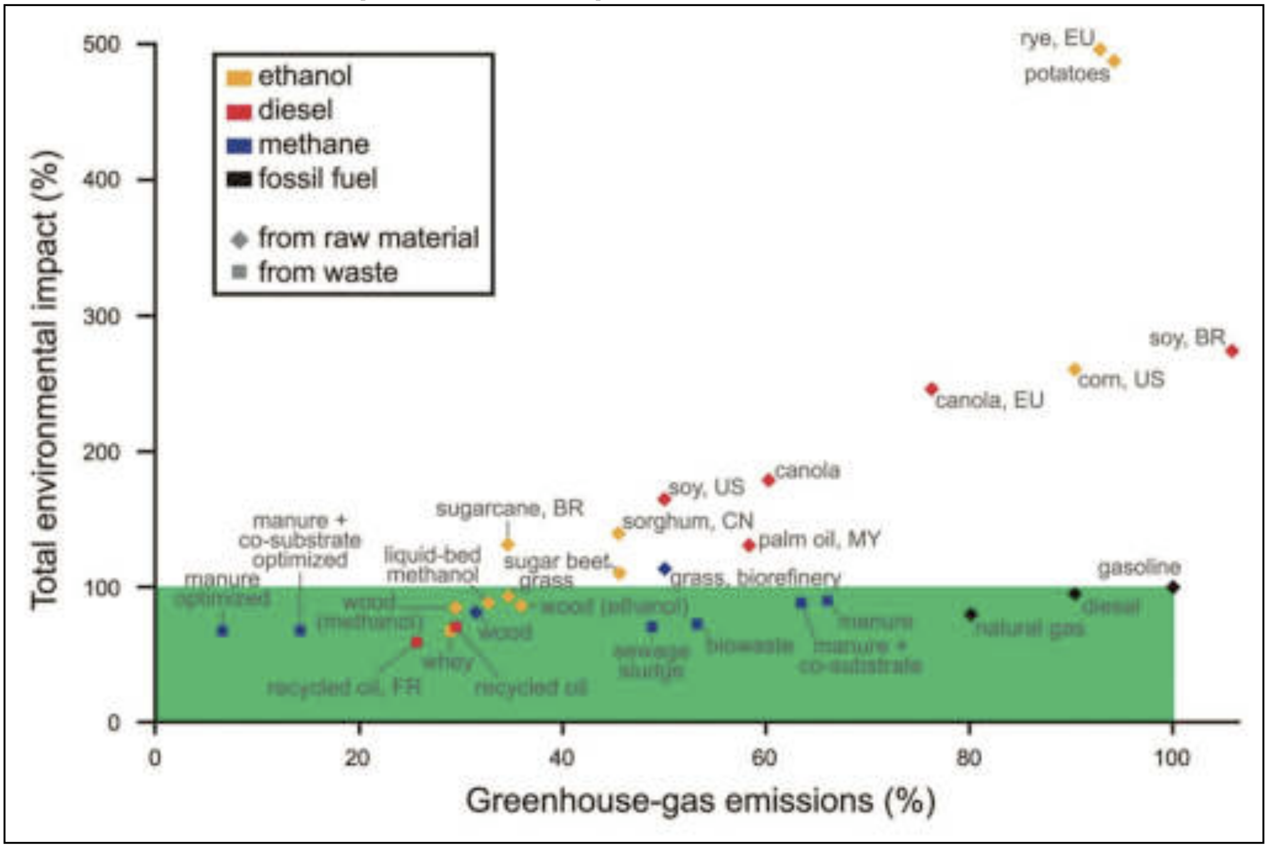
Obtaining biofuels from sustainably grown crops is an important issue that policymakers need to take into consideration. Although biofuels can help Vermont move toward clean energy goals and reduce the negative impact that energy consumption has on the environment, policymakers should be aware of all the consequences of biofuel policies as they work toward ensuring a sustainably produced biofuel supply for Vermont consumers.

Starch ethanol is also land-intensive, and may displace the production of food crops or cause land conversion from wilderness areas to farmland.

A study of the environmental impacts of various biofuels created a single combined metric to measure impact on ecosystems, soils, human health, and land conversion, and then compared that metric with the

GHG emissions savings over gasoline and diesel. Results showed that many biofuels, especially advanced biofuels created from waste products, outperform gasoline and diesel on GHG emissions as well as the other environmental indicators. Unfortunately, corn ethanol, the most commonly consumed biofuel in the state of Vermont, provides only marginal GHG savings and has a significant environmental impact in other areas.[397]

Exhibit 12-31. Environmental Impact of Biofuels Compared to Gasoline and Diesel



Source: Zah et. al.

All energy choices have environmental impacts — but the impacts of biofuels can be reduced by choosing better feedstocks, growing them on marginal farmland, and sourcing locally. Vermont can work at the national and local levels to improve the sustainability of these fuels. *Sustainability* here refers to best management practices that do not exceed the long-term productive capacity of the land base, and that protect and enhance biodiversity, soil, air, and water quality.

Availability and Clear Labeling

A survey conducted for the Vermont Sustainable Jobs Fund found that seven of 18 commercial end users had used biodiesel in the past but were no longer doing so. The reasons they gave included biodiesel price premiums, technical difficulties, erratic availability, and inconvenient use. Some former users said

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[397] *R. Zah et al,* Ökobilanz von Energieprodukten: Ökologische Bewertung von Biotreibstoffen (Empa, St. Gallen, Switzerland, 2007). www.news.admin.ch/NSBSubscriber/message/attachments/8514.pdf. (Although the study is presented in German, an English summary appears on page 7.)

they would return to biodiesel under certain circumstances — such as availability of biodiesel at a price on par with (or lower than) straight diesel; assurance that technical problems could be addressed; reliable supply, including automatic delivery; and improved on-site fuel storage and refueling infrastructure in the state.[398]

Under the Renewable Fuel Standard and the current specifications in the ASTM, wholesale dealers of diesel fuel are not required to report the blend they are using to retail purchasers if that blend is B5 or below.[399] Wholesalers of no. 2 heating oil are not required to report the biodiesel content of the fuel they sell, so long as it is B20 or below. As a result, it is very likely that much of the diesel and heating oil sold in Vermont contains some percentage of biodiesel, but neither fuel dealers nor the state can track how much. Wholesale suppliers that sell to Vermont retail dealers do not know the blend of biodiesel that they receive because upstream suppliers are not required to disclose that information. Any efforts to improve reporting will need to come from the national level, because most blending happens at refineries.

Equipment manufacturers, fuel dealers, and users would all benefit from knowing the exact biodiesel blend they are receiving. The problem has been discussed nationally for several years, but remains unresolved. There may be some inexpensive and feasible research methods for discovering how much biodiesel is being sold in Vermont, using a combination of market pricing data and hand-held fuel analyzers. It may be worth undertaking a study to determine how much biodiesel is being sold in the state, although this would not help retailers disclose to individual customers the blend they are receiving.

Challenges to Fostering Local Production

Small-scale biodiesel production methods are well established in Vermont and the state has many successful producers, although there are no commercial-scale production facilities. For local producers to ramp up production to a scale that could significantly affect Vermont's GHG emissions, and to market biodiesel for on-road use, they would be required to meet ASTM specification — which poses a significant barrier. Registering for participation in the Renewable Fuel Standards program to receive RINs, and registering as a blender to receive the $1 per gallon tax credit, would improve the economics of local biodiesel production, but would require a substantial investment of time and energy that may not be feasible or desirable for many farmers.

Part of the challenge facing Vermont bioenergy developers is that the model employed here differs from traditional commodity-scaled systems funded elsewhere. Even when biodiesel itself is uneconomical to produce, there may be interest on the part of farmers when oilseed biodiesel production is part of a larger, integrated farm plan that includes oilseeds providing fuel, feed, food, and revenue.

The model for producing biofuels elsewhere is not as sustainable as the model for producing biofuels in Vermont. Environmental concerns such as forestland conversion for palm oil plantations and fuels with a

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[398] Vermont Biodiesel Supply Chain Survey, p. 7

[399] Ron Korba, "Testimony from Congressional Hearing on Biodiesel RIN Fraud," *Biodiesel* Magazine (July 11, 2012), www.biodieselmagazine.com/blog/article/2012/07/testimony-from-congressional-hearing-on-biodiesel-rin-fraud

negative energy-return-on-energy-invested ratio (such as some forms of ethanol) have rightfully raised public skepticism about the sustainability of liquid biofuels. The Vermont model of production is radically different. It focuses on small-scale production on marginal farmland, coupled with the production of other resource streams such as animal feed. This model is more sustainable, although may not be able to provide the scale of fuel needed to meet Vermont's renewable transportation goals.

Strategies and Recommendations

Strategy 1: Improve the environmental and economic performance of liquid biofuels.

Recommendations

(1) *The state should work with federal partners to support federal policy changes that increase the sustainability of biofuels by increasing the volume of advanced biofuels, especially cellulosic ethanol and algal biodiesel, and instituting national sustainability standards for corn ethanol.*

(2) *Public and private stakeholders should continue to develop a sustainable biofuels industry in Vermont to enable the production and use of biofuels for transportation, agricultural, and thermal applications.*

Strategy 2: Increase the use of biodiesel in transportation and heating.

Recommendations

1) *The DPS should investigate methods for determining the biodiesel content of home heating oil and diesel in the state. If low-cost, feasible methods exist, the DPS should determine how much biodiesel is being used and report this information to the public, and help facilitate reporting for heating fuel and transportation retailers who wish to market their products as partially renewable.*

2) *The DPS should study the biodiesel market to consider whether there is sufficient supply, price impacts to consumers, and the potential blending regulations to mitigate the negative effects of biodiesel on equipment in a cold climate. Once this study is complete, the DPS should use the results to determine whether it is feasible and cost-effective for the state to require a 20% biodiesel blend in home heating oil and a 5% biodiesel blend in diesel transportation fuel.*

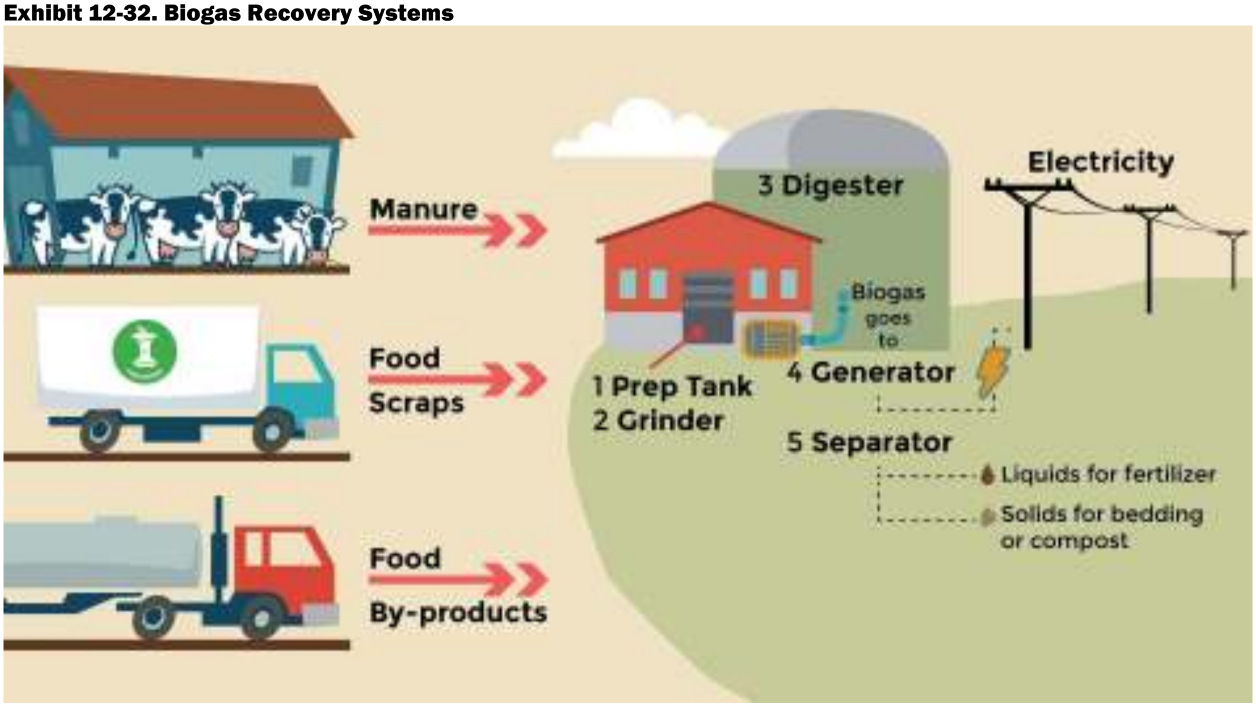
12.5 Biogas: Farm, Non-Farm, and Landfill Methane

12.5.1 Farm Waste Digesters

Manure has traditionally been stored in storage lagoons, where it produces odors and methane that escapes into the air. *Biogas* systems capture and harness the methane.

Farm waste digesters are systems that employ anaerobic digestion to produce methane, which is used to run combustion engines that produce heat and power. In a typical Vermont system, manure and other farm waste are kept warm in a closed tank for three weeks. Exhibit 12-32 shows a simplified diagram of the process.

Exhibit 12-32. Biogas Recovery Systems



Source: Vermont Sustainable Jobs Fund

12.5.1.1 State of the Market

Thanks to the combined efforts of farmers and their partners, Vermont farms have emerged as leaders in the field of farm methane-digester development. As of July 2015, there were 17 systems operating in the state, with an installed capacity of about 5.6 MW. (Exhibit 12-33 shows the list of operating systems.) Of the 19 states with a significant cow population, on a per-cow basis Vermont has double the number of digesters than the next leading dairy state, Pennsylvania. On a per-capita basis, Vermont has quadruple the number of manure digesters than the next leading dairy state, Wisconsin.[400]

Since the 2011 CEP, Vermont's fleet of farm methane systems has more than doubled — and estimated electricity produced has almost doubled, to approximately 22 million kWh.[401] Exhibit 12-33 shows the kW capacity of the 17 operating systems.

Exhibit 12-33. Operating Farm Methane Generators in Vermont

Farm	Size (kW)
Blue Spruce Farm	680
Chaput Family Farms	300
Dubois Farm	450
Four Hills Farm	450
Gebbie's Maplehurst Farm	150
Gervais Family Farm	400
Green Mountain Dairy	600
Joneslan Farm	65
Kane's Scenic River Farms	225
Keewaydin Farm	20
Maxwell's Neighborhood Farm	225
Monument Farms	150
Nelson Boys Dairy	300
Pleasant Valley Farms	600
Riverview Farm	180
Vermont Technical College	375
Westminster Farms	450
Total	***5,620***

400 Here, *significant cow population* and *dairy state* both refer to a state with more than 100,000 milk cows. By this definition, of the 48 states with cows in USDA's census, 19 are dairy states. Total U.S. cows are 9.25 million. Dairy states account for 88% of all those cows. The median number of cows in the 48 states is 85,000, and the average is 192,700 cows. Sources: USDA 2012 census for milk-cow numbers by state, and the EPA AgSTAR database of digester projects.

401 From Green Mountain Power's internal accounting, as presented to the Renewable Development Fund.

The DPS and the Vermont Agency of Agriculture, Food & Markets (VAAFM), with assistance from federal agencies such as the USDA, have partnered to promote utilization of manure as an energy resource to capture both public and private benefits. Through the efforts of these agencies and their partners, farmers are beginning to appreciate the potential of this resource.

Over the past decade, Vermont has taken the lead in helping farmers achieve manure management goals, decrease their energy purchases, and gain an additional source of income. Incentives for farm biogas-production facilities have been made available through programs like GMP's Cow Power, the state's Clean Energy Development Fund, and the USDA.

In 2009, the advent of the Standard Offer Program created more opportunities for farm methane producers to generate sufficient revenues to become viable. At the end of 2013, farm methane projects were producing more electricity than the solar projects in the Standard Offer Program.

Standard Offer prices are periodically adjusted, and the most recent prices offered for farm methane projects are $0.145 per kWh fixed over the 20-year contract for projects with a nameplate capacity greater than 150 kW. Over the last five years, digester-design companies have created designs for smaller systems. In April 2015, after considering Vermont's existing digesters and their costs, together with calculations based on costs of proposed projects, the PSB established a higher rate for smaller projects.[402] The new rate of 19.9 cents per kWh, for projects of 150 kW or fewer, could lead to farms with 500-600 cows installing a digester.

In 2010, the Legislature allowed existing farm methane projects into the Standard Offer program, and released all farm methane projects from the Standard Offer's kW capacity cap. This now allows existing farm methane generators to obtain Standard Offer price contracts without having to go through the auction process.

Eight of the 17 farmers who operate digesters in Vermont add some food-processing residuals, such as whey from cheese making, to increase the energy output of their system. They all use the separated solid residuals from the digester for animal bedding (studies have shown that the material is safe for this use). ANR and VAAFM cooperate with the farms to determine whether the digester feedstock materials proposed are appropriate for land application after digesting, and if the farm has enough winter storage capacity, even with the new materials added.

With a history of early attempts going back to 1982; the introduction of the Cow Power program, a green pricing program created by Central Vermont Public Service in 2005; and the consistent support of Green Mountain Power's Renewable Development Fund and the Clean Energy Development Fund, dairy farmers have built 16 systems that are now generating electricity.

Two additional anaerobic digester manure methane projects that would be owned by non-farmers and co-located on farms are proceeding to permitting and are expected to be operational in 2017. These differ

[402] PSB Order re: 2015 Standard-Offer Prices for Farm Methane Projects, in dockets 7873 and 7874. April 2, 2015.

in key respects, and would be the first such projects in Vermont. Green Mountain Power is proposing to build a three-farm digester in St. Albans Town, two and a half miles from St. Albans Bay. The project would produce electricity, with a capacity of 450 kW, using manure from three farms and approximately 2,000 cows. Two of the farms adjoin the site and would deliver manure by pipe, and receive liquid from the digester by pipe as well. The other farm would use trucks.

In Salisbury, Lincoln Renewable Natural Gas, LLC proposes to build a three-tank, 1.3-million-gallon digester that includes equipment to purify the biogas for use in a pipeline, and has a long-term agreement to sell the gas to Middlebury College. The project incorporates manure from three farms, totaling 2,400 cows. On average, the digester and the gas-upgrading equipment will deliver 130 scfm of pure renewable methane gas to the pipeline.

Digesters can also be designed to run primarily on materials other than manure. These *mixed-substrate* anaerobic digesters can utilize inputs as varied as livestock manure, crops harvested as silage, food scraps, and other agricultural waste products. The biogas yields per ton of certain crops and food wastes are much higher than from cow manure. If these wastes were readily available, and the output of the digester were shown to be safe, Vermont's potential electric capacity from farm-based digesters could be doubled from 15 MW to 30 MW.[403]

On a trial basis, two farms will be taking food scraps (considered solid waste) and testing the resulting digested manure residuals for suitability as bedding. The food scraps will be ground into slurry, away from the farm, and then injected into the digester using the same reception pit as the farms employ to receive food-processing residuals, such as whey from a creamery.

Vermont Technical College has been putting grease-trap waste, a mixture of fats, grease, water, and some bits of food that is diverted from kitchen sink drains in restaurants to prevent clogging in downstream pipes, into its digester. The energy potential from grease-trap waste is ten-fold or more of that from manure.[404][405] Likewise, Vermont Technical College has also added glycerin, a byproduct from biodiesel manufacturing, in its digester. Like grease-trap waste, glycerin provides an energy boost compared to manure.[406]

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403 As a rule of thumb, five cows provide enough manure for one kilowatt of engine-generator capacity. Vermont has about 135,000 cows. Thus, if manure from 75,000 cows were going through a digester, this amounts to 15 MW of potential electrical capacity. By adding food wastes or purpose-grown crops to a digester, production can be doubled or tripled.

404 *Manure Characteristics* (2004), MidWest Plan Service, MWPS-18 Section 1, Second Edition

405 *Septage and Restaurant Grease Trap Waste Management Guidelines* (2015), Minnesota Pollution Control Agency, www.pca.state.mn.us/index.php/view-document.html?gid=10136

406 *Utilization of Biodiesel By-Products for Biogas Production* (2011), Journal of Biomedicine and Biotechnology. www.hindawi.com/journals/bmri/2011/126798/, and "Generation of biogas using crude glycerin from biodiesel production as a supplement to cattle slurry" (2010), *Biomass and Bioenergy*, Volume 34, Issue 9.

Vermont has one trial project to grow algae using the liquid digestate outflow of the digester. The algae can then be harvested for oil or other uses.

12.5.1.2 Resources

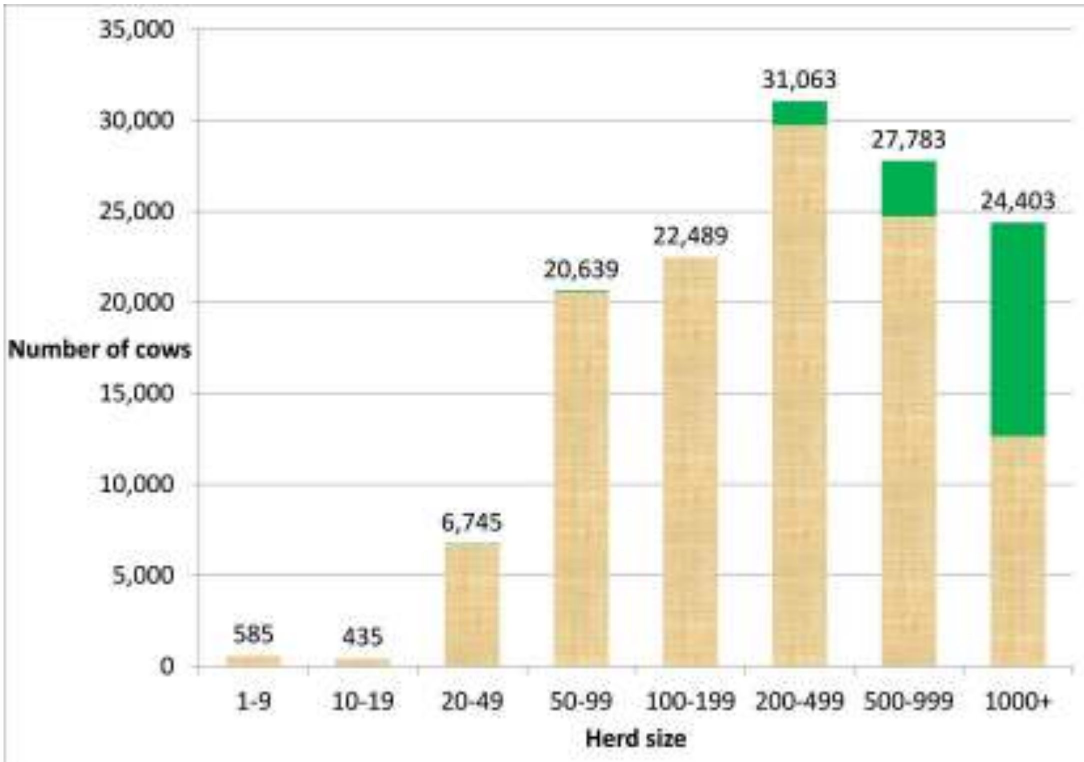
As of 2015, Vermont has about 870 dairy farms milking a total of about 134,000 cows.[407] The cows are housed in a variety of barn types and are managed in a wide variety of ways. Some farmers pasture their cattle, while others house them, at least the cows and calves, year-round.

For the 2009 Vermont 25 x ’25 Initiative report, the VAAFM estimated that about one-half of the manure in the state would be available for digestion. VAAFM estimates that this would give a total installed electric generation capacity from manure of 15 MW, producing about 90 million kWh of electricity annually.

Most of Vermont’s dairy farm manure is generated on farms with fewer than 500 cows. Only about 10% of the dairy farm manure from the roughly 134,000 dairy cows in Vermont is going through a digester as is shown in Exhibit 12-37.

[407] Vermont Dairy Promotion Council, *Milk Matters: The Role of Dairy in Vermont* (with VAFM and VCCD), vermontdairy.com/download/VTDairy_MilkMattersReport.pdf.

Exhibit 12-34. Vermont Dairy Herd Sizes
Note: Green corresponds to cows in those herd sizes whose manure is being digested.
Note that herd size doubles from each category to the next.



Sources: EPA AgSTAR database (June 2015) and USDA Census (2012)

12.5.1.3 Siting and Permitting

Farm methane projects that produce power to the electric grid are required to obtain a Certificate of Public Good from the PSB. In Act 88 of 2014, the PSB's jurisdiction over farm methane projects was explicitly narrowed to the electric-generation aspects of the project, while permitting for food-processing residuals continues to be permitted through ANR's Solid Waste Division. Air pollution emissions from digesters and gas-fired generators are subject to permit/approval, and to annual emission reporting, through ANR's Air Quality and Climate Division. The VAAFM retains jurisdiction on manure management.

12.5.1.4 Benefits

The anaerobic digestion process destroys pathogens, reduces odors, changes the form of agronomic nutrients, and yields a gas mixture of methane and carbon dioxide. The volume of manure remains essentially constant. In addition, the nutrients from the manure remain in the material that is extracted from the digester, making these nutrients more readily available to plants, and more precisely applied for improved crop production.

Biogas from a digester consists of 45% carbon dioxide and 55% methane, along with small amounts of other gases. The GHG value of methane in the atmosphere, over a 100-year time horizon, is 25 times that of carbon dioxide — so any system that captures methane from manure and burns it, converting it to carbon dioxide, significantly reduces GHG emissions. Also, the power produced offsets power produced from other sources that may also have generated GHG emissions.

In addition to the GHG benefits, capitalizing on farm energy resources diversifies sources of revenue and can improve the bottom line for Vermont's agricultural enterprises. Benefits extend beyond the farm to the public, by providing additional renewable baseload power to the grid, along with a range of environmental benefits, from odor amelioration to GHG reduction.

An additional by-product of the process is the solids. This bacteria-reduced material can be used as bedding material for cows, replacing the need for sawdust, or it can be used as a soil amendment.

Whether or not a digester is owned by a farmer, the owner can take advantage of products other than electricity to generate income or save money in new ways, such as operating a greenhouse using extra heat from the engine[408], composting extra solids from the digester for sale, or applying liquids from the digester using a dragline system.

12.5.1.5 Challenges

Even with the large untapped potential and all the benefits of farm methane projects, project development has stalled. As of late 2015, no farmer is building a digester, nor have any farms committed to building one.

Vermont draws social and economic benefits from its working agricultural sector. While dairy farming and dairy processing provide 70% of Vermont's agricultural sales, milk prices are volatile and cash flow can be very uncertain.[409] Developing a new methane digester is a long and costly process. Challenges include gaining access to the three-phase power needed to support and transmit power from the systems; earning sufficient revenues (or generating enough savings, in the case of net metering) from the electricity; and accessing capital. Despite Vermont's track record and improvements in each area since 2012, these all remain difficult barriers.

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408 See, for example, Alex DePillis, *Digester on a Dairy Farm,* Vermont Agency of Agriculture, Food & Markets, www.vtfarmtoplate.com/assets/resources/files/6_Digester%20on%20a%20Dairy%20Farm_Maxwells%20Neighborhood%20Farm_Final.pdf

409 Dairy farmers endured an average milk price of $13.82 per hundred pounds of milk for 2009, followed by four years of prices at or near $20. Finally, 2014 brought an average price of over $25 per hundred pounds (future.aae.wisc.edu/data/annual_values/by_area/10?area=VERMONT). By August of 2015, prices plunged far enough that farmers diverted milk to the manure pit rather than lose money by shipping it (vtdigger.org/2015/07/09/glut-of-milk-leads-vermont-farms-co-ops-to-dump-product). Prices for 2016 are projected as $16.40 per hundred pounds (www.ers.usda.gov/publications/ldpm-livestock,-dairy,-and-poultry-outlook/ldpm-254.aspx, *www.ers.usda.gov/media/1885180/dairy-forecasts-august-2015.xlsx*).

Despite the GHG benefits outlined in the previous section, farm methane and other biogas digesters with electric generators emit substantial quantities of criteria air pollutants and air toxins, including sulfur dioxide, carbon monoxide, hydrogen sulfide, and formaldehyde.

Given the substantial initial capital required for a methane digester, and the extended project-development period of up to four years, access to grant funding has proven essential to covering costs for such expenses as planning, engineering, and connecting to three-phase power. However, there are now fewer grant opportunities than when most of Vermont's existing farm digesters were built. This has made it a challenge for new projects to move forward.

Similarly, access to low-cost credit from organizations such as CEDF and VEDA's Agricultural Credit Corporation has been instrumental to the success of farm digesters. Farms generally have to mortgage their farm to develop a digester, because lenders often will not take the digester as collateral.

Finally, a range of specific challenges has emerged for system farmers/operators. These include:

- Equipment failures in some cases, due to flawed design, sometimes accompanied by weak customer support from undercapitalized and immature equipment providers.
- Persistent issues at most projects from corrosion and/or fouling, caused by hydrogen sulfide gas.
- Additional labor demands on farmers, especially if they want to fully utilize co-products, such as running a greenhouse to use the heat, or to set up a compost operation to increase the value of the solids.
- Environmental permitting for inputs that spans several divisions of the ANR and several types of permits, depending on the material.
- Failure to fully consider various state fees, such as the air emission fees, in operational costs.

Recommendations

(1) Develop support from Vermont state agencies, departments, and electric utilities for the development of farm biogas recovery systems through incentives, education, and outreach programs.

(2) Work with federal partners for continuation of NRCS and USDA REAP grants for on-farm bio-digesters.

(3) Revise ANR's solid waste rule to include existing and new farm digesters as a safe and cost-effective pathway for the approximately 30,000 near-term tons of food waste per year that will be diverted from landfills. Clarify permitting and revise rules if necessary, to safely use grease-trap waste and glycerin from biodiesel processing in farm digesters.

(4) *Coordinate, via regularly scheduled meetings between ANR, DPS, and VAAFM staff, to better cooperate and align state activities related to anaerobic digestion and to facilitate the sharing of information across all AD sectors: farms, food-processing industry, and wastewater treatment.*

(5) *Convene the relevant state agencies and VGS personnel to review progress on increasing the fraction of renewable natural gas in VGS system.*

12.5.2 Non-Farm Anaerobic Digesters

The anaerobic digestion of organic waste can also be used in non-farm applications, either employing non-farm organic waste material or combining farm waste material with non-farm material.

12.5.2.1 State of the Market

Non-farm digesters are most commonly found at food-processing facilities and municipal waste facilities that have both large quantities of organic waste material and a need for heat and electricity. In 2010, Purpose Energy installed an anaerobic digester at the Magic Hat Brewery in South Burlington to provide heat for brewing, to power the facility, and to reduce the biological oxygen demand (BOD) of Magic Hat's liquid waste stream.

Brattleboro, Montpelier, Essex Junction, and other municipalities have anaerobic digesters that are part of their municipal waste systems and provide those facilities with heat and power. These systems anaerobically decompose the wastewater treatment plant solids, reducing BOD, while generating methane that is then combusted for energy recovery.

ANR's Wastewater Program, in the Watershed Management Division of the Department of Environmental Conservation, surveyed 10 wastewater treatment facilities. The responses indicated that, among the 23 digesters at these facilities, only a minority of the digesters are sending the biogas to be burned for energy.

Vermont has approximately 90 municipally operated wastewater treatment facilities. Thirty are above the permitting threshold of processing one million gallons per day or serving a population of at least 10,000. There are also about 60 private or institutionally operated systems. A quick calculation shows that facilities serving 10,000 or more people have the potential to reduce their electricity costs by about one quarter if they employed energy recovery from the digester.

Act 148 institutes a ban on disposal of food residuals for all waste generators, including residential generators, to be enforced by 2020. It also mandates that solid waste processers offer services for processing food residuals by 2017, and that haulers must offer curbside collection of food residuals by 2017. Among the many possible pathways, food waste could be processed together with sewage.

12.5.2.2 Siting and Permitting

Section 248 applies to anaerobic-digester projects at any municipal (or other) wastewater treatment facility that would involve electricity generation. No additional permits are necessary from the Wastewater Program, nor does the program require permits for the heat-recovery aspects of operating a digester. However, as with any stationary source of air emissions, any boiler or engine-generator may be subject to air emission fees, depending on the amount of emissions.

12.5.2.3 Benefits

Wastewater treatment plants need a lot of electricity. In 2008, the most recent year for which data are available, Efficiency Vermont calculated that Vermont's 97 municipal water resource recovery facilities used 33,461 MWh of electricity, or about 0.6% of the state's total electric use.[410] Facilities that process over five million gallons per day commonly use anaerobic digestion to process the solids found in wastewater. The resulting biogas is used in a combined heat and power system to offset energy needs at the facility. In addition to the energy generation potential from biogas, anaerobic digestion cuts the volume of solids by half and destroys pathogens.[411] All of Vermont's treatment plants are considered small by national standards, with approximately 8-10 facilities large enough to support anaerobic digestion and only 4-5 large enough to economically produce energy from digester gas.

Using EPA generalizations of 1,200 kWh to process one million gallons of wastewater per day, and a city of 10,000 requiring this size of facility, a city the size of Milton would use more than 400,000 kWh per year, at a cost of more than $50,000, to treat its wastewater.[412] Based on the experience at Essex Junction's wastewater treatment facility, such a city could save $10,000 on electricity, and perhaps a similar amount in heat, if it installed a system that generated electricity and captured some of the heat from the engine coolant and the exhaust gases.

12.5.2.4 Challenges

As at a dairy farm, waste management and processing at a wastewater treatment facility is complex and entails multiple control points and points of potential failure. Good operators, whether they operate a dairy farm or a wastewater treatment facility, are justifiably wary of putting a known and good outcome at risk by adding complexity to their operation. Although the probability of a failure may be low, the consequences can be dire — fish kills, public health problems, and fines.

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[410] *Aggregation of Efficiency Vermont's confidential data.*

[411] *Electricity Use and Management in the Municipal Water Supply and Wastewater Industries* (2013), Electric Power Research Institute and the Water Research Foundation. http://www.waterrf.org/PublicReportLibrary/4454.pdf

[412] U.S. EPA, *Clean Energy Opportunities in Water & Wastewater Treatment Facilities: Background and Resources* (2009), www.epa.gov/statelocalclimate/documents/pdf/background_paper_wastewater_1-15-2009.pdf

Unless there is a compelling case, financially or operationally or both, to advance a biogas-utilization project at a wastewater treatment facility, avoiding risk and sticking with the status quo will win.

Recommendations

(1) Support and encourage municipalities that are remodeling their waste treatment facilities to include anaerobic digestion with methane capture as part of their treatment systems.

(2) Investigate the solid waste permitting process and how it relates to farm digesters, and recommend changes to the permitting process, especially for the hauling and handling of material headed to and coming out of anaerobic digesters.

(3) Convene staff from ANR, DPS, and VAAFM to coordinate, cooperate, and align state activities related to anaerobic digestion and to facilitate the sharing of information across all AD sectors: farms, food-processing industry, and wastewater treatment.

12.5.3 Landfill Methane

As refuse decomposes in landfills, methane gas is released, eventually rising to the atmosphere. Landfills can control this flammable gas by collecting it via pipelines buried in the landfill, and may use it as a fuel to generate electricity and heat.

12.5.3.1 Resource and State of the Market

Vermont currently has a small number of landfill biogas generation facilities, with operations in Coventry (8 MW), Moretown (3.2 MW), Burlington's Intervale (rated at 350 kW but producing at an estimated 60kW), and Williston Gas Watt Energy (90 kW).

The Brattleboro landfill also has a project (about 300 kW of capacity but generating less) that was re-started in 2010. Although it has not been producing power continuously, the project was recently purchased by Brattleboro Organic Energy LLC, which is looking to keep the landfill gas generator operational and to co-locate a food-waste digester at the site.

Landfill methane projects can qualify for Standard Offer contracts at a 20-year levelized price of $0.09/kWh — or they can net meter, which is what the Burlington Intervale system is doing.

With only one landfill in the state (Coventry) still receiving waste material, and other landfills either already developed or not viable for gas-to-energy projects, the outlook for landfill gas-to-energy in Vermont is that any new capacity will be offset over time with a decrease in methane from landfills that are closed.

12.5.3.2 Siting and Permitting

Increased awareness of the environmental problems caused by landfills has made permitting for them much more stringent, resulting in all but one landfill in Vermont still being able to accept new material. Any closed landfills that are viable for the collection of the methane and have access to necessary electric distribution lines should not have difficulty obtaining a CPG for a gas-to-energy project.

12.5.3.3 Benefits

In addition to the renewable energy generated, destruction of the methane has great GHG reduction benefits, as methane is a potent contributor to climate change. The projects also can provide revenue that can help cover a landfill's long-term environmental maintenance costs.

12.5.3.4 Challenges

Act 148 creates a ban, to be enforced by 2020, on disposal of food residuals for all waste generators, including residential generators. It also mandates that solid waste processers offer services for processing food residuals by 2017, and that trash haulers must offer curbside collection of food residuals by 2017. This will result in less food waste being deposited in Vermont's remaining landfills, which will then produce less methane from which power can be generated.

12.5.4 Other Biogas

In addition to anaerobic digesters and landfill methane, other sources of biogas may emerge in the future. For example, projects in other states have attempted to commercialize gasification or pyrolysis of solid waste. Should such a technology prove effective, environmentally sound, and otherwise viable for Vermont's organic waste, Vermont should revisit the use of such waste as a fuel for renewable biogas.

12.6 Hydropower

12.6.1 Overview

Before the 1920s, Vermont relied on hydro resources almost exclusively to meet its electricity needs.[413] Many projects were small, and served a modest local demand. Even though the state is now less reliant on small hydro sources, in-state hydroelectric power still makes a significant contribution to Vermont's electric load, while out-of-state hydro is a major component of our supply.

Hydropower has many benefits. It is renewable, has low emissions of GHGs, and contributes to the stability of the electric grid. Vermont-based hydropower also can support the local economy through jobs and taxation. For all these reasons, Vermont should preserve its use of the local hydropower resources and support environmentally sound in-state hydropower development.

12.6.2 State of the Market

Vermont today has 71 FERC-licensed hydropower generation facilities, with a total estimated installed capacity of more than 750 MW. Subtracting the Connecticut and Deerfield River facilities — which serve customers outside the state — and adding in unlicensed facilities, the installed in-state capacity is closer to 200 MW. The generation from these facilities powers nearly 10% of Vermont's electric load.

Exhibit 12-35. Vermont Hydroelectric Projects

Plant Owner	Capacity (MW)
GMP[414]	99
Independent Power Producers[415]	41
Standard Offer[416]	2
Municipal Utilities[417]	30
All Other	28
Total	*200*

413 U.S. Dept. of the Interior, *Hydroelectric Generating Facilities in Vermont,* www.burlingtonvt.gov/sites/default/files/PZ/Historic/National-Register-PDFs/Hydroelectric%20Generating%20Facilities%20in%20VT.pdf

414 GMP, "The Supply of Electricity" (*Integrated Resource Plan*, Ch. 3), www.greenmountainpower.com/upload/photos/4773._2014_GMP_IRP_The_Supply_of_Electricity_Chapter_112514_Clean_and_Final.pdf

415 static1.1.sqspcdn.com/static/f/435218/25863851/1421442956143/Schedule+B+-+2014-2015-FY15.pdf?token=TvpupnR2Vg1aInvc0JUzhk%2FY2Ic%3D

416 vermontspeed.com/projects-online/

417 DPS data

A portion of current capacity was added in the 1980s under the Public Utility Regulatory Policies Act (PURPA) of 1978. Spurred by the energy crises of the 1970s, PURPA provided economic incentives for the development of small hydro projects. Under PURPA, 41 new hydro facilities were constructed in the state, though at a higher price relative to those available in the subsequent wholesale power market.

The pace of hydro development dropped off significantly after the early 1990s, due to a number of factors including the loss of economic incentives, stricter permitting requirements, and the elimination of "low-hanging fruit." Advocacy efforts by the hydropower community led to several studies to analyze the potential for new hydropower resources. Several projects that have recently or will soon come online provide insights into what might be required if we are to add more in-state hydropower to the mix — and to keep what we now have.

Current state policy continues to support the development of environmentally sound in-state hydroelectric projects. This policy achieves the objectives of helping Vermonters meet their long-term energy needs with low-costs renewable resources — hydro projects produce the least expensive power currently being generated by Vermont utilities — while also protecting the health of Vermont's waters.

12.6.3 In-State Resources

It is challenging to develop an accurate estimate of how much undeveloped hydro capacity Vermont has that can be developed in a cost-effective, environmentally benign way. Estimates range from 25 MW at 44 sites (ANR, 2008[418]) to 434 MW at 1,291 sites (U.S. DOE desktop study, 2006).[419] A 2007 study for the DPS identified more than 90 MW developable at 300 of the existing 1,200 dams.[420]

Under any assessment, it is clear that the best hydropower sites have already been developed. There are very few undeveloped sites that could support capacity greater than 1 MW, and a relatively low number in the 500 kW to 1 MW range. There are many potential smaller community and residential sites sized at less than 200 kW. But because the permitting requirements for hydropower do not necessarily scale with size, the economics are skewed in favor of larger sites, in the absence of incentives that would make the smaller sites capable of supporting up-front environmental and engineering studies, along with the extensive, lengthy permit process that hydropower has to undertake at the federal level.[421]

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418 Vt. ANR, *The Development of Small Hydroelectric Projects in Vermont* (Report to the Legislature, 2008), www.vtwaterquality.org/rivers/docs/rv_smallhydroreport.pdf

419 U.S. EERE, *An Assessment of Energy Potential at Non-Powered Dams in the United States* (2002), www1.eere.energy.gov/water/pdfs/npd_report.pdf

420 Lori Barg, *The Undeveloped Hydro Potential of Vermont* (Community Hydro, Plainfield, 2007), publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Resources/Hydro/DPS-Undeveloped-Hydro-Potential-FINAL-VERSION.pdf

421 U.S. FERC, *Small/Low Impact Hydropower Program,* www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact.asp

One generally cost-effective way to increase hydropower's contribution to Vermont's electricity mix without developing non-powered dams is to upgrade existing hydroelectric facilities, by installing small turbines at the dams that utilize conservation bypass flows, or by installing new turbines that can operate efficiently and over a wider range of flows. These upgrades are often possible without changing the current operating requirements — i.e., power production can be increased without additional environmental impacts. In some cases, these upgrades can even reduce environmental impacts. Green Mountain Power has taken advantage of relicensing of its dams to change operations in ways that meet modern water-quality standards while increasing output.[422] Increased hydropower output resulting from upgrades that are made after June 30, 2015 to plants smaller than 5 MW also likely qualifies as a distributed renewable generation resource under the Renewable Energy Standard.[423]

Municipal water supply and wastewater treatment pipelines can be retrofitted with turbines, to capture excess pressure in these systems without otherwise altering the system's regular operation. Such in-pipe hydroelectric systems have minimal environmental impact, although they also produce only a small amount of electricity. The town of Bennington has developed such a project,[424] as has the city of Barre,[425] following a 2013 change in federal permitting law that expedited the processing and review of conduit systems.[426]

12.6.4 Out-of-State Hydro Resources

Canadian Hydropower

Vermont currently receives about a third of its electricity from out-of-state hydro, principally from Hydro-Quebec (HQ). In 2010, the Legislature officially recognized this resource as renewable.[427,428] HQ power offers greater price stability than the market, is priced competitively with or favorably compared to the market, and does not contribute to our region's air quality problems. Further, since the power is

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422 GMP, "GMP Upgrades and Doubles Hydro Generation at Otter Creek Hydro Plant in Proctor" (press release, July 2015), news.greenmountainpower.com/manual-releases/GMP-Upgrades---Doubles-Hydro-Generation-at-Otter-C?feed=d51ec270-a483-4f6c-a55e-8e5fbe2238c2

423 legislature.vermont.gov/assets/Documents/2016/Docs/ACTS/ACT056/ACT056%20As%20Enacted.pdf

424 www.vtenergyatlas-info.com/wp-content/uploads/2010/02/Bennington-hydro-final-rpt.pdf

425 Fuss & O'Neill, *Barre Micro-Hydro Project* (presentation for Community Energy and Climate Change Conference), www.vecan.net/wp-content/uploads/jeff-McDonald_VECAN_Barre-Micro-Hydro-Project.pdf

426 U.S. FERC, *Hydropower Regulatory Efficiency Act of 2013*, www.ferc.gov/industries/hydropower/indus-act/efficiency-act.asp

427 Office of the Governor, "Governor Signs Final Bills of the 2009-2010 Biennium" (press release, June 2010) ,www.vermont.gov/portal/government/article.php?news=1829

428 All power purchased from HQ is system power and not tied to any single unit. Of the HQ power in 2010, 99% is from hydro. Hydro-Quebec, *Sustainability Report 2014*, www.hydroquebec.com/publications/en/corporate-documents/sustainability-report.html

supplied from many generators, its reliability is based on HQ's total system reliability, rather than the performance of a single dam or plant.[429]

The original 30-year, 310 MW contract between Vermont utilities and HQ is in a phase-out period. A new, 26-year, 225 MW contract took effect in late 2012. The electricity is priced at $58.07 per MWh to start, and will be adjusted annually with a formula designed to keep the contract aligned with the power markets but buffered from volatility and sustained high-price periods. Under this new contract, the contracting utilities also purchased an equivalent quantity of environmental attributes[430], corresponding to the energy from the HQ power-system mix of at least 90% hydroelectricity. The utilities are allowed to resell these attributes, provided that they split the proceeds with HQ. However, these environmental attributes are not currently valued in renewable energy markets outside of Vermont and are expected to be retired to meet Tier 1 of the Renewable Energy Standard.

Under the HQ contract, the initial amount of energy provided is equal to the current transfer capability at the Highgate interconnection, which is 218 MW. If Highgate's transfer capability is increased to 225 MW during the term of the contract, delivered energy will likewise increase. Although the contract amount is tied to the size of the Highgate interconnection, Vermont can and does receive power through other interconnections, and the HQ contract does not require delivery of power at Highgate.

HQ currently has 36,643 MW of generating capacity, capable of producing 173,000 GWh annually.[431] HQ has a surplus of approximately 30,000 GWh, resulting from decreased exports to the U.S. following the advent of abundant natural gas supplies in this country, as well as new projects (including a number of wind projects) coming online in Canada.[432] It is not surprising, then, that there are at least three active proposals for transmission lines that would bring HQ power to the New England region, especially given the renewable power needs of the southern New England states.[433]

Other Canadian hydro resources may become available to Vermont and the region in the future. Newfoundland and Labrador have started a new major hydro project, the Lower Churchill Development, that will be built in phases, with the first complete by 2017. When fully online, this facility should add another 3,000 MW to the electric grid; it is still undetermined whether that will be sold to New England or to other parts of Canada, such as Ontario. There are a number of proposals to import additional

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429 www.vermontelectric.coop/content/hydro_quebec_final_psb_order.pdf

430 Environmental attributes means the characteristics of a plant that enable the energy it produces to qualify as renewable energy and include any and all benefits of the plant to the environment such as avoided emissions or other impacts to air, water, or soil that may occur through the plant's displacement of a nonrenewable energy source.

431 Hydro-Quebec, *Power Generation, Purchases and Exports* (2014), www.hydroquebec.com/sustainable-development/energy-environment/power-generation-purchases-exports.html

432 Energy Council of Canada, *Economics: The Business of Energy* (2014), www.energy.ca/sites/energy.ca/files/energy_council_of_canada_-_economics.pdf

433 John Herrick, "Special Report: Vermont Smack in the Middle of Crucial Electricity Supply and Demand," vtdigger.org/2014/06/08/special-report-vermont-smack-middle-crucial-electricity-supply-demand/

Canadian hydropower into New England via merchant transmission (see Chapter 11 for more details). Merchant hydropower generation is also available in the provinces neighboring Quebec.

Domestic Hydropower

Since the late 1950s, Vermont has obtained hydropower from the New York Power Authority (NYPA) and its predecessor, the Power Authority of the State of New York (PASNY). This power is very inexpensive, thanks to historical federal subsidies for hydro dam construction. Until July 1985, Vermont received 150 MW of 0.2 cents per kWh energy from the St. Lawrence and Niagara hydro projects. As fuel prices soared in the 1970s, other states purchased low-cost NYPA power, reducing Vermont's share. Vermont's current NYPA entitlement — which all goes to our municipal utilities — is 15 MW, which is guaranteed until 2025. Even at the reduced level, the price continues to make this energy attractive to the Vermont municipal utilities that receive it.

Stowe Electric Department has been purchasing power from the Worumbo hydroelectric project in Lisbon Falls and Durham, Maine, since 2010. The current contract, for 2.613% of the output of the production of this 19 MW facility, is set to terminate on May 31, 2016.

Some Vermonters feel that in 2003, Vermont lost an opportunity to gain ownership of and access to the eight hydroelectric dams on the Connecticut and Deerfield Rivers, with their nearly 500 MW of renewable power, when the prior owner suffered financial distress and sold the dams. The final cost of the purchase to the new owner, TransCanada — $500 million — would have added significant increased risk to Vermont's finances and, given market electric prices between 2003 and 2011, would not have been offset by savings in retail sales. Since many Vermonters value this local renewable resource, which provides some tax revenue and jobs to the state, it would be a positive step for Vermont utilities to enter into contracts for power from the eight dams, assuming that acceptable price and quantity terms could be negotiated. The state will also watch for any new opportunity to purchase these hydro facilities if they become available.

Other hydropower resources in the northeastern U.S. may become available to Vermont utilities.

12.6.5 Siting and Permitting

Hydroelectric projects — unlike solar, wind, biomass, and other grid-connected renewable electricity projects — are required to obtain authorization from the Federal Electric Regulatory Commission. FERC authorization is necessary whether the project is large or small (the largest FERC-authorized project in Vermont is 320 MW, and the smallest is 5 kilowatts). The FERC process can be time- and resource-intensive, especially for projects that have greater potential for impacts on natural and cultural resources. New projects may also require a permit from the U.S. Army Corps of Engineers. These federal permits trigger state review, as delegated under the federal Clean Water Act and the National Historic Preservation Act.

FERC's permitting process is well-defined, but can take two to seven years to complete. This long timeline is largely due to the need to gather the information necessary for the regulatory agencies to make informed permitting decisions, and to provide for public participation in the process. Hydropower projects involve the use of public waters, a public trust resource, so there is considerable public interest in these developments. Care is also taken because the terms of the permits are at least 30 years. One class of permits — called *exemptions* — has no expiration date; those projects may operate indefinitely without further review, as long as they are in compliance with the terms of their permit.

Some European countries have regulatory regimes that seem to facilitate hydro development, though it is important to note that they are operating under a different suite of national laws that are difficult to compare with U.S. laws governing hydropower projects. Hydropower developers both in and outside of Vermont continue to be challenged by the length and expense of permitting, an issue that state legislatures and the U.S. Congress periodically attempt to address. Proposals to date have involved either lowering the standards of resource protection or the level of scrutiny the project receives from state and federal resource agencies and the public, and have largely received strong pushback from those entities and others.

In 2012, the Vermont Legislature passed Act 165, which directed the DPS commissioner, in consultation with the Secretary of ANR, to "seek to enter into a memorandum of understanding [MOU] with the Federal Energy Regulatory Commission (FERC) for a program to expedite the procedures for FERC's granting approval for projects in Vermont that constitute small conduit hydroelectric facilities and small hydroelectric power projects."

After consulting with FERC and many stakeholders, the agencies concluded that it was infeasible to enter into such an MOU, and that the next best way to expedite the development of small hydropower projects in Vermont was to provide greater assistance to developers early on in a project; to better coordinate communications to developers and to FERC; and to identify projects that could gain support from the state resource agencies, then communicate such support to FERC to expedite the permitting process. An interagency MOU, which was fully executed by the DPS, ANR, and the Agency of Commerce & Community Development in July 2013, provides for such enhanced coordination, including identification of and assistance to developers of low-impact projects of high public value (such as those owned by public entities and those utilizing existing infrastructure), as resources allow.

To identify and assist low-impact projects, the agencies developed a two-step screening process: the Vermont Small Hydropower Assistance Program, which debuted in the summer of 2015. The first step involves a desktop review of project proposal characteristics; if that screening is successful, the second step is project proposal review based on a site visit, as appropriate. The agencies will provide enhanced assistance to projects that screen as low impact (for instance, waiving scoping periods in the FERC process and/or representing to FERC that agency concerns have been satisfied).[434]

[434] publicservice.vermont.gov/topics/renewable_energy/resources#hydro

12.6.6 Benefits

Hydroelectricity is produced from our rivers, and operates without generating carbon emissions or pollutants. Other than low-flow periods in the summer, the hydropower resource is generally consistent and abundant — and the infrastructure is long-lived, leading to low-cost, steady power that can be used to help integrate the more intermittent renewable resources, such as wind and solar, depending on the operating restrictions of the individual hydroelectric plants. Many of Vermont's utilities own hydroelectric resources, which make up a significant, low-cost portion of their electric power portfolios. Some of Vermont's municipal utilities were formed in main part due to the development of local hydropower resources, which continue to play a major role in keeping rates competitive for their customers.

Hydroelectric resources also employ local engineers and operational staff, and have led to local entrepreneurial efforts to develop new, low-impact technologies.[435] According to the Vermont Clean Energy Industry Report, hydropower employs 229 people in the state.[436] Vermont-based hydropower resources also pay property taxes, provide recreational opportunities such as boating and fishing, and are important aesthetic and historic resources to a number of towns.

12.6.7 Challenges

Despite the many benefits that hydropower provides, the hydro resource is already heavily developed in Vermont and elsewhere, and the resulting impacts on the state's and the region's waterways have not been inconsequential. These environmental impacts include intermittent manipulation of flows and water levels, a possible increase in flood hazards resulting from the disruption of natural river processes, loss and degradation of riverine aquatic habitat, greenhouse gas emissions from reservoirs, and barriers to the movement of fish and other aquatic life. For these reasons, construction of new dams is unlikely to be permissible in Vermont under the anti-degradation policy in the Vermont Water Quality Standards, and is not supported by ANR.

Existing dams retrofitted for hydropower, as well as those undergoing relicensing, are also required to meet Water Quality Standards, which were adopted and have evolved in the time since many Vermont dams were first licensed. Projects going through relicensing will likely need to change operations in order to provide adequate flows in the bypass reach, and to operate closer to run-of-river mode. They may possibility need to incorporate fish passage, which can be a considerable expense. In relicensing, projects that had previously stored water in impoundments, for use during peak demand, may no longer be able

[435] www.littlegreenhydro.com/

[436] BW Research, *Vermont Clean Energy 2015 Industry Report,* publicservice.vermont.gov/sites/psd/files/Announcements/VCEIR%202015%20Final.pdf

to do so to the same extent; and projects that had used flows to the detriment of aquatic life may need to sacrifice some production. To some extent, the resulting losses in peak power and production potential can be mitigated by the implementation of modern controls and more efficient equipment. But even so, this issue needs to be considered by hydro plant operators, especially utilities, as they plan for their future electricity portfolios.

It is also important for hydroelectric facility owners and operators to be aware of the importance of proper facility maintenance and the financial implications of maintenance costs, and to plan ahead for these expenses. Improper maintenance and operation of these facilities is a liability not just for the balance sheet but also for the environment, especially if it results in dry spawning habitat or dewatered wetlands.

The environmental impact of a project is not necessarily related to its size, so smaller hydroelectric projects (often called micro-hydro, mini-hydro, or community hydro) are not necessarily low-impact. The Vermont Small Hydropower Assistance Program contains the following screening criteria; a project that meets them is likely to meet a low-impact standard:

- Will not be located on Class A waters, Outstanding Resource Waters, or federally or state-protected river reaches.[437]
- Will be located at an existing dam, or project will not require a dam or other impoundment.
- Will be located on lands controlled by applicant or otherwise demonstrate support from adjoining landowners.
- Will not increase the impoundment elevation.
- Will be operated as true run of river.[438]
- Has proposed bypass flows that will meet hydrologic standards as defined by the ANR Flow Procedure:[439]

Season	Period	Median Flow Standard[440]	Default (cfs/mi^2)
Fall/winter	Oct 1 — Mar 31	February	1.0
Spring	Apr 1 — May 31	April/May	4.0
Summer	June 1 — Sep 30	August	0.5

437 Lists of Class A and Outstanding Resource Waters are available on ANR's Natural Resources Atlas: anrmaps.vermont.gov/websites/anra/. Federally protected waters can be identified via www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact/get-started/sites.asp

438 A true *run-of-river project* is one that does not operate out of storage and, therefore, does not artificially regulate streamflows below the project's tailrace. Outflow from the project is equal to inflow to the project's impoundment on an instantaneous basis.

439 For more detail: www.anr.state.vt.us/dec/waterq/rivers/docs/rv_flowprocedure.pdf

and www.fws.gov/newengland/pdfs/Flowpolicy.pdf

440 Application of the fall/winter and spring period flows for spawning and incubation will be determined site-specifically by the Dept. of Fish & Wildlife. If not required, the August median flow will be applied year-round.

OR

Where there is virtually no bypass (tailrace discharges at the dam or into plunge pool close to the dam such that adequate circulation is maintained) and will have a spillage proposal of at least 7Q10 drought flow.[441]

Because of the stringent and lengthy permitting process hydropower is required to undertake, at least in comparison with other renewable sources of electricity, incentives continue to play an important role for the development of desired resources in Vermont. Net metering at the retail rate has proven sufficient for some projects, including some whose PURPA contracts are expiring. Those projects are likely to have paid off their debts and may have FERC exemptions, meaning their licenses do not expire and they are not subject to definite review under modern Water Quality Standards.[442]

It is clear that new hydroelectric projects — especially those above the net metering threshold of 500 kW — and perhaps capacity upgrades at existing facilities will need incentives to develop in any meaningful numbers. The Standard Offer program, which awarded above-market contracts to two of the four hydro projects that have been developed since the last CEP, may be an appropriate venue in which to further explore incentives for low-impact hydro development in the state.

Strategies and Recommendations

Strategy 1: Maintain production levels from existing Vermont-based hydro projects to the extent they comply with Water Quality Standards

Recommendations

(1) *Identify opportunities to increase production at existing facilities through implementation of advanced operational controls, more efficient equipment, and/or conservation flow turbines at the dam.*

(2) *Develop incentives through the Standard Offer and/or Clean Energy Development Fund to increase production from existing facilities.*

(3) *Implement a multi-agency hydropower project tour to review operations and provide recommendations for operational controls and equipment upgrades necessary to meet Water Quality Standards well in advance of relicensing.*

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441 The 7Q10 refers to the lowest average streamflow expected to occur for seven consecutive days with an average frequency of once in 10 years. If it's a gauged stream, ANR can supply this statistic. If not, use 0.1 csm, the statewide value.

442 ANR does have regulatory tools to bring unlicensed facilities that violate Water Quality Standards into compliance over time.

Strategy 2: Develop new Vermont-based hydro projects to the extent they comply with Water Quality Standards

(1) Commission a study of the economically developable hydro opportunities in Vermont, as an update and refinement of previous studies. Use this as a basis for Standard Offer, Clean Energy Development Fund, and other incentive development, and possibly for coordinated interagency support.

(2) Provide financial support to projects that meet the Vermont Small Hydropower Assistance Program low-impact criteria in order to conduct engineering and environmental studies necessary to proceed through permitting.

(3) Work with ANR and other stakeholders to assess watershed-wide opportunities to increase hydropower (at existing dams or operations) while also decreasing the overall environmental impact of dams (through targeted removals of existing dams that have been determined as inappropriate for hydropower, after a review of their hydroelectric potential and environmental circumstances).[443]

Strategy 3: Secure additional stable long-term hydropower supply potentially available from Canadian provinces and other states in the Northeast.

(1) Assess the optimal amount of out-of-state hydropower desirable in a Vermont energy portfolio and evaluate opportunities to secure favorably priced, long-term contracts for that power.

(2) Evaluate opportunities to benefit from planned transmission projects that will bring hydropower to or through Vermont from out-of-state.

[443] Because dams serve multiple purposes, the Legislature has required that dams meeting certain criteria cannot be removed unless their hydroelectric potential is determined.

13 Non-Renewables

The non-renewable resources that this chapter examines include:

- Petroleum,
- Natural gas,
- Coal, and
- Nuclear.

Each of these sources can be used to generate electricity; petroleum and natural gas are also used to power vehicles and provide heat in buildings and industry. This chapter addresses issues and opportunities, and makes recommendations related to energy use from these resources and technologies.

Most of the energy used in Vermont comes from non-renewable sources. Natural gas and petroleum products account for 62% of Vermont's total energy usage — and 100% of Vermont's energy-related in-state greenhouse gas (GHG) emissions.[444] Vermont consumed 15.3 million barrels of petroleum and 9.6 billion cubic feet of natural gas in 2013, the most recent year for which data are available.[445]

Although they are the state's biggest drivers of climate change and air pollution, fossil fuels continue to account for our majority share of energy consumption because of their relatively low price, well-established distribution system, compatibility with existing infrastructure and equipment, and on-demand characteristics.

Whereas electricity and natural gas are regulated monopoly industries with rate-setting, infrastructure-siting, and planning overseen by the PSB, petroleum products and coal are distributed without state rate and infrastructure regulations. Extraction and distribution of these fuels are regulated nationally by environmental and safety standards, but the state holds little regulatory authority over their prices or distribution. As a result, fewer policy and regulatory levers are available in this sector to influence the market.

As the state seeks to drive energy consumption away from these polluting fuels, the most effective tools lie in encouraging efficiency and clean and affordable alternatives for space heating, transportation, and electricity. The recommendations in those chapters are designed to reduce fossil fuel consumption. For applications where electrification, biomass, or other renewable fuels are unavailable, the negative impacts

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444 U.S. EIA, *Energy-Related Carbon Dioxide Emissions at the State Level, 2000-2013,* Table 2, www.eia.gov/environment/emissions/state/analysis/

445 U.S. EIA, *Vermont State Profile and Energy Estimates*, www.eia.gov/state/data.cfm?sid=VT

of fossil fuel use can be somewhat mitigated by choosing cleaner fuels such as natural gas and reduced-sulfur heating oil, and by encouraging the most efficient, clean-burning technologies available. Blending renewable biodiesel and biogas into existing fossil fuel delivery systems will reduce the environmental and health impacts of using those fuels.

13.1 Petroleum

13.1.1 Overview

Petroleum products provide 49.6% of Vermont's energy and account for 92% of the state's GHG emissions from energy use.[446] Petroleum is processed into a wide array of energy products, including jet fuel and residual fuel oil, but the bulk of Vermont's use centers on just three products: gasoline, distillate fuel oil (which is used as both diesel gasoline and home heating oil), and propane. Transportation, space heating, and water heating are the state's primary drivers of petroleum consumption.

Gasoline is the largest single contributor to both energy and GHG emissions in the state, accounting for 28.9% of total energy use. The transportation sector accounted for 44.6% of the GHG emissions in Vermont in 2012, with the vast majority of those emissions coming from gasoline and diesel. Up to 10% ethanol is blended into gasoline, so there is a small "renewable" component to gasoline consumption. For a more detailed discussion of ethanol, see the Biofuels section of Chapter 12.

Distillate fuel oil, which is both No. 2 home heating oil and diesel fuel, makes up 18.3% of Vermont's energy usage and is used in medium and heavy-duty transportation and for space and water heating. Approximately 68 million gallons of heating oil are sold annually for residential consumption in Vermont, and about 71 million gallons are used as diesel fuel in transportation. Propane, also referred to as liquefied petroleum gas (LPG), is used in space heating, water heating, and cooking and is expected to continue its strong growth. Approximately 67 million gallons of propane are sold in Vermont each year for residential consumption.

Commercial enterprises sometimes use heating oil and propane for space heating, but also use them for air conditioning, refrigeration, cooking, and a wide variety of other equipment. Total annual commercial consumption in Vermont is 24 million gallons of heating oil and 43 million gallons of propane.

Industrial enterprises typically use heating oil and propane for manufacturing — or on the farm, in the forest, on the construction site, etc. — and much less for space heating. Industrial consumption in Vermont consists of 21 million gallons of heating oil and four million gallons of propane.[447]

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[446] U.S. EIA, *Energy-Related Carbon Dioxide Emissions at the State Level, 2000-2013,* Table 2, www.eia.gov/environment/emissions/state/analysis/

[447] All petroleum-consumption data in this section comes from the Energy Information Administration's State Energy Data System (SEDS) consumption data. The data are current as of 2013, the most recent available dataset. U.S. EIA, *About SEDS,* www.eia.gov/state/seds/

Kerosene, used primarily for space heating where fuel tanks are outside, but also in stand-alone space heaters and to blend with off-road fuel to prevent gelling in cold weather, makes up a small portion of Vermont's residential energy consumption.

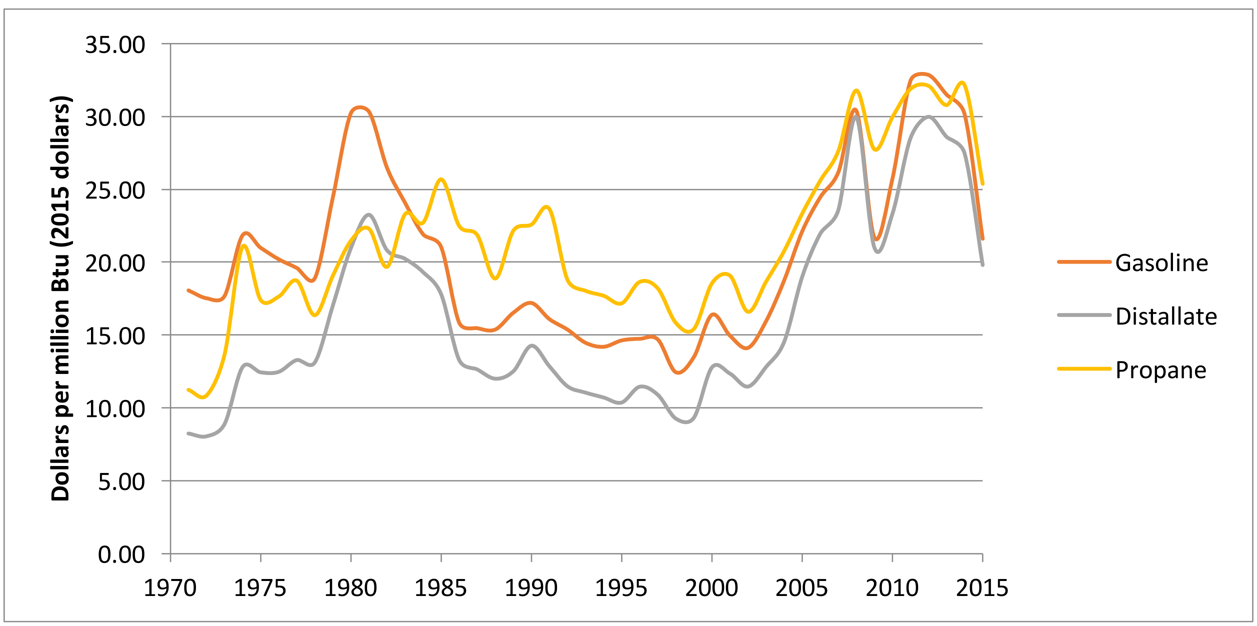
13.1.2 State of the Market

Prices

Since 2014, prices for gasoline, fuel oil, and propane have declined steeply. Domestic petroleum production has grown rapidly in the U.S. since 2009; production has also accelerated in Russia, Nigeria, Iraq, and Saudi Arabia, giving a lift to global supplies. Meanwhile, demand in Europe has dropped slightly and growth in demand in Asia is moderating, due to an economic slowdown and increasing vehicle efficiency. This confluence of market forces has led to the recent decline in prices.

Global market forces shaping oil prices are unpredictable — but long-term the trend in petroleum prices is upward, with a high degree of volatility. Because nearly half of all our households rely on home heating oil and propane, and nearly all rely on gasoline or diesel for transportation, price uncertainty and price spikes have a significant effect on Vermonters, just as they do on commercial and industrial enterprises.

Exhibit 13-1. Prices for Petroleum Products in Vermont, 1970-2015 (2015 Dollars)



Source: EIA[448]

[448] U.S. EIA, *Motor Gasoline, Distillate Fuel Oil, and Liquefied Propane Gas Price data for Vermont*, www.eia.gov/state/seds/

The recent downward trend in prices has led to a slight uptick in consumption, although total consumption has not yet rebounded to pre-recession levels. Efficient vehicles and a drop in vehicle miles traveled are likely holding down demand in response to lower prices — although if prices continue to stay low, there may be increased demand.

Prolonged depressed prices for petroleum products make efficiency investments and renewable, low-carbon alternatives less competitive. Low prices may motivate investment in petroleum-reliant infrastructure like new boilers or less efficient vehicles, and consumers may be less likely to invest in electric vehicles, weatherization, or wood heating infrastructure. These effects have not been observed yet, but may occur if prices remain low for a prolonged period.

The lower price of oil has made petroleum products more attractive in the regional electricity market. As a result, during winter price peaking of natural gas, some electric generators have been switching to oil, which is more polluting.[449]

Industry Consolidation

Recent years have seen consolidation among retail dealers of heating oil and propane. Demand for home heating oil has been steadily dropping, and as fewer gallons are sold, fewer dealers can economically compete. Traditionally, most heating fuel dealers have been small second- or third-generation family-owned businesses[450] — and although there are still many small businesses, consolidation has resulted in an overall decline in the number of retail sales operations.

Because petroleum products are unregulated at the state level (meaning prices and supply are driven by market forces rather than being set by the state), a functioning competitive market is crucial for fair and efficient pricing. As consolidation continues, it is important to monitor market power to ensure competitive pricing. Maintaining market competitiveness is also important in the retail gasoline market.

13.1.1 Resources

All petroleum products consumed in Vermont are imported; the state has no known petroleum reserves. In 2013, the state spent nearly $2.3 billion annually — about 8% of Vermont's GDP — on petroleum products that are extracted and refined elsewhere. Some small percentage of those expenditures remains in the state, with retailers that are often small-business franchise owners, but overall this is a significant flow of financial resources away from the state's economy.

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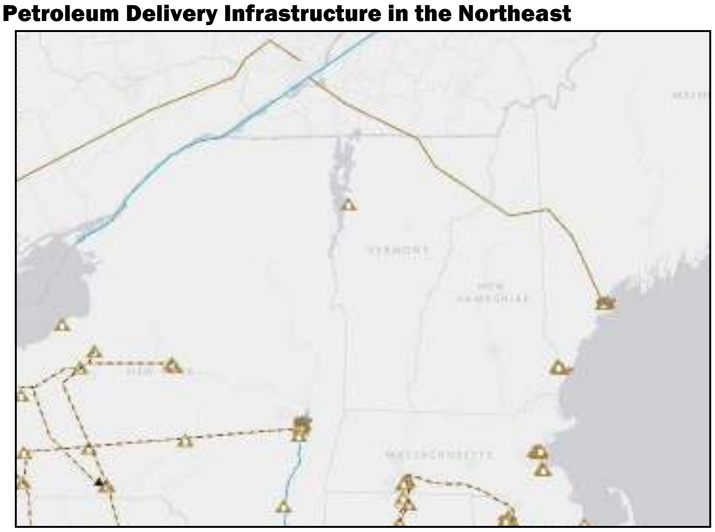
[449] ISO New England, *2015 Regional Electricity Outlook*, www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf

[450] Matt Cota, *2011 VFDA Heating Fuel Fact Sheet* (Vermont Fuel Dealers Association)

Petroleum products are imported to Vermont via a variety of mechanisms, although we are relatively isolated from major supply lines and pipelines. Albany, N.Y., Montreal, Quebec, Portsmouth, N.H., and Portland, Me. are all major hubs for petroleum products in the Northeastern region, providing heating oil, gasoline, and other refined products to Vermont via rail and tanker truck. Most of the products consumed here are refined at major East Coast refineries in New York and New Jersey, or at refineries in St. John, New Brunswick, Canada. Some refined products, imported via rail from Albany and Montreal, are stored and distributed from facilities on the Burlington waterfront.

Major supply disruptions can occur if rail or truck traffic is interrupted between those "hub" cities and Vermont, or if East Coast refineries go offline. Because a majority of Vermont homes and businesses rely on petroleum products for heating, transportation, and production, disruption of supply can cause serious effects, especially during winter.

Exhibit 13-2. Petroleum Delivery Infrastructure in the Northeast



Source: EIA[451]

Heating oil supply disruptions are slightly buffered by the Northeast Home Heating Oil Reserve, through which the federal government stores heating oil in Groton, Ct. and Revere, Mass. and sells it to private suppliers in the event of major supply disruptions or price spikes. The federal government also maintains the Northeast Gasoline Reserve, established in response to disruptions occurring during Hurricane Sandy in 2013. The gasoline reserve holds one million gallons in three locations.

The heating oil and gasoline storage locations are further away from Vermont than Albany and Montreal, where current supplies are usually procured. In the event that these reserve supplies are needed, prices would likely rise in the state, and fuel dealers would be forced to travel further to obtain supplies. There are no nationally maintained propane reserves in the northeast.

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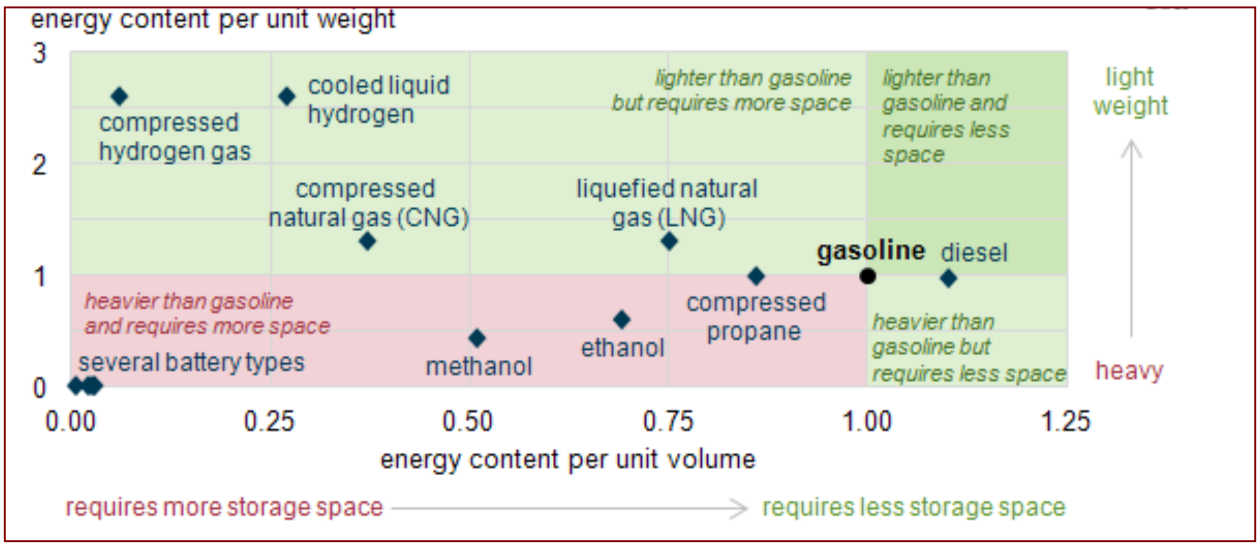
[451] U.S. EIA, *U.S. Energy Mapping System*, www.eia.gov/state/maps.cfm

13.1.2 Benefits

Petroleum products offer many benefits that make them an attractive option for transportation, heating, and industrial processes. They are energy-dense, easy to transport, supported by existing infrastructure, and they require very little labor from the end user.

Petroleum products are the among the most energy-dense fuel sources available: they have a high energy content per unit of weight or volume. This is especially attractive for transportation applications, because vehicles must accommodate storage capacity for their own fuel. Electric batteries are heavy, and natural gas, even in a compressed or liquid form, takes up more space per unit of energy than gasoline or diesel. Gasoline and diesel remain the most energy-dense options by volume for transportation.

Exhibit 13-3. Energy Density of Transportation Fuels Indexed to Gasoline (Gasoline = 1)



Source: EIA[452]

Petroleum products are liquid, which means they can be easily transported via tanker truck, tanker ship, pipeline, and rail car. Unlike many renewable energy options, petroleum products can be stored and burned on demand to produce energy.[453]

In 2014, low-sulfur heating oil rules went into effect in Vermont. The rules reduced the amount of sulfur to under 500 ppm in 2014, and will reduce sulfur to under 15 ppm by 2018. Removing sulfur from heating oil will improve the efficiency of existing equipment and allow for installation of high-efficiency condensing oil heat boilers. The removal of sulfur reduces SO_2 emissions as well as PM10 and PM2.5.

452 U.S. EIA, *Few Transportation Fuels Surpass the Energy Density of Gasoline and Diesel* (2013), www.eia.gov/todayinenergy/detail.cfm?id=9991

453 Wood, biodiesel, ethanol, some hydro facilities, and battery storage are renewable options that also can function on demand, although for other reasons those sources are not practical for all applications.

These emissions contribute to respiratory illness in the state, so ultra-low sulfur heating oil will reduce the negative health impacts of petroleum.

Existing infrastructure supports the use of petroleum. Refined petroleum products have been widely available since the early 1900s, and by the 1950s oil had surpassed coal as the most important energy source in the U.S. For decades, infrastructure investment has been driven by low prices for petroleum products. From funding highways over railways to zoning low-density suburbs, public policy at the local, state, and national levels has assumed ongoing, affordable access to petroleum products.

As a result, billions of dollars have been invested in public infrastructure and privately owned equipment that supports or relies on petroleum. For example, in Vermont about half of residences heat with oil, which means they have a significant investment in an oil furnace.[454] Because many of these homes likely do not own an adequately sized wood stove, they are unlikely to switch to wood even if wood is more affordable. About 72% of Vermont homes have either a wood stove or a fireplace as a backup source of heat. The same is true in transportation, because many homes and businesses already own gasoline-powered vehicles. Petroleum can be easily used throughout this system without any adaptation or additional capital costs.

13.1.3 Challenges

Even with its many advantages, petroleum presents a litany of challenges for the state. GHG emissions and other air pollutants from petroleum are high when compared with natural gas and renewables. The supply of petroleum is vulnerable to disruption from natural disasters and unexpected events along key supply lines. The price of petroleum is extremely volatile in the short term, and upward-trending in the long term. Any policies the state adopts to address these concerns will have wide-ranging ramifications for every sector.

Petroleum fuels are among the most heavily polluting fuels in Vermont's portfolio. Petroleum products used for transportation and in other equipment, such as construction and garden equipment, are Vermont's largest source of these pollutants: GHG emissions, air toxins, volatile organic compounds, nitrogen oxides, fine particulate matter (PM), carbon monoxide, and carcinogenic compounds such as benzene, aldehydes, and butadiene. These pollutants are known to cause cancer, aggravate respiratory diseases such as bronchitis and asthma, and increase the risk of pulmonary diseases for young children, developing fetuses, and older adults.[455] Except for coal, gasoline and distillate emit the most carbon dioxide per unit of energy emitted of any fossil fuel (around 160 lbs. per million Btu). Propane performs

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[454] NMR Group, et al, *Vermont Single-Family Existing Homes Onsite Report* (for Vt. DPS, Feb. 2013), publicservice.vermont.gov/sites/psd/files/Topics/Energy_Efficiency/EVT_Performance_Eval/VT%20SF%20Existing%20Homes%20Onsite%20Report%20-%20final%20021513.pdf

[455] Air Quality and Climate Division, Vt. DEC, *Mobile Sources Section,* www.anr.state.vt.us/air/MobileSources/index.htm

only slightly better at (139 lbs. per million Btu). Efficient equipment, blending biofuel, and emission control devices can reduce these emissions.

The supply of petroleum products in the state is vulnerable to disruption, which can increase price and make fuel inaccessible to many. Inclement weather, disruptions to international and domestic production or refining, or supply line disruptions can cause supply in the state to drop. Global economic forces affect the price and availability of fuel. Smaller-scale events, such as a downed train line into Albany, a major supply hub for Vermont, could affect the supply of gasoline, propane, and heating oil. Because petroleum constitutes such a large portion of Vermont's energy use, understanding and responding to disruptions in supply is critical to ensure energy security for Vermonters.

Prices for petroleum products are set by market forces. Prices have been trending upward since 2000, with an interruption in that trend during the Great Recession and again during the recent price drop due to changing supply-and-demand conditions. Since 2005, when natural gas and petroleum prices were decoupled by advances in extraction technology for gas, prices for petroleum products have consistently been higher than prices for natural gas. Where the natural gas supply infrastructure exists, these price differences have led to a regional shift to natural gas for some energy applications, namely electricity generation and home heating. For decades, wood has provided an economic alternative for homeowners, with greater incentive when petroleum prices spike. The unpredictability of oil prices makes planning difficult for businesses and residents in the state, and can affect fuel access for some economically vulnerable residents when prices do spike.

As discussed earlier, historical decisions about infrastructure have been supported by relatively inexpensive prices for petroleum products. Capital investments in petroleum-dependent equipment and infrastructure represent a significant sunk cost in Vermont. These investments "lock in" users to a specific fuel source. As systems reach the end of their useful life, it is important to consider replacing them with systems that can use renewable fuel types, such as electricity, wood, or higher blends of biofuels. In the meantime, adding renewable fuels, such as biodiesel, to petroleum supplies can reduce the negative impacts of transportation and heating on the environment.

Strategies and Recommendations

Moving to Renewable Alternatives

In many applications where efficiency and renewable alternatives can replace petroleum, the state is implementing policies to move away from petroleum use. Because petroleum is sold in unregulated markets, there is little the state can do directly in the petroleum markets to encourage efficiency and alternatives. Strategies for moving away from petroleum, including weatherization, transportation alternatives, electrification, and others can be found throughout this plan.

Because the primary applications of petroleum in the state are home heating, water heating, and transportation, it is critical to create viable alternatives in those areas. For detailed recommendations about space heating, see Chapter 7. Developing alternatives in transportation remains one of the most challenging areas for reducing petroleum use. Encouraging development of a market for liquid biofuels that can directly replace petroleum is one important strategy. For specific recommendations, see the Liquid Biofuels section of chapter 13. For details and recommendations about transportation more generally, see Chapter 8.

Maintaining Emergency Preparedness

New England states and fuel dealers participate in regularly scheduled conference calls to discuss any issues related to petroleum supplies. If a situation were to occur that could lead to or that did result in a fuel supply disruption, these same conference calls would be used to discuss the status of the fuel supplies, and strategies to restore supplies.

The statewide Energy Assurance Plan, originally drafted in 2013, will be updated in the spring of 2016. The purpose is to plan for emergency disruptions in energy supply across all resources, including liquid petroleum fuels. The plan includes an energy supply disruption tracking process, which is used to collect data on supply disruption events in an effort to learn from these events and minimize the disruption of future events. The DPS is the lead agency for State Support Function 12 (Energy), which includes thermal energy, energy for transportation, and energy to power communications. SSF12 is responsible for providing information to Vermont Emergency Management on the status of fuel supplies during an emergency.

1) *All state agencies should take into account market dynamics and petroleum prices when designing programs to support low-carbon heating and transportation alternatives, especially during times of low petroleum prices when alternatives are less competitive.*

2) *DPS, in conjunction with Vermont Emergency Management, should continue long-term energy assurance planning to monitor liquid fuel supplies and respond to emergency shortages.*

13.2 Natural Gas

13.2.1 Overview

Natural gas is an odorless, colorless gas that consists mostly of methane with a small amount of other volatile hydrocarbons. Most natural gas contains added mercaptan, to give it a characteristic smell that allows for the easy detection of leaks. Natural gas accounts for 7% of Vermont's total energy use.

Unlike in other parts of the country, the use of natural gas is limited by distribution to the northwestern corner of the state, and the population is highly dispersed. In the New England region, which has a shared electric grid, natural gas is a major fuel source. Vermont relies on natural gas at the regional level to provide electric power, especially when renewable intermittent sources are not generating. It is also used extensively and increasingly for heating and industrial processing.

Major applications for natural gas in Vermont include residential and commercial space heating, water heating and cooking, and industrial processes. Efficient new technologies, such as natural gas-powered cooling systems and heat pumps, are beginning to compete with electricity in other end uses. Compressed natural gas is being introduced as a fuel for commercial and industrial facilities, and there has been a small increase in its use for transportation, especially for fleet vehicles.

Natural gas produces lower emissions than other fossil fuels, and it is currently less expensive. When properly extracted and distributed, it is also cleaner than other fossil fuels. However, exposure to supply disruptions, price volatility, the region's heavy dependence on natural gas for electric generation, and GHG emissions associated with the fuel are all reasons for caution.

Adding biogas to the natural gas distribution system makes natural gas a more attractive option. Biogas is renewable methane produced by decomposing organic matter, such as cow manure on farms or suitable material in landfills. The methane is then captured and burned to generate electricity or for other applications.

13.2.2 State of the Market

In 2014, Vermonters consumed 10,554 million cubic feet (MMcf) of natural gas, accounting for about 7% of the state's total delivered energy use. The residential sector consumed about 36% of the state's natural gas, the industrial sector 14%, and the commercial sector 50%. The electric power and transportation sectors accounted for less than 1% of use. The residential sector uses natural gas primarily for space and water heating. An estimated one in six households uses natural gas as its primary fuel for space heating.[456]

The commercial sector is the fastest-growing area for natural gas use, because compressed natural gas can be trucked to areas where pipeline infrastructure is lacking. Overall usage in the state is going up as

[456] U.S. EIA, *Vermont Profile Analysis*, www.eia.gov/state/analysis.cfm?sid=VT

compressed natural gas becomes available for commercial and industrial applications and pipeline infrastructure expands.

Vermont Gas Systems, serving over 40,000 customers, is the state's only regulated natural gas distribution utility. Natural gas delivered via pipeline is currently available only in portions of Franklin and Chittenden counties. An expansion of the pipeline system is underway to provide gas to more densely populated portions of Addison County.

Vermont Gas Systems obtains its natural gas from Canadian supplies in Alberta and Ontario, which are transported to Vermont via a TransCanada pipeline. Vermont Gas Systems also maintains a supply of liquefied petroleum gas (propane). This is mixed with natural gas during the peak periods when demand is greater than the pipeline can supply. This allows VGS to supply its customers without costly firm contracts.

Another natural gas company, NG Advantage, serves customers in Vermont and neighboring states by compressing natural gas at its station in Milton (or at stations in other states), then delivering it via tanker truck to large commercial and industrial users. The use of compressed natural gas is increasing because natural gas is competitively priced and compressed natural gas can be delivered to customers who do not have access to pipeline infrastructure. Omya, Inc. uses liquefied natural gas trucked from Massachusetts.

Although the PSB has authority to regulate compressed natural gas companies under 30 V.S.A. § 203(1), it has exercised its discretion not to require them to obtain a Certificate of Public Good pursuant to 30 V.S.A. § 231, instead relying on competitive market forces to control rates, service quality, and reliability.[457] The supply of compressed natural gas is not guaranteed by state reliability requirements.

Overall increases in natural gas consumption in the state since 2011 are being driven by a rise in consumption of compressed natural gas in industry and transportation, an expansion of the distribution system by VGS, and colder winter weather.

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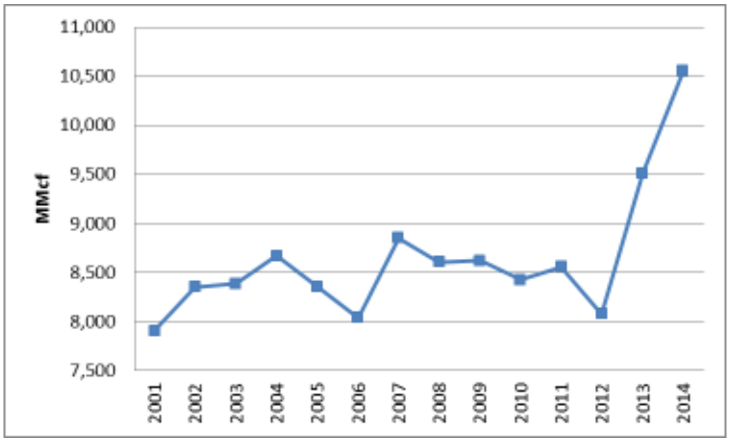
[457] PSB Docket Number 7866, Declaratory Ruling Re: Regulatory Status of NG Advantage LLC, October 2012, psb.vermont.gov/sites/psb/files/orders/2012/2012-10/7866%20Final.pdf

Exhibit 13-4. Natural Gas Delivered to Consumers in Vermont 2001-2014 (MMcf)



Source: EIA[458]

Shale gas discovery and extraction has driven recent natural gas prices lower. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. Dramatic increases in the quantity of technically recoverable shale gas resources, coupled with decreases in the expected costs of finding, developing, and producing gas from those resources, is leading to lower projections of costs for natural gas and gas-fired electric energy.[459]

Vermont Gas obtains gas from Canadian supplies in Alberta and Ontario, so price volatility and supply constraints in the New England market do not affect wholesale prices paid by Vermont Gas or retail prices paid by its customers in Vermont. Residential consumers in Vermont are insulated from winter price spikes because, as a regulated utility, VGS maintains a supply of propane that can be added to the system in the event of supply disruptions — and some larger VGS customers have interruptible contracts, so capacity can be directed to residential customers when capacity is tight. Although market prices can be volatile, VGS engages in a comprehensive hedging program, which limits customers' exposure to short-term price volatility.

13.2.2 Resources

Vermont does not contain any known gas reserves. Vermont Gas Systems imports natural gas from the gas fields of Alberta and Ontario, Canada via a TransCanada pipeline at Highgate. From there the gas is distributed to over 40,000 customers via 650 miles of underground lines. The state is not connected to the regional New England pipeline system. Recently proposed expansions in the pipeline system in New

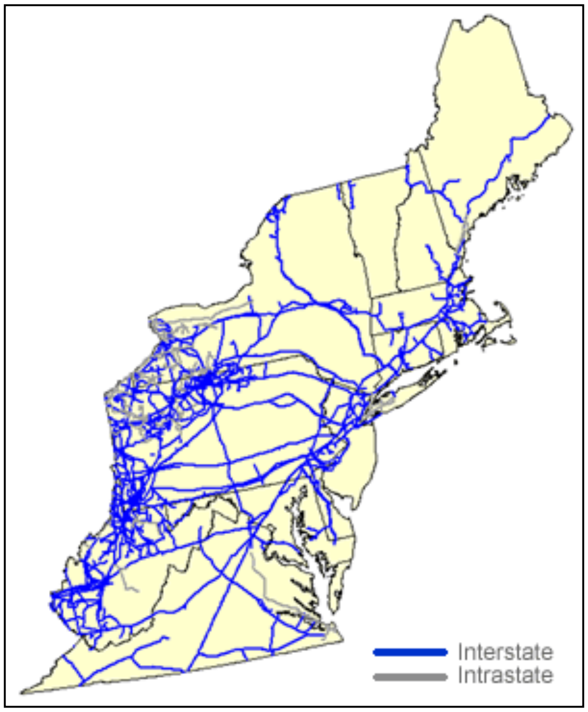
[458] U.S. EIA, *Natural Gas Consumption by End Use: Vermont*, www.eia.gov/dnav/ng/ng_cons_sum_dcu_svt_a.htm

[459] Rick Hornby, et al, *Avoided Energy Supply Costs in New England: 2015 Report* (for the Avoided-Energy-Supply-Component-Study Group, 2015), ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf

England, such as the proposed Northeast Energy Direct pipeline in Massachusetts, will not affect prices for wholesale gas here.

An expansion of Vermont's pipeline system to connect to the U.S. pipeline system would improve reliability in the event of pipeline disruptions in Canada, and by providing access to a wider market may provide more affordable gas.

Exhibit 13-5. The Northeast Natural Gas Pipeline System



Source: EIA

13.2.3 Natural Gas for Electricity Generation

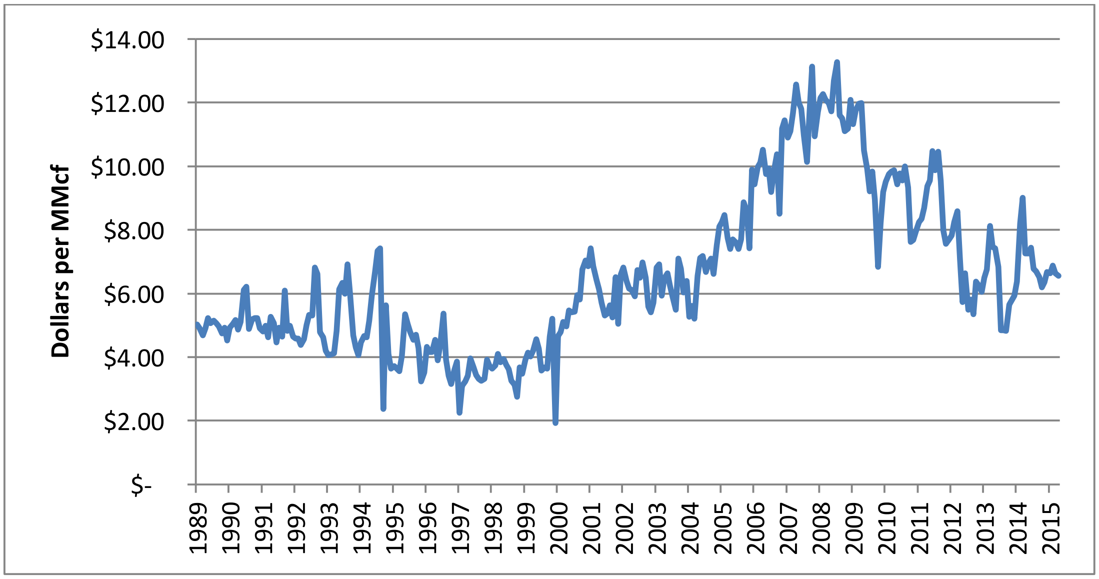
In Vermont, natural gas is a secondary fuel source for the wood-fired McNeil generator in Burlington; there are currently no electric facilities in Vermont that burn natural gas as a primary fuel. In any given year, 30-35% of electricity used in Vermont is purchased on the New England market. Due to Vermont's participation in the regional wholesale electricity market and the increasing importance of gas-fired generators in the system's resource mix, southern New England's natural gas supply is a crucial resource to ensure reliable electric service in Vermont.

Electricity generation in New England is highly reliant on natural gas, so wholesale market prices for electricity vary in close concert with natural gas prices. Price volatility in the natural gas market leads to price volatility in the wholesale electricity market. To the extent that Vermont electric utilities rely on market purchases, volatility in natural gas markets will affect utilities and ratepayers.

Vermont, along with other New England states, participated in an Avoided Energy Supply Costs study to develop reasonable cost estimates of energy consumption. The study forecast shows that New England natural gas prices are expected to increase moderately, but will remain relatively low because of high levels of supply.[460]

Although wholesale natural gas prices are projected to remain low on average, price volatility has increased dramatically in recent years. Winter price spikes for natural gas during the 2011-2012, 2012-2013, and 2014-2015 heating seasons caused concurrent price spikes in the regional electricity markets.

Exhibit 13.6. The Wholesale Price of Natural Gas in Vermont 1989-2015 (2015 dollars)



Source: EIA.

Approximately 44% of net electric capacity in the region currently comes from natural gas generators.[461] The proportion of electricity generation from natural gas is expected to grow with the scheduled retirement of several large nuclear and coal plants. There is an inadequate supply of natural gas at the regional level during cold periods to maintain low and predictable prices for electricity. Several factors underlie this shortage. Pipeline infrastructure in the region is functioning at full capacity during many of the winter hours, with no room to ramp up supply during peak electric demand. The vast majority of natural gas generators do not have firm contracts with gas pipelines for delivery of fuel; as a result, these generators are not able to receive natural gas during periods of very cold weather when gas is being used for heating needs. Some generators can use oil or propane as an alternative, but these fuels are often much more expensive than natural gas and more polluting. Finally, there is very little natural gas storage capacity in the region, so generators cannot stock up when natural gas is abundant.

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[460] Ibid

[461] ISO New England, *Resource Mix*, www.iso-ne.com/about/what-we-do/key-stats/resource-mix

Increasing our use of renewable energy and decreasing our dependence on fossil fuels are important goals for Vermonters. Nevertheless, fossil fuel power plants are still a strategic component of the region's electric supply mix, because of their ability to produce a specific quantity of electricity at a designated time; and natural gas plants are meeting this need regionally. As we increase the amount of intermittent renewable energy in our portfolio, it will be important to ensure that we can meet Vermont's energy demand with resources that can guarantee delivery of electricity during periods of peak demand and low output from intermittent renewable energy.

13.2.4 Siting and Permitting

Siting and permitting of energy infrastructure is governed by 30 VSA § 248 (Section 248), which outlines criteria to ensure that development will promote the general good of the state. Permitting is a broadly focused process that takes into account economic benefits, environmental benefits and impacts, orderly development, and many other concerns. Siting concerns pertain to the proposed location of infrastructure and the potential impacts associated with the pipeline's construction and operation. Natural gas pipelines and associated infrastructure are evaluated under Section 248 to ensure the consistent and balanced review of economic, environmental, and reliability impacts. As with other sources of energy, siting of natural gas infrastructure should be undertaken with a thoughtful consideration of competing uses and energy needs.

Developers of new pipeline projects within the state must apply for a CPG from the PSB. Applications are evaluated by the PSB using standards outlined in Section 248. Pipelines crossing state borders are regulated by the Federal Energy Regulatory Commission, so any proposed pipelines connecting Vermont to neighboring states or to the regional pipeline system would fall under federal jurisdiction. Eminent domain may be applied to site pipelines that receive a CPG, and easements granted to pipelines include the right to conduct monitoring and maintenance.

Pipelines are buried underground, so visual and noise impacts are minimal. However, construction requires that a right of way be cleared and maintained, and that pipeline be laid. A portion of the right of way continues to be mowed and maintained for the life of pipeline, in order to prevent roots from woody vegetation from impacting the underground infrastructure.

In previous siting cases, parties have raised concerns about impact to agricultural soils, vegetative management on farms in pipeline corridors, and impacts to endangered or threatened species, significant natural communities, wetlands, and archeological sites. These concerns can be avoided or minimized by choosing pipeline routes that follow corridors already impacted by transportation or electric infrastructure, and through specific mitigation measures such as burying pipeline deep below agricultural soils, replacing topsoil after construction, routing around sensitive natural and historical areas, and drilling deep beneath wetlands and streams rather than trenching from the surface.

Compressor stations are required to maintain adequate pressure in the pipeline. Compressor stations are sited above ground and can have impacts on the surrounding area, including visual and noise impacts. Impacts may be remediated with screening and setbacks.

In 1994 VGS began a multi-year project to expand the capacity of its natural gas transmission system. The company added a loop from the U.S.-Canada border to Swanton, then on to St. Albans. In summer 2007, the company expanded its distribution system to make natural gas available to 650 homes and a number of businesses in Jericho village. The company subsequently expanded to Hinesburg and Underhill.

In 2012, VGS applied for a CPG to construct an extension of its pipeline network to bring service to Addison County. The expansion was approved by the PSB in late 2013, and construction is underway. Any future in-state expansion of the natural gas transmission pipeline network by VGS or other companies would undergo a rigorous process of review by the PSB.

13.2.5 Benefits

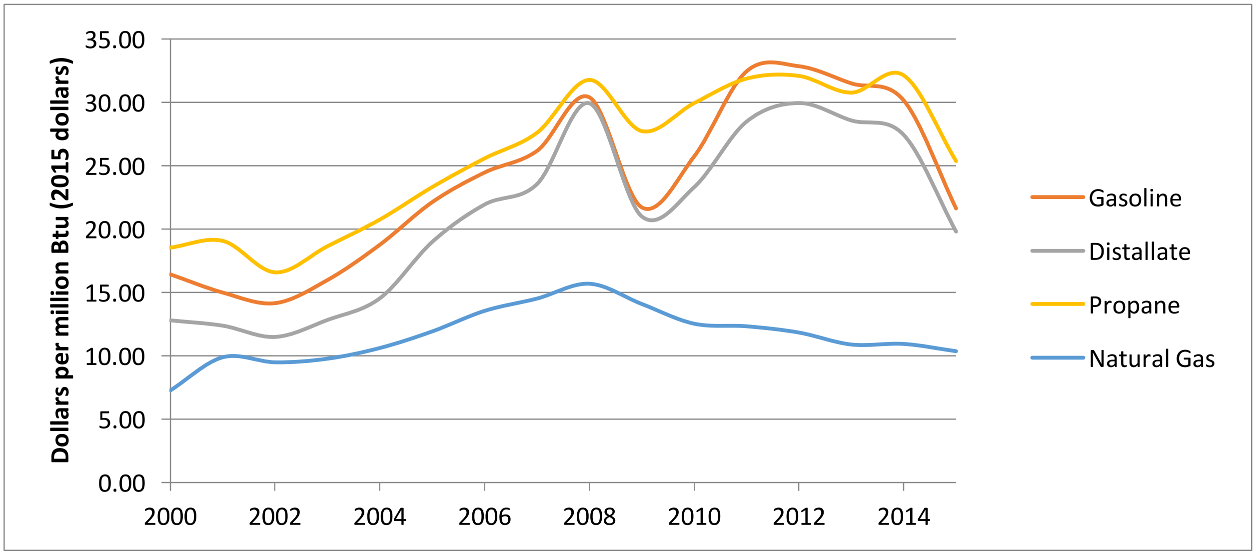
Natural gas is relatively clean and inexpensive when compared to other fossil fuels, and can be used in many applications where renewable sources cannot. Prices are expected to remain low. Because natural gas is inexpensive and stably priced relative to other fossil fuels, it offers a substantial economic development opportunity for communities that have access to pipeline infrastructure, and for large institutions using compressed natural gas delivered by tanker trucks.

The short-term impact of the expansion of natural gas infrastructure is to replace the heating oil and propane. Because natural gas produces less GHG than these fuels, switching to natural gas will provide a climate benefit.

Access to natural gas also allows for the economic diversification of energy supplies, and may provide economic development opportunities for businesses that rely on significant energy use for production. Many industrial processes require large amounts of energy delivered on demand, which is currently unrealistic for intermittent renewable energy sources. Natural gas has a significant role to play in ensuring an affordable and stable cost of living and for doing business in Vermont.

In strategic sectors where renewable energy is not feasible, market conditions will lead to opportunities for the replacement of oil and propane with natural gas. The recent growth of CNG is an example of these opportunities. In the long term, advanced liquid biofuels may offer an on-demand supply of transportable, energy-dense fuel; but in the short term, biofuels may not be economically competitive. Natural gas expansion offers an economic way to reduce carbon emissions.

Exhibit 13.7. Energy Price by Fuel Type, 2000-2015 (2015 Dollars)



Source: EIA[462]

Because gas can be burned whenever needed, it can provide energy on demand. In applications where renewable energy or efficiency cannot provide appropriate energy services, it is more desirable to use natural gas than other fossil fuels. These applications include providing reliable electric power when renewable sources are not generating, medium- and heavy-duty transportation, space heating where wood is impractical, and many industrial processes that require large amounts of heat.

Natural gas is generally delivered through pipelines. Because of the transportation involved, compressed natural gas delivered via tanker truck is more polluting than pipeline gas — but it is still less polluting than other fossil fuels that are also delivered by tanker truck. The price of trucked gas is unregulated, so it may be related to the price of competing oil fuel in addition to the price of pipeline gas. There are already several large customers in Vermont receiving compressed natural gas, including those at the Middlebury "gas island" being served by NG Advantage. In areas where pipeline infrastructure is not available or planned, and where manufacturing processes require large amounts of energy, the use of compressed natural gas may be preferable over other fossil fuels.

Efficiency

As a designated energy efficiency utility, VGS offers incentives to customers for higher-efficiency furnaces, boilers, water heating systems, and weatherization within its service territory. A 2015 study showed that that achievable potential for natural gas efficiency in Vermont was 8.2% by 2029 when

[462] U.S. EIA, *U.S. Overview*, www.eia.gov/state/seds/sep_prices/notes/pr_print2009.pdf

compared with a base-case scenario.[463] Natural gas furnaces can reach 95% efficiency, a higher level than any other combustion heating technology. Efficiency in equipment and in weatherization could significantly decrease gas usage in VGS's service territory. Expansion of the service territory of VGS would allow more Vermonters to take advantage of weatherization and efficiency incentives offered by VGS. Efficiency programs also offer the opportunity to hold overall growth in natural gas consumption to a lower level than otherwise would have occurred.

Renewable natural gas

In the long run, moving away from fossil natural gas will continue to be a priority. One part of this strategy is the development of renewable natural gas.

Biogas is the product of anaerobic digestion of organic material. It can be produced by various waste streams, including landfill material, manure, wastewater, and other organic waste including food scraps. Once carbon dioxide, water, hydrogen sulfide, and other trace elements have been removed, biogas becomes renewable natural gas and is chemically identical to fossil natural gas. It can be added to pipelines and used in end-use equipment without any modification to that equipment.

Capturing methane released by decomposing waste or manure and adding it to the pipeline system, to be used in homes and businesses, has substantial climate benefits. Methane has a global-warming potential 28 times more powerful than carbon dioxide over a 100-year time horizon (84 times more powerful on a 20-year time horizon).[464] Especially where methane would be released directly into the atmosphere were it not for capture operations, renewable natural gas projects offer a significant opportunity for climate change mitigation. A recent assessment by the National Renewable Energy Laboratory showed that 431 trillion Btu of renewable natural gas could be produced in the U.S., with significant potential existing in the North East.[465] In 2014, Vermont consumed about 9.7 trillion Btu of natural gas.

The cost of renewable natural gas is currently about twice the cost of fossil gas. As technology improves and economies of scale are achieved, renewable natural gas may become more affordable. Renewable natural gas procured from larger producers out of state is more affordable than locally produced gas because of economies of scale associated with large operations at landfills and wastewater treatment plants. Some renewable gas can be produced locally, keeping energy spending within the state. Building on the experience of using methane digesters to produce gas that is burned to generate electricity, entrepreneurs are developing methods to produce renewable gas and deliver it to large institutional

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[463] Optimal Energy, *Potential for Natural Gas Fuel Efficiency Savings in Vermont,* http://publicservice.vermont.gov/sites/psd/files/Topics/Energy_Efficiency/VT%202014%20Natural%20Gas%20Potential%20Study.pdf

[464] IPCC, *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]* p. 87*.* http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_FINAL_full.pdf

[465] U.S. G. Saur and A. Milbrandt, National Renewable Energy Laboratory, *Renewable Hydrogen Potential from Biogas in the United States,* http://www.nrel.gov/docs/fy14osti/60283.pdf

users, or directly into the pipeline system. One such project in Salisbury, which aims to serve Middlebury College, recently applied for a Certificate of Public Good from the Vermont Public Service Board.

An expansion of pipeline infrastructure and resulting use of more gas will raise consumption of this fossil fuel in the short term; but over the long term, the gas mix should include a rising percentage of renewable natural gas from digesters, landfills, and other renewable sources.

Connection to the U.S. pipeline system may also facilitate the purchase of renewable natural gas from areas outside Vermont. Although such large-scale projects are still years away, pipeline infrastructure lasts for decades, and could be used when renewable gas becomes more widely available.

13.2.6 Challenges

Natural gas raises the same environmental and economic concerns raised by other fossil fuels, including concerns about its long-term supply, sustainability, and high price volatility (although, because natural gas provided by VGS is hedges and provided via a tariffed service, the volatility of its retail price is dampened modestly compared with oil and propane).

Among fossil fuels, natural gas generally emits the lowest levels of almost all pollutants per unit of energy.[466] Nitrogen oxide emissions from natural gas are lower than from distillate fuel or wood use. Natural gas emissions are very low in sulfur oxides and low in particulates, carbon monoxide, and volatile organic compounds. Carbon dioxide emissions are significant; however, CO_2 emissions are lower than other fossil fuels.

Because methane, the primary component of natural gas, is a GHG much more potent than carbon dioxide, leakage from natural gas distribution systems can have serious environmental consequences. But the leakage rate from natural gas pipelines is estimated to be very small, and VGS's pipeline network is a relatively new system. The company has replaced all cast-iron and bare-steel mains, elements that are a significant source of leaks in other states. Going forward, care should be taken to continue to avoid methane leakage in any future distribution or transmission pipeline construction, and in the maintenance of the existing pipeline system.

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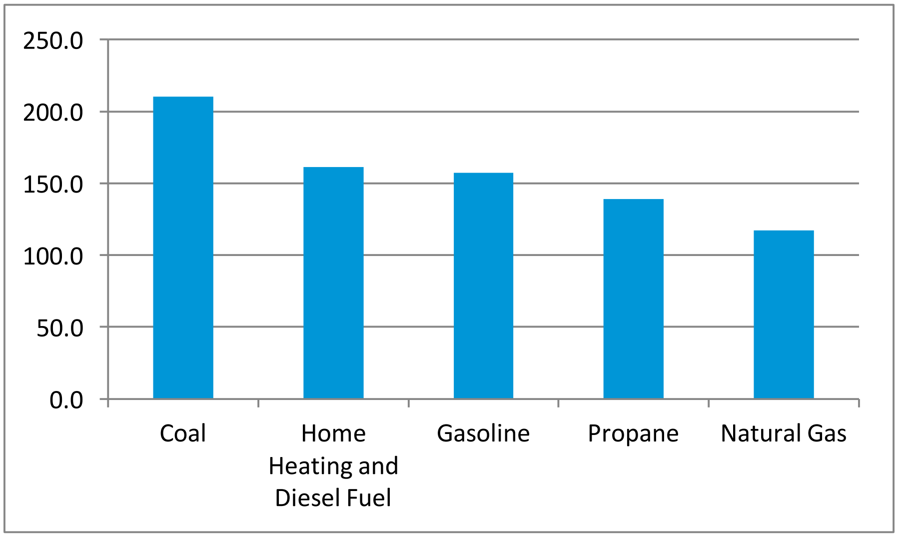
[466] U.S. EIA, *Natural Gas 1998: Issues and Trends*, www.eia.gov/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_and_trends/it98.html

Exhibit 13.8. CO_2 Emissions (lb/MMBtu)



Source: EIA[467]

Hydraulic fracturing is a technique used to extract natural gas from shale and tight sands by injecting water, sand, and chemicals under high pressure to release the gas. Hydraulic fracturing, when combined with horizontal directional drilling, has resulted in extensive new supplies of natural gas coming onto the market, a drop in price, and the decoupling of natural gas and oil prices. Low prices for natural gas — as well as a moderation in growth of electricity prices on the New England market — are a result of the increase in supply of natural gas related to hydraulic fracturing. Vermont Gas Systems obtains supplies from a variety of suppliers in Alberta and Ontario, Canada. It is currently not possible to track whether gas used in Vermont is extracted using hydraulic fracturing, because gas from several sources is mixed at the purchasing hubs where VGS obtains much of its gas.

When used without appropriate environmental controls, hydraulic fracturing can have negative impacts on water quality and air quality, and can result in significant fugitive methane emissions. There are many best practices and technical solutions to limit the impact of hydraulic fracturing to climate, air, land, and water. Natural gas companies in Vermont should pressure their suppliers to obtain gas from sources that use these best practices. The state should also work at the national level to improve environmental regulations pertaining to natural gas extraction.

Additional state or national regulations may emerge to mitigate the environmental impacts of shale gas extraction on groundwater, surface water, and air emissions. Recently released EPA regulations of

[467] Energy Information Administration, *Carbon Dioxide Emissions Coefficient*, *http://www.eia.gov/environment/emissions/co2_vol_mass.cfm*.

methane emissions in the extraction process will improve the overall environmental performance of natural gas.[468]

Strategies and Recommendations

Efficient and appropriate use of natural gas

Some fossil fuels are currently needed to provide reliable energy services on demand, and natural gas is the least expensive and least polluting fossil fuel option for many applications. Vermont can reduce the impact and extend the benefits of natural gas use by increasing natural gas efficiency and adding renewable natural gas, to the natural gas mix.

1) *Encourage expansion of pipeline gas infrastructure to enhance system reliability, reduce costs, and increase fuel choice for Vermonters, while recognizing that to meet the goals outlined in this plan, any expansion would require serious commitment to energy efficiency and renewable natural gas across the entire service territory.*

2) *In applications where wood or sustainable biofuels are not appropriate, natural gas is being used to move away from petroleum products, and pipeline gas is not available or planned, there is a role for the strategic and efficient use of compressed natural gas, transported via tanker truck, to play in advancing the economic and environmental goals of the state.*

3) *DPS should track trends in the use of compressed natural gas in both transportation and in natural gas "islands" or individual customers that are supplied by tanker truck.*

4) *The state should encourage the development of the renewable natural gas sector by supporting proposals for appropriately sited, cost-effective renewable natural gas production facilities and related infrastructure and supporting the cost-effective procurement of renewable natural gas to add to the natural gas supply.*

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468 EPA announced new regulatory actions pertaining to oil and natural gas extraction and processing on August 18, 2015. More information about these regulations is available at www.epa.gov/airquality/oilandgas/actions.html.

13.3 Coal

13.3.1 Overview

A small number of retail dealers supply coal to residential customers in Vermont for residential heat. Vermont does not consume any coal directly as a fuel source for the generation of electricity. However, there are several coal-fired electric-generating stations in New England — and because Vermont utilities purchase about 49% of their power from regional markets (after the sale of RECs is accounted for), coal is a source of electricity in Vermont. Vermont obtained 2.4% if its electricity from coal sources in 2013.[469] This number is likely to decline in the future.

Coal is one of the most polluting fuels available. It releases CO_2, CH_4, and N_2O, all GHGs contributing to climate change. Burning coal also emits NOx, SO_2, CO, lead, mercury, and particulate matter. These pollutants are known to cause severe health effects, including asthma, heart attacks, and other cardiovascular ailments.[470]

Coal to supply the New England grid is sourced from Virginia, West Virginia, and Pennsylvania, and as far away as Colombia, Venezuela, and Indonesia.[471] Because many of the region's largest coal-fired generating stations are located on the East Coast, they receive shipments by barge from all over the world on an open, unregulated market.

Historically, coal has accounted for a significant percentage of New England's generating capacity, though now for a variety of reasons its use is declining. In 2014, coal delivered 4% of the electricity consumed in New England, a sharp decline from 18% just nine years before in 2005. Coal cannot compete against other resources in an era of low natural gas prices, stricter federal environmental requirements for mercury and hazardous air pollution, slowing load growth, and aging plants. Two large plants are scheduled to go offline in 2017, Brayton Point and Salem Harbor in Massachusetts. Plants still in operation are running at greatly reduced capacity because natural gas is cost-competitive.

The federal Clean Power Plan, announced in August, 2015, sets reduced emission targets for coal and natural gas plants. States have some flexibility in meeting EPA goals, but the new rule could result in the closure of additional coal plants in New England. All the New England states except Vermont must comply with the Clean Power Plan. Vermont does not have any coal or natural gas fired stations, so has no obligations under the rule.

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[469] This is the most recent year for which data are available. For a more thorough discussion of how the sale of Renewable Energy Credits affects the mix of electricity purchased in Vermont, please see chapters 4 and 9.

[470] The EPA is charged with regulating these pollutants under the Clean Air Act. For more information: U.S. EPA, *What Are the Six Common Air Pollutants?,* www.epa.gov/airquality/urbanair/

[471] Appalachian Voices, *New England Power Plants that Use Coal and Where the Coal Comes From,* appvoices.org/resources/maine-legislation/Data-on-New-England-Power-Plants-Coal-Use-2008.pdf.

13.4 Nuclear

13.4.1 Overview

Nuclear electric generation from existing nuclear plants provides affordable, reliable baseload power, and continues to be an important source of electric energy for Vermont. Several Vermont utilities have entered into long-term power purchase agreements with Seabrook Nuclear Station in New Hampshire, to procure capacity as well as energy. Green Mountain Power owns a 1.7% share of the Millstone 3 nuclear generating unit in Connecticut. Although no new nuclear facilities are expected, nuclear continues to be a key resource, providing power to the New England grid as well as to Vermont utilities. Vermont's only nuclear facility, Vermont Yankee, was disconnected from the grid and manually shut down in December 2014.

13.4.2 Resources

At present, four nuclear power plants with a total capacity of 4,026 MW operate within the New England grid, supplying roughly 29% of the energy used by the region in 2014, the most recent year for which data are available. These units are operating nearly round the clock, with a 90% capacity factor. Nuclear energy will constitute slightly less of New England's use in 2015, when the retirement of Vermont Yankee will be reflected in the data. Vermont Yankee provided about 4% of the region's power in 2014. Low natural gas prices in the region have led to cost-competitive gas-fired plants taking over an increasing market share from traditional baseload sources.

The Millstone 3 nuclear unit in Connecticut, of which GMP owns 1.7%, is a 1,155 MW plant, first operational in 1986, that has received an extended operating license through 2045. Historically, Millstone has supplied about 5% of GMP's supply requirements.

GMP and the Vermont Electric Cooperative both have long-term power purchase agreements with the Seabrook Nuclear Station, from which GMP expects to obtain about 500,000 MWh annually. In 2015, both utilities have also contracted for capacity from Seabrook to offset their obligation in the regional forward capacity markets. In total, GMP plans to receive about 10% of its power from nuclear in the near term. Vermont Electric Cooperative has a contract with Seabrook Nuclear Station to purchase about 80,000 MWh annually.

13.4.3 Benefits

Nuclear power provides Vermont utilities with low-carbon, stably priced energy and capacity. Unlike intermittent renewable sources, nuclear power stations provide low-carbon electricity nearly around the clock. Outages for maintenance and refueling are known well in advance, so grid operators can plan for them. In an era when capacity prices on the New England market are rising, nuclear can offer stably priced capacity to meet utility obligations.

13.4.4 Challenges

There is no national solution for the permanent storage of radioactive spent nuclear fuel. Spent fuel is stored in pools built of concrete and lined with steel for a minimum of three years, where it continues to cool in water. Following this period, fuel is moved into dry casks at individual nuclear stations. Both storage pools and dry cask systems are regulated by the Nuclear Regulatory Commission (NRC).

The possibility of a nuclear disaster, however remote, is a lingering specter for the nuclear industry and for communities surrounding nuclear facilities. Following a severe nuclear accident at the Fukishima Daiichi facility in northeastern Japan in 2011, emergency preparedness was called into question at nuclear plants in the U.S. In 2013, the NRC released a series of new rules to enhance safety at nuclear facilities — including additional measures pertaining to individual and multi-reactors, spent fuel pools, flooding, and seismic protection. Public safety remains a high priority at nuclear facilities, including Vermont Yankee, where spent fuel remains in its pool and dry-cask storage even though the plant is offline.

Entergy Nuclear has requested an exemption from federal requirements to conduct emergency planning within a 10-mile radius of the Vermont Yankee plant beginning in 2016. The state opposed the exemption, and litigation before the NRC is ongoing.

13.4.5 Site Decommissioning and Restoration

Vermont Yankee is located in Vernon and is owned by Entergy Nuclear Vermont Yankee LLC, a subsidiary of Entergy Nuclear Operations, Inc. A decommissioning fund established during its operation will cover the financial expenses of dismantling the plant and decontaminating the property. The NRC regulates the decommissioning process. As of this writing, Entergy Vermont Yankee plans to employ a deferred dismantling plan, whereby structures are left in place and the plant is maintained until its radioactivity decays. Then the plant will be disassembled and the site decontaminated.

In a resolution of longstanding litigation, the state and Entergy Vermont Yankee reached a settlement in December 2013. Entergy agreed to restore the site to support use of the property "without limitation" following radiological decommissioning.[472] A separate fund was established for this purpose. Because the site continues to be an active storage location for spent nuclear fuel, around 250 staff members will continue working there until 2020, when Entergy hopes to complete moving spent fuel to dry cask storage. The dry-cask storage units will remain in place until a national solution to the storage of spent nuclear fuel is settled. Dry-cask storage areas are exempt from the restoration requirement of the settlement.

[472] The complete text of the Memorandum of Understanding between the DPS and Entergy Vermont Yankee is available at psb.vermont.gov/sites/psb/files/docket/7862Relicensing6/Docket_7862_MOU.pdf.

Strategies and Recommendations

(1) *Vermont utilities and agents that are party to the negotiations of major contracts for nuclear power or capacity should help ensure that the smaller municipal and cooperative utilities gain access to those resource contracts on similar terms and conditions.*

(2) *The state should continue to advocate for effective oversight of all safety aspects of Vermont Yankee by the U.S. Nuclear Regulatory Commission.*

(3) *The state should continue to advocate for an appropriate and effective federal solution to the problem of spent nuclear fuel stored on site.*

(4) *The state should work to ensure that Entergy funding of environmental monitoring and emergency preparedness is sustained as Vermont Yankee proceeds with decommissioning activities.*

14 State Agency Energy Plan

14.1 Introduction

The State of Vermont is committed to supporting Vermont's transition to a healthy and prosperous clean energy future, by reducing energy use and improving energy efficiency in its own facilities and operations, and by increasing the share of energy it gets from renewable sources.

State government is one of the largest institutional energy users in Vermont. It is the third-largest employer; state agencies occupy more than four million square feet of building space, and own and operate more than 1,800 vehicles. As one of Vermont's largest energy users, state government has an important role to play in demonstrating how public- and private-sector organizations from across the state can contribute to meeting Vermont's energy and climate goals, while also saving money and creating desirable workplaces well-positioned to recruit and retain top talent from Vermont and beyond.

This State Agency Energy Plan (SAEP), prepared by the Department of Buildings and General Services with input and guidance from the Governor's Climate Cabinet and support from state agency staff, lays out a road map for how state government can lead by example as we implement Vermont's Comprehensive Energy Plan and make progress toward ambitious energy goals for 2025, 2035, and 2050.

14.1.1 Purpose of the State Agency Energy Plan and Individual Agency Energy Implementation Plans

Authorized in legislation passed by the Vermont Legislature in 1992, the SAEP serves as a guiding document for Vermont state agencies when making decisions about energy in state government operations. The SAEP must be updated every sixth year subsequent to 2010. An update to the 2010 SAEP was incorporated into the 2011 Comprehensive Energy Plan as the State Agency Energy Leadership chapter. The 2016 SAEP will be published both as an integral chapter of the CEP and as a separate document.

The inclusion of the SAEP within the CEP clarifies state government's intent to demonstrate the institutional goals and actions that will contribute to a rapid transition to a clean energy future for Vermont and allows the SAEP to become a formal state agency leadership section within the larger plan.

The 2016 SAEP includes:

1. Clear and measurable energy goals for state government in three areas: a) reductions in total energy consumption across all facilities and operations; b) expansion of the share of state energy that comes from renewable sources such as solar, wind, high-efficiency biomass, and

hydroelectric power; and c) reductions in state government emissions of greenhouse gases that cause climate pollution.

2. A profile of Vermont state government's current energy use, highlighting improvements made in recent years.

3. A road map — including recommended strategies and action steps — that state government will use to make progress in different sectors, such as building energy use, distributed generation of renewable power, and reductions in fossil fuel use for transportation.

4. A recommended process for implementing this road map and making progress toward the SAEP's energy goals across state agencies, including steps for tracking, documenting, and reporting progress.

The plan focuses on near-term, actionable items that can be implemented now to meet the state's goals.

Individual agency actions to manage energy use and invest in energy improvements will be coordinated with this SAEP. Each state agency is also required to prepare a biannual Agency Energy Implementation Plan (AEIP) that aligns with the SAEP and provides more detail on agency-specific goals and recommended actions. Current plans are scheduled to be updated during 2016.

The 2016 SAEP was produced by the Department of Buildings and General Services in close consultation with an inter-agency staff group called the State Operations Working Group (SOWG). It is the objective of the SOWG to establish a coherent and consistent plan based on the array of obligations, responsibilities, legal mandates, and authorities that have been established relative to energy in state government operations.

As noted above, the State Operations Working Group consulted closely with the Climate Cabinet during the development of this plan. Established by Executive Order in 2012, the Cabinet is composed of state-agency secretaries, commissioners, and other senior officials, and is charged with providing comprehensive leadership of the state's climate change initiatives, including initiatives to reduce greenhouse gas emissions and reliance on fossil fuels, and to improve the state's resilience to the current and future impacts of climate change. The Climate Cabinet will provide oversight and direction as the SAEP is implemented during the next six years.

14.1.2 Statutory Authorization for the Plan

The SAEP was established in Title 3 V.S.A. § 2291 — State Agency Energy Plan. Relevant language can be found in Appendix C. The statute outlines the following objectives to be accomplished by the plan:

(1) Conserve resources, save energy, and reduce pollution;
(2) Consider state policies and operations that affect energy use;

(3) Devise a strategy to implement or acquire all prudent opportunities and investments in as prompt and efficient a manner as possible;
(4) Include appropriate provisions for monitoring resource and energy use and evaluating the impact of measures undertaken;
(5) Identify education, management, and other relevant policy changes that are a part of the implementation strategy;
(6) Devise a strategy to reduce greenhouse gas emissions; and
(7) Provide, where feasible, for the installation of renewable energy systems.

14.2 State Government Energy Goals

The 2016 SAEP puts forth the following goals to establish state government's commitment to demonstrating leadership in Vermont's transition to clean energy and showing the diverse economic, environmental, and social benefits that this transition will yield for public and private institutions across the state. State leaders in the Climate Cabinet agree that demonstrating leadership should include reaching state energy and climate goals on an accelerated timeline.

The SAEP's goals therefore challenge state government to reduce total energy consumption by a greater percentage by 2025 than sought in the corresponding CEP goal, expand the share of total energy the state gets from renewable sources by a greater percentage by 2025 than the corresponding CEP goal, and achieve greenhouse gas emissions reductions relative to these goals. The specific goals are:

- Reduce total energy consumption by 20% by 2025, and by 25% by 2035.
- Meet 35% of the remaining energy need from renewable sources by 2025, and 45% by 2035.
- 40% reduction of greenhouse gas emissions below current levels by 2030.

14.2.1 Basis for the SAEP Goals

Total Energy Reduction

The Legislature asked in 2011's Act 40 that every agency, board, department, commission, committee, branch, or authority of the state reduce its energy consumption, including the amount of fuel used by its employees to travel to and from meetings during the workday, by 5% each year. The Legislature also asked that state government increase the amount of renewable energy used by the state.

The critical intent of Act 40 complements Title 3, summarized above, which requires that the energy needs of the state be met in a manner that reduces greenhouse gas emissions. However, if state government were to achieve a 5% reduction in energy consumption annually, total energy consumption would be reduced from fiscal year 2015 by 40% in 2025, and over 80% by 2050. Reductions of this magnitude are likely not feasible given current economic conditions, technologies, and funding.

This SAEP proposes a goal for reducing total energy use that we believe is achievable given current state programs and funding sources — namely a 20% reduction in total energy consumption by 2025, including energy used to power and heat state buildings as well as energy associated with transportation by employees. This goal is at approximately the same scale as the all-economy goals put forth in the Comprehensive Energy Plan, while still challenging state government to lead by example by achieving a greater energy reduction.

Using Renewable Energy

The SAEP's renewable energy goal is also a good stretch goal, accounting for the progress made so far but also requiring considerably more investment in a transition to renewable sources of power. Vermont state government has already made good progress toward achieving the 2050 renewable energy goal adopted in the 2011 Comprehensive Energy Plan; in FY 2015, total energy consumption was 23% renewable. This progress has been achieved in large part through the successful implementation of net metered solar projects, and an increased use of woody biomass for heating. Progress has also been facilitated by the increasing share of renewable energy in the energy portfolios of the utilities that provide electric power for state operations.

Twenty-eight percent of the electric power distributed by Vermont's grid is generated from renewable sources. Finally, the 7% ethanol component of gasohol, or gasoline with added ethanol, now delivered at fuel pumps has helped increase the state's use of renewable energy.

Without relying on renewable energy supplied by the grid, state government increased its usage of renewable energy by 12% over the last four years. In FY 2015, the state used more wood products than oil for heating, and will continue to do so now that the two largest heat plants in state government, at the Montpelier Capital Complex and the Waterbury State Office Complex, are primarily fueled by wood chips.

Due to this progress, state government is on track to meet 35% of its energy needs from renewable sources by 2025 and 40% by 2030.

Greenhouse Gas Emissions

Based on a simple analysis conducted with the Center for Corporate Climate Leadership's GHG emissions calculator tool, state government was responsible for over 80,000 metric tons of CO_2 equivalent emissions (MMtCO_2-e) in FY 2015. If state government achieves the total energy reduction and renewable energy goals set forth in this plan, it will reduce greenhouse gas emissions associated with state government operations by at least 40% by the year 2030.

14.2.2 Sector-Specific SAEP Targets

State government should plan to make changes in all areas of operations in order to achieve these overall goals for reductions in energy consumption, improvements in energy efficiency, and increases in the share of energy consumption using renewable sources. This section provides a sector-by-sector synopsis of what state agencies can do to help meet these goals. Additional guidance on the kinds of actions that can and will be pursued to meet these goals is in the Strategies and Recommendations section.

Improving Building Energy Conservation and Efficiency

To meet the SAEP's goals for reductions in total energy consumption, state agencies must improve electric and heating efficiency within state buildings (especially those that are state-owned, but also those that are leased), in addition to conserving more energy through changes in practices. In total, these gains in efficiency and conservation should reduce fuel usage by 15% by 2030, to support progress in meeting the state's overall energy use reduction goal. Funding is available for energy retrofits through the State Energy Management Program (SEMP). The Department of Buildings and General Services (BGS) energy team, in partnership with Efficiency Vermont, is available to provide technical assistance to agencies that wish to implement efficiency measures in their buildings. Visit bgs.vermont.gov/energy for more information.

Heating with Renewable Fuels

Meeting state government's renewable energy goals will require using more renewable fuels to heat buildings, along with continuing to increase the use of electricity generated from renewable sources. When building new state facilities, or when replacing heating equipment that has reached the end of its useful lifespan, state agencies switching to high-efficiency systems that rely on woody biomass will support progress toward our energy goals.

In addition, when new heating systems are not being purchased, switching to liquid biofuels for use in conventional heating systems, if and when available, will also increase the state's use of cleaner, renewable fuels. Specifically, the share of liquid bio-heating oil used for heating should rise from 0% in 2015 to 5% by 2020, and 25% by 2035.

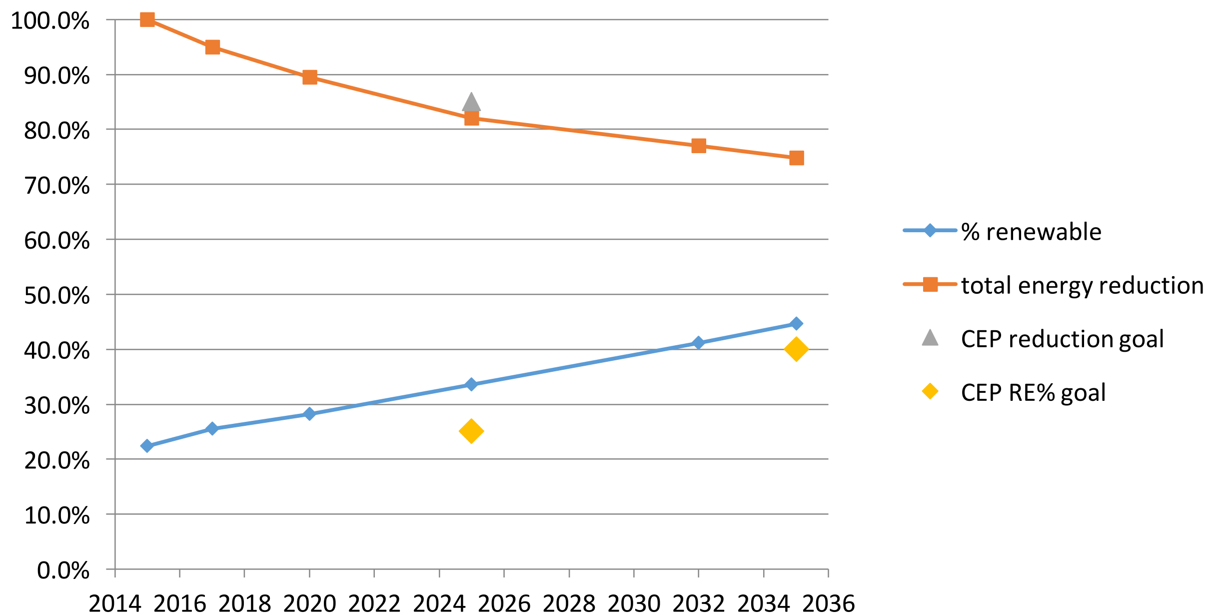
Using Alternative Fuels for Transportation

The energy that state agencies use for transportation must also shift if state government is to reach its near- and long-term energy goals. Specifically, the diesel fleet should increase the use of biodiesel from 0% in 2015 to 5% in 2020 and 25% by 2035. State agencies will also need to meet more of their transportation needs with electric vehicles. Specifically, miles powered by electricity in plug-in hybrid vehicles and all-electric vehicles should achieve a level sufficient to displace 10% of the state's current gasoline use by 2020, 25% in 2025, and one-third by 2032. The Go Green Fleets Initiative currently being launched by BGS (and described in the Recommendations section) is designed to achieve and surpass this goal.

In summary, state government must increase energy efficiency to reduce building energy usage by 15%; increase the use of biodiesel and bio-heating oil from 0% in 2015 to 5% by 2020, and 25% by 2035; and reduce state gasoline use by 10% in 2020, 25% in 2025, and one-third in 2032.

Exhibit 14-1 models a trajectory for energy reduction and renewables within state government if these changes occur. CEP goals are indicated for comparison, showing that the state is committing to lead by example.

Exhibit 14-1. SAEP Energy Reduction and Renewable Energy Trajectory



14.3 Recent Energy Improvements and Current Energy Use in State Government Operations

14.3.1 Summary of Accomplishments

Since the last SAEP was published six years ago, state government has made great strides in all areas of energy improvement, through the development of new funding sources, through investments in energy retrofits and renewable energy technologies for buildings and transportation, and through outreach and education for state managers and employees. Examples follow; further detail is provided in the Strategies and Recommendations section.

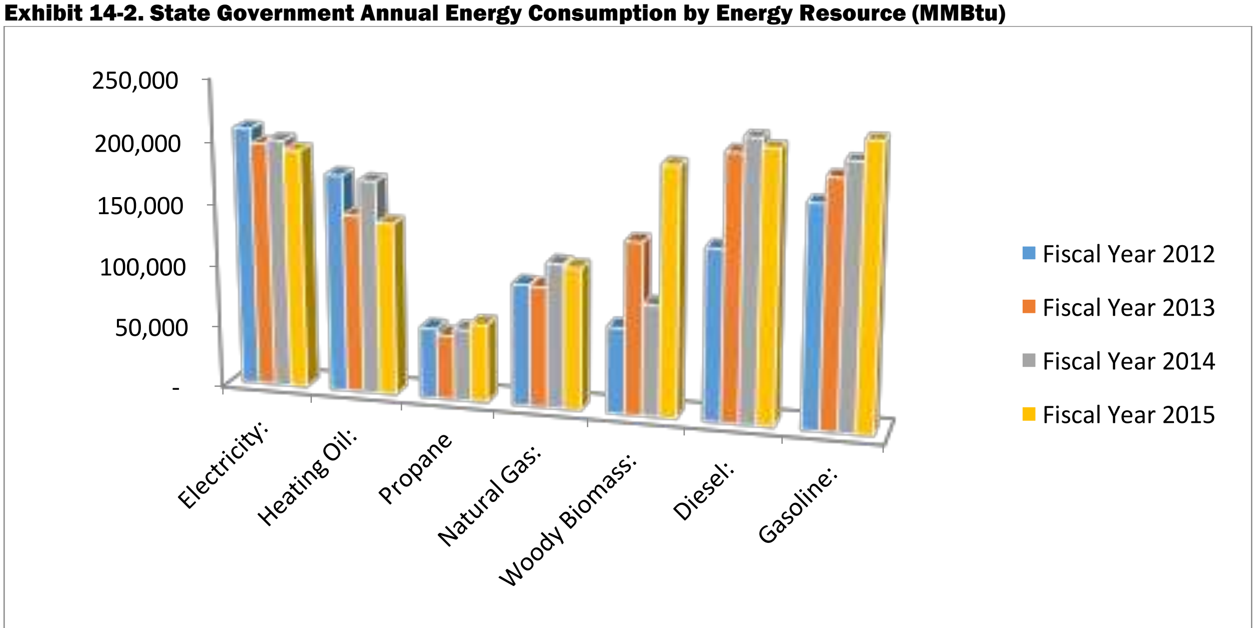
- State agencies have improved their buildings through weatherization, lighting upgrades, fuel switching away from fossil fuels, and toward alternative fuels like woody biomass, building controls optimization, and other various energy efficiency and conservation measures.
- State government has developed new funding mechanisms, and has partnered with Efficiency Vermont to provide dedicated staffing for a new State Energy Management Program to help advance this progress.

- Agencies are utilizing the Energy Star Portfolio Manager to track building energy usage and rate their buildings in comparison to similar types of structures nationally.
- The Fleet Management Program has managed to increase the efficiency of on-the-job employee travel by providing fleet vehicles to high-mileage state employees, rather than paying the higher cost of mileage reimbursement. Fleet Management Services has also established a systematic approach for supplementing the fleet motor pool with plug-in hybrid electric vehicles, to decrease fossil fuel consumption and the associated air emissions.
- Agencies are utilizing the WEX Fuel purchasing system to aggregate transportation energy data, to better manage state government transportation.
- Agencies and departments throughout state government have increased renewable biomass and solar photovoltaic usage in state government operations.

14.3.2 Recent History of Energy Use in State Government Operations

In fiscal year 2015 state government consumed 1,239,517 million Btu of energy. Total energy consumption has increased annually by over 7% on average from FY 2012. Transportation energy accounts for this increase. In fiscal year 2015, gasoline accounted for 27% of all energy consumed by state government, more than any other energy resource consumed over the same period. (Exhibit 14-2)

Exhibit 14-2. State Government Annual Energy Consumption by Energy Resource (MMBtu)



Transportation

Gasoline and diesel combined accounted for 45% of the total energy mix in FY 2015. This is a 28% increase in transportation energy from FY 2012. The transportation energy data used to derive these percentages includes gasoline consumption associated with all state government fleet vehicles, mileage reimbursement for travel in employee-owned vehicles, and diesel consumption associated with the operation of the Vermont Agency of Transportation (VTrans) diesel fleet.

While transportation energy has increased, building energy consumption has decreased. Requirements to improve building energy efficiency through retrofit practices such as weatherization and lighting upgrades, and through new building construction practices, are well-established within state government operations. Electric vehicle technology, on the other hand, is relatively new, is only available for light-duty vehicles, and has only recently been incorporated into the state's motor pools and become available for state employee use. The opportunities to limit gasoline usage across all state transportation have therefore been more limited.

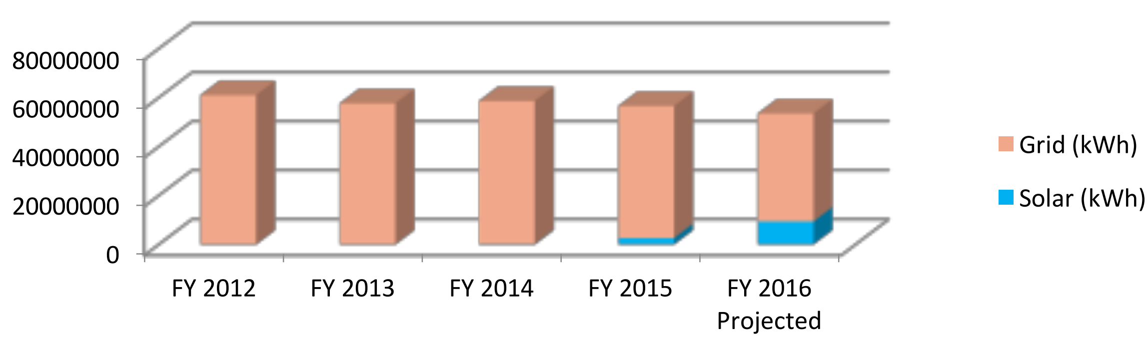
Buildings

In FY 2015, energy associated with state-owned buildings made up 55% of the total energy consumed through state government operations. While we have managed to decrease the amount of electrical consumption associated with our building stock and increase the amount of renewable energy consumed from FY 2012 to FY 2015, our oil and natural gas consumption has either increased or remained relatively steady during this period. This demonstrates a need to continue the state's focus on improving electrical efficiency, while also increasing our focus on thermal energy efficiency initiatives.

Renewable Energy

In 2012, state government had no solar photovoltaic projects associated with its electric utility accounts. In 2016 there will be over six megawatts of solar production capacity as a result of state government projects; if electricity consumption continues to decrease, these projects will offset total electrical consumption by 17% in 2016. (Exhibit 14-3). Woody biomass for state government building heating energy has increased by 17% from 2012. In FY 2015 the state used more wood products than oil for heating.

Exhibit 14-3. State Government Annual Electricity Consumption (kWh)



Greenhouse Gas Emissions

Emissions of greenhouse gases (GHGs) associated with state government operations have increased by 3% since 2012, but from 2014 to 2015 they decreased by 4%. In the buildings sector, GHG emissions have decreased slightly due to an increase in renewable energy consumption and a reduction in overall electricity usage, while transportation-related GHG emissions have increased due to an increase in gasoline and diesel consumption.

Energy Data Disclaimer

The energy data used in this plan was derived from aggregated government-wide energy expenditures, which have been converted to units of energy using average electricity costs and state fuel contract pricing. This data omits energy consumption associated with space leased to the state, because that information is not readily available. The data is meant to provide an indication of how much energy is consumed by state government, in order to create a baseline against which we can measure progress toward our goals.

14.4 Strategies and Recommendations

While development and implementation of the SAEP is the responsibility by statute of the secretary of administration through the Department of Buildings and General Services, BGS has involved all agencies, through the inter-agency State Operations Working Group and the Climate Cabinet, in the development of the strategies and recommendations laid out below. The continuation of this collaboration, with a new focus on getting to work and overcoming obstacles to achieving goals and realizing energy improvements, is strongly recommended. Specific strategies for structuring this collaboration are included in Section 14.5.

14.4.1 Strategies and Actions for State-Owned and Operated Buildings, Construction Practices, and Leased Space

14.4.1.1 Make Use of Available Funding and Technical Assistance to Improve Energy in State Buildings

In 2015, the Legislature approved funding for the Department of Buildings and General Service to establish a new, comprehensive State Energy Management Program (SEMP). The purpose of this program is to help agencies across state government identify, fund, and manage projects that will make state buildings more efficient and power them with renewable energy. The program will also encourage operational practices (e.g., turning off the lights) that can dramatically reduce the energy consumed in state buildings.

The SEMP oversees two revolving loan funds to provide low-cost financing for energy management measures in state buildings and facilities. All state agencies and departments may apply to fund energy projects using these funds. The State Resource Management Revolving Fund (SRMRF) and the State Energy Revolving Fund (SERF) are available for resource conservation measures, energy efficiency improvements, and the use of renewable resources. These funds were created to eliminate barriers to funding to up-front costs of efficiency improvements that yield significant cost savings once completed. They will make diverse projects in state buildings fundable, and in the process will help to make progress toward the state's energy goals while also saving Vermont taxpayer funds.

Since the creation of the SRMRF in 2004, over 70,000 MMBtu and over $1.2 million have been saved. Additional projects have received funding and will soon be constructed. If no further investments are made, the fund is projected to save over $2.1 million through avoided energy expenditures by 2020.

The SEMP has established the goal of investing $4 million in energy improvements over the next four years through the two revolving loan funds. If this target is reached, state government will save an estimated $800,000 annually over the next 20 years — roughly $16 million in total energy savings. If the SEMP meets this investment target, the projected energy savings will reduce building energy consumption by 12% from 2015 totals. BGS estimates that the SEMP could invest an additional $4 million by 2025 above these initial goals, resulting in an estimated 14% reduction in total energy consumption.

In 2015 the Vermont Legislature passed ACT 58, Sec. E.112, Energy Efficiency; State Building and Facilities, which requires BGS (with support from Efficiency Vermont) to scale up work performed by the SEMP for a preliminary period of four years to deliver energy and dollar savings to state government. Efficiency Vermont will provide adequate funding to support the creation and maintenance of BGS's SEMP team (including three full-time positions) during the four-year preliminary period.

BGS and Efficiency Vermont have committed to collaboratively supporting and managing the SEMP. By working in close partnership, BGS and Efficiency Vermont will leverage each organization's strengths, experience, and resources toward meeting the established goals. Significant work will take place in the period of this plan to identify and launch energy efficiency projects in state-owned buildings. The partnership will also address space that is leased by the state, through discussions with building owners about the improvements they could make for a major tenant of their buildings.

A first step will be to increase the number of state facility and operations managers that are actively measuring progress in reducing energy use against a measured baseline. The SEMP team and Efficiency Vermont are available to help state agencies use the U.S. Environmental Protection Agency's energy tracking tool, Energy Star Portfolio Manager, to analyze current energy consumption and establish a baseline for assessing progress.

Agency Energy Implementation Plans

All state entities are required to produce an implementation plan with actionable items specific to their operational energy consumption. These plans and the process to develop them can create an important opportunity for analyzing current trends in agency energy use, setting agency-specific goals, and identifying good cost-effective projects that can be financed with these revolving loan funds and assisted by the SEMP team if desired. There is significant assistance available to agencies as they move forward with the highest-value energy efficiency and renewable energy improvements that can be made in state buildings.

Recommendations

(1) State agencies should work with the SEMP team to gather and analyze current energy use using EPA's Energy Star Portfolio Manager for buildings.

(2) All state agencies that occupy state-owned buildings should identify and prioritize further opportunities to improve their energy efficiency. Many projects have already been completed and are saving state taxpayer money. When needed, state agencies should utilize services provided by the SEMP to expand their capacity for planning cost effective projects, organizing financing, and managing the construction process. For more information, go to bgs.vermont.gov/energy.

(3) State agencies should also evaluate opportunities to construct renewable energy facilities and participate in net metering on facility sites where possible. Sites should be carefully selected to ensure the protection of natural resources and to minimize visual impacts for site neighbors.

14.4.1.2 Implement Energy-Saving Construction Practices

The BGS Design Guidelines are meant to help architectural and engineering firms better understand state government construction standards. The guidelines were last updated in 2013, and are due to be updated again in 2016. BGS adheres to the commercial and residential building energy codes required by the state, and works with partners to achieve higher standards when practical.

When starting new construction or renovation projects, state agencies can contact Efficiency Vermont for technical support. When technical advisors from Efficiency Vermont provide guidance during the earliest phase of a project, they can often help to ensure that opportunities to improve building energy efficiency during design and construction are maximized, and that the necessary construction work for efficiency improvements proceeds efficiently, without obstacles and delays.

BGS currently considers meeting the energy standards necessary to secure the U.S. Green Building Council's LEED, or Leadership in Energy & Environmental Design certification, on all new construction projects. However, BGS does not *require* that projects meet these standards and become certified. According to the U.S. Green Building Council, LEED is a green building certification program that recognizes best-in-class building strategies and practices. To receive LEED certification, building projects must satisfy certain prerequisites associated with each different levels of certification and earn the corresponding points. Prerequisites and credits differ for each rating system, and teams choose the best fit for their project. Projects can receive a LEED Certified, LEED Silver, LEED Gold, or LEED Platinum certification depending on the number of points achieved.

State government currently has one LEED Silver-certified building, the Pittsford Training Academy, and one LEED Gold-certified building, the Bennington District Court and Office Building. The Waterbury State Office Complex is on target to become state government's first LEED Gold-certified campus.

The LEED certification process focuses on many areas of sustainability, including downtown designation. Locating state government operations in downtown areas helps build strong local economies, and reduces transportation energy by increasing walking, cycling, and transit opportunities. The commissioner of Buildings and General Services and all other state officials have been asked by the Legislature to locate state government functions such as new buildings in downtown areas when suitable. Title 24 § 2794 (12).

BGS is statutorily required to utilize life-cycle cost analysis when considering the use of renewable energy sources, energy efficiency, and thermal energy conservation in any new building construction or major renovation project in excess of $250,000. In accordance with this procedure, the *life-cycle cost* of each new building construction or major renovation project shall mean the net total of the present-value purchase price of all items used, plus the replacement cost, plus or minus the salvage value, plus the present value of operation and maintenance costs, plus the costs or benefits of the energy and environmental externalities.

Recommendations

(1) All state agencies should utilize BGS Construction Guidelines when constructing or renovating state facilities, and should adopt higher standards wherever possible given project budgets.

(2) All agencies should work closely with BGS and local municipalities to find a suitable downtown location for their operations when considering new construction, if appropriate.

(3) State agencies are encouraged to assess the life cycle costs of potential energy improvements — including long-term cost savings — during design and construction planning. The National Institute of Standards and Technologies' Building Life Cycle Cost Program offers free calculation tools to help analyze potential capital investments in buildings. The SEMP team can offer assistance on life-cycle cost evaluation as well.

14.4.1.3 Reduce Energy Use and Improve Efficiency in Leased Space

In 2015, state government leased 1,044,281 square feet of space. This is a 41% increase in leased space from 2011, signaling a growing need to advocate with building owner/operators for energy efficiency and renewable investments in buildings that the state does not own.

In 2014 the Legislature passed Act 178, Section 40, Energy Efficiency; State Leases, requiring the commissioner of Buildings and General Services to develop a set of criteria and guidelines to evaluate and, where appropriate, incorporate the use of energy efficiency measures, thermal energy conservation measures, and renewable energy resources in buildings and facilities leased by the state. In response to this legislative mandate, BGS developed Operations Procedures for Energy in Leased Space.

Many agencies occupy leased space and do not have the ability to directly implement energy conservation measures associated with their space. There is a need to develop guidelines for state employees to follow when occupying leased space, in order to reduce the overall energy impact of state government. In response to this need, the State Operations Working Group proposed an Agency Energy Implementation Plan template for those agencies occupying leased space. This template should consist of specific actions that all agencies can adopt and build on to reduce their energy impact.

Recommendations

(1) *BGS should develop an Agency Energy Implementation Plan (AEIP) template for all state agencies whose operations are housed in leased space.*

(2) *All agencies whose operations are housed in leased space are encouraged to adopt and use the BGS AEIP template.*

(3) *Agencies should work closely with BGS to find leased space in downtown areas when considering new or additional leases.*

14.4.2 Strategies and Recommended Actions for Transportation

State government is committed to demonstrating fleet management and investment practices that reduce energy use and emissions from transportation. In FY 2015, state government consumed over 2.7 million gallons of gasoline, including gasoline consumption associated with state-employee mileage reimbursement, and over 1.6 million gallons of diesel. Actions to meet new goals for reducing state gasoline use and increasing the use of biodiesel and bio-heating oil from 0% in 2015 to 5% by 2020 and 25% by 2035 are summarized below.

The Fleet Management Program managed by the Department of Buildings and General Services is reducing the overall cost of employee travel and reducing greenhouse gas emissions by right-sizing its fleet. *Fleet right-sizing* is a management practice that can help vehicle fleet managers build and maintain sustainable, fuel-efficient fleets. Fleet inventories can include vehicles that are highly specialized, rarely used, or unsuitable for current applications. By optimizing fleet size and composition, managers can minimize vehicle use, conserve fuel, and save money. For more information, see www.afdc.energy.gov/conserve/rightsizing.html.

Another key initiative during the last several years has been to add plug-in hybrid electric vehicles to the state motor pool. Electrifying the state fleet addresses a key priority in Vermont's Zero Emission Vehicle Action Plan and a Multistate Zero Emissions Vehicle Plan that Vermont has committed to help implement. These initiatives are fully described in the Comprehensive Energy Plan.

Since 2007, Fleet Management Services has been purchasing plug-in hybrid vehicles for the motor pool. As of 2015, 24% of the vehicles in the state's central motor pool are plug-in hybrid electric vehicles; 13 of the 55 vehicles are EVs. The environmental and cost benefits of this transition are significant. Other state agencies that maintain their own vehicles have also leased plug-in hybrids. As all-electric vehicles — which run entirely on electricity, and can drive longer distances without being charged — improve, they will replace the plug-in hybrids to maximize the electric miles driven while meeting state transportation needs.

Additionally, as electrification of the fleet has progressed, the state has accelerated the installation of charging infrastructure needed to power these vehicles and maximize their electric miles. Eight new dual-port level 2 charging stations have been installed at fleet headquarters in Montpelier, allowing FMS to charge 16 vehicles at once. BGS has also recently procured vendor services on a statewide contract to provide electric vehicle charging equipment to state government. The Fleet Management Program is also reducing costs and emissions by providing efficient fleet vehicles to high-mileage state employees, rather than paying the higher cost of mileage reimbursement.

The program has been very successful at reducing mileage reimbursement. Gasoline consumption associated with mileage reimbursement has decreased by 28% from FY 2012, although total gas and diesel consumption have increased.

In the next five years, the Fleet Management Program and all state agencies must collaborate to make more progress on right-sizing fleets, continuing the transition to electric vehicles (including new all-electric vehicles with longer ranges), and reducing employee travel.

Following are the state's strategies and recommendations for achieving these energy improvements in state transportation.

14.4.2.1 Launch the Go Green Fleets Initiative

Starting in 2016, the state will launch a new *Go Green State Fleets Initiative* to formalize and demonstrate its commitment to low-carbon and clean-energy transportation. This initiative will help agencies lead by example in the transition to greener fleets and fleet practices that save taxpayer funds and reduce energy use and greenhouse gas emissions. The initiative will also recognize the many ongoing efforts by state agencies to green their fleets and fleet practices, and will support progress toward state energy and climate goals. The initiative will be coordinated by the Department of Buildings and General Services.

While state government has made good progress in electrifying its fleet, currently only 4% of the total fleet of 300 light-duty vehicles (including those leased by individual agencies from BGS) are plug-in hybrid electrics. This percentage rises to roughly 20% if both plug-in and conventional hybrids are counted. In order to convert an additional 21% of the state's light-duty fleet by 2025 and meet the goal in the Vermont ZEV action plan, all state agency fleets have to incorporate electric vehicles.

Converting a much larger percentage of state government's light-duty fleet to electric is an attainable goal: the technology is available, the vehicles are affordable, and the investment in vehicles and infrastructure is cost-beneficial to the state. The medium- and heavy-duty fleet engine technology is becoming more efficient, but there are currently no viable electric options for these size vehicles. Several agencies, including large agencies such as ANR and VTrans, have agreed to join the Go Green Fleets Initiative and make plug-in hybrid electric and all-electric vehicles available to employees for on-the-job travel. When electric models are not practical or available, the Go Green Fleets Initiative will also encourage state agencies to lease the most fuel-efficient vehicles possible.

Many of the state's heavy-duty vehicles are operated by VTrans and ANR. The modernization of these fleets is underway, ensuring more efficient and cleaner-burning equipment. New federal requirements will require improvements in heavy-vehicle fuel efficiency. In addition, the 2012 and newer heavy duty on-road vehicles have significantly reduced NOx emissions. At VTrans, the majority of vehicles and equipment are within their cost-effective service period — and stable funding remains a challenge for the agency, making early replacement of vehicles before the end of their service period difficult.

Finally, the initiative will mobilize strategies to encourage trip planning and driving practices that reduce energy use and air and climate pollution emissions. For example, VTrans is launching a new project to install Automated Vehicle Location (AVL) systems in all agency plow trucks and some other fleet vehicles. These systems provide easy tracking, reporting, and analysis of idling. Better and more accessible data should allow for better management and resulting efficiencies. This pilot may produce lessons that can be implemented in the central motor pool and other state fleets.

Recommendations

(1) All state agencies should work toward meeting the goal adopted in the Vermont ZEV Action Plan — to make 25% of light-duty state fleet vehicles electric by 2025. The Fleet Management Program should continue working with agency operations staff to identify opportunities to add more plug-in hybrids, and new all-electric vehicles with longer ranges, to the central motor pool and to agency fleets where they are well-matched to transportation needs. BGS should also work to familiarize agency leaders and employees with the new electric vehicles through Ride and Drive events, training videos, and other means as capacity allows.

(2) BGS and state agency leaders and operations staff should encourage and support the use of electric vehicles by state employees, and should encourage trip planning and mobility practices that reduce fuel use and the associated air emissions. Go Vermont should be a key partner in this effort.

(3) BGS should build charging infrastructure to service the state's growing EV fleet, and make that infrastructure accessible to the public where possible. BGS should continue to lead efforts across state government to right-size fleets, by optimizing vehicle size and composition to conserve fuel and save money.

(4) BGS and VTrans should consider lessons from the project to install AVL equipment in VTrans plows and other vehicles, to reduce idling more broadly across the state fleet.

(5) BGS should establish systems for tracking and reporting on progress in this Go Green fleet transformation and its environmental and cost benefits.

14.4.2.2 Increase the Use of Biodiesel in Transportation

To reach the renewable energy goals and greenhouse gas emissions goals of the SAEP, state government will have to seriously consider the use of biodiesel blends when possible. At present, 55% of total state government transportation energy is attributable to the Vermont Transportation Agency (VTrans), including over 95% of diesel consumption. All original-equipment manufacturers warranty their engines for use with B5, a blend of 5% biodiesel and 95% petroleum diesel. Some manufacturers warranty their engines for use with B20, a blend of 20% biodiesel and 80% petroleum diesel. The National Biodiesel Board keeps a list of manufacturer warranties on its website, biodiesel.org/using-biodiesel/oem-information/oem-statement-summary-chart.

VTrans currently has 144,500 gallons of diesel storage capacity. As fueling facilities with underground tanks reach their end of useful life, VTrans is not replacing them, due to the life-cycle cost relative to using retail locations to pump diesel. According to the Vermont Clean Cities Coalition (VCCC), there is currently only one gas station in Vermont that has biodiesel available at the pump.

For those locations that still have storage tanks, VTrans can purchase B5 from the state; but it will take a greater effort to make biodiesel readily available at gas stations throughout Vermont.

VCCC plans to convene a Vermont biodiesel working group in 2016 to start tackling the issues of biodiesel adoption in the state. The adoption of biodiesel use in the VTrans fleet will help to support the state's overall efforts.

Recommendations

(1) VTrans should increase its purchase of biodiesel from state fuel-purchasing contracts for those facilities that have diesel storage tanks.

(2) All agencies that purchase diesel fuel for transportation purposes should use the highest biodiesel blend available without compromising the manufacturer's engine warranty. All manufacturers fully warranty their engines with the use of B5, a blend of 5% biodiesel and 95% diesel.

14.4.2.3 Reduce On-the-Job Transportation and Solo Commuting by State Employees

The most efficient way to reduce energy consumption in state transportation is to reduce on-the-job travel when possible, by identifying unnecessary travel and requiring teleconference and ridesharing when appropriate. This can be accomplished by better understanding and tracking agency light-duty vehicle use and encouraging ridesharing and teleconference and videoconference use. State employees in some agencies could use better access to video conferencing.

Although telecommuting will not directly affect the goals stated in this plan, a considerable amount of energy is consumed by state employees commuting to and from work. Policy 11.9 — Telework, issued by the Department of Human Resources and approved by the secretary of administration, establishes the basic principles and conditions regarding employee requests to work remotely from an alternative worksite. All agencies are encouraged to promote this policy when appropriate. As the third-largest employer in Vermont, state government could help motivate the broader use of telecommuting among Vermont organizations, by demonstrating its value and good policies and practices to manage it.

Another way to reduce state government-related transportation is to encourage and incentivize employees to use public transit services when available to commute to work. The state Go Vermont program, administered through VTrans, provides commuting alternatives for all employees in Vermont, among which state employees are a big part. Go Vermont connects rideshare participants, administers vanpool programs, and is a convenient portal to state transit programs.

In 2012, the state agencies agreed that increasing the use of Go Vermont's services by state employees should be a priority, and Montpelier was selected as the site for a pilot project to provide state employees with incentives for using rideshare, transit, and other mobility options. The original intent was to reduce parking pressures at the Capitol Complex. In July 2013, the Capital Commuters program was launched. This three-year pilot project, managed within the Go Vermont program, offers discounted bus passes, preferential carpool and vanpool parking, local business discount cards, and a "guaranteed ride home" benefit to state employee participants. It has helped to spur increases in the use of public transit by state employees and significant environmental benefits. (See table below and Case Study in Appendix D for more detail.

Environmental Savings (Annual)	Results: Total Activity	Results: Activity attributed to CC Program
Annual total miles	2,264,856	607,200-1,214,400
Gallons of gas (Ave. 26 MPG)	87,109 gallons	23,353-45,707 gallons
CO_2 (19.4 lbs. per gallon)	1,689,914 lbs./845 tons	453,048 lbs.-906,096 lbs.
Cost ($2.50 per gallon)	$217,773	$58,383-$116,765

These initial efforts cost roughly $120,000 and were supported by federal and state funds. VTrans has been covering the discounted bus-pass costs using state funds. July 2016 will mark the end of the three-year pilot, with strong indications that the Capital Commuters program will be made permanent. Starting in FY '16, each state agency must contribute the amount necessary to cover the bus-pass costs for its respective employees. Between July 2013 and June 2015, a total of $244,900 has been spent on the passes, and total annual costs are projected to be between $130,000 and $150,000.

Recommendations

(1) *State agencies should work with BGS as part of the Go Green Fleets Initiative described above, to consider ways to monitor light-duty vehicle use and reduce unnecessary state employee travel where possible.*

(2) *State agencies should seek to provide employees with the necessary equipment and training to facilitate conference calls, webinars, and other virtual meetings and information sharing.*

(3) *State agencies should adopt and implement Policy 11.9 on telework, and should share the lessons they learn as they implement it about how to support telework without causing any significant impacts to the productivity or quality of state employee work.*

(4) *To maintain and increase state employee participation in the Capital City Commuters program, beginning in FY '16 state agencies should fund the costs of public-transit passes for their employees who already*

participate in the program or would like to participate. In addition, state agencies should work with VTrans' Go Vermont program to explore ways of extending similar services and incentives to other state work sites outside of Montpelier.

14.4.3 Strategies and Recommended Actions for Renewable Energy Use at State Facilities

In fiscal year 2015, the state's energy profile was over 17% renewable without accounting for any renewable energy that state agencies purchase from the grid. Roughly 27% of energy consumed by state government is projected to be renewable by the end of 2016 as a result of several new initiatives:

- Agencies have recognized the importance of becoming less dependent on fossil fuel for heating, and have taken advantage of modern wood-burning technology to heat state buildings with biomass.
- Agencies have taken advantage of Vermont's solar net metering law to implement cost-effective solar projects.
- Implementation of the new renewable energy standards established in ACT 56, which require electric power provided by Vermont's utilities to be 55% renewable by 2017 and 75% renewable by 2032, will significantly increase the percentage of electricity purchased for use by state buildings that comes from renewable sources.

The use of renewable energy at state facilities can grow further to meet state government's energy goals through implementation of the following strategies and recommended actions.

14.4.3.1 Fully Implement the State Government Solar Initiative

Photo of the Southeast State Correctional Facility in Windsor, VT
Courtesy of AllEarth Renewables

The state is currently under contract with AllEarth Renewables to provide a cost-effective strategy to increase the state's renewable energy portfolio. Through this contract, BGS and the Department of Corrections have entered into 10 group net metering contracts that, when completed, will create almost five megawatts of solar power capacity and reduce greenhouse gas emissions by over 4,000 tons of carbon dioxide. These projects will offset all the electricity consumed by state correctional facilities and numerous state office buildings throughout Vermont. The state pays no upfront cost, and receives a reduced electric bill every month.

Other agencies are also taking advantage of net metering to green their facilities and reduce electricity costs. The Department of Buildings and General Services contracted for a roof-mounted system at the Waterbury Office Complex, making it the first state owned building to incorporate roof-mounted solar panels. The Department of Fish and Wildlife and VTrans are also utilizing Vermont's solar net metering law to build fixed panel arrays at various locations. These panels generate electricity that is purchased by Vermont utilities at a rate that will make the projects financially beneficial over time. (See case studies in Appendix D for more detail on these projects.)

Recommendations

(1) BGS and other state agencies should pursue additional opportunities to contract with solar businesses specializing in roof-mounted systems similar to the new system at the Waterbury State Office Complex.

(2) State agencies should work to incorporated solar photovoltaic panels into the built environment wherever feasible, and should work closely with advisors at the Agency of Natural Resources and the Agency of Agriculture, Food & Markets to ensure that:

- *Projects are sited in appropriate locations that comply with natural resource and flood hazard regulations and guidelines.*
- *Projects are designed and built with practices that minimize natural resource impacts and visual impacts for neighboring properties.*
- *Projects are not built on prime agricultural soils, and best practices are used to ensure soil health and vitality.*

14.4.3.2 Increase the Use of Modern Wood Heating with Biomass

The state has increased its use of high-efficiency wood heating systems in recent years through a variety of projects at different scales.

The Montpelier district heat plant was rebuilt in 2014, and now primarily burns wood chips with No.2 heating oil backup. This is projected to reduce the amount of oil burned in the plant by over 80%, and reduce greenhouse gas emissions by 1,500 tons per year. The heat plant serves the entire Capital Complex. Through a partnership with the City of Montpelier, the district heat plant is able to distribute hot water to city customers that have opted to connect to the city's hot water loop.

A new Waterbury heat plant constructed at the new Waterbury Office Complex is now fully operational, and will burn wood chips for the majority of the heating season with propane backup. The old Waterbury heat plant was the last location at which the state was still burning No. 6 heating oil, which produces more greenhouse gas emissions than propane and No. 2 heating oil. The environmental benefits for state operations in Waterbury will be similar to those in Montpelier.

Other recently completed projects are also reducing emissions and increasing the state's use of renewable wood energy:

- The Barre District Courthouse had been retrofitted with an efficient wood heating system. Pellet boilers now heat the building instead of an old electric resistance boiler. This project is expected to save over 230 tons of carbon dioxide emissions per year.
- The Northern State Correctional Facility, Northeast Regional Correctional Facility, and Southeast State Correctional Facility all burn logwood to heat their facilities.
- The VTrans Enosburg Garage, Derby District Garage, Barton Garage, Brighton Garage, Canaan Garage, Irasburg Garage, and Westfield Garage all burn cordwood that is primarily sourced from roadside cleanup and maintenance tree cutting.

The Comprehensive Energy Plan includes new goals for promoting the use of woody biomass in modern heating systems; however, the plan also emphasizes that this resource must be harvested in a sustainable way to ensure that the increased use of biomass does not harm the health of Vermont's forests.

On January 15, 2015, the commissioner of the Department of Forests, Parks and Recreation (FPR) adopted a set of voluntary harvesting guidelines for private landowners to help ensure long-term forest health and sustainability. The guidelines were developed in response to Act 24, which was passed by the Vermont Legislature in 2013. These guidelines were not yet adopted when BGS released the latest RFP for wood biomass for the state purchasing contracts, but they are now available to guide future purchase of wood heating products for use in state operations.

Recommendations

(1) The state should continue to replace older oil-fired heating systems with new, modern, clean wood product-burning heating systems. BGS should target the largest oil-consuming locations, and should prepare cost-benefit

analysis studies that consider the cost of replacement relative to energy savings and environmental benefits. The age and useful life of the existing heating systems should be weighted when determining which projects to undertake first.

(2) *Agencies responsible for buildings heated with oil should contact the BGS Energy Manager to obtain information and discuss further options available to switch to a biomass heating system. The Biomass Energy Resource Center is also a great resource, available through Vermont Energy Investment Corporation, for all agencies interested in biomass for their facilities.*

(3) *All agencies should ensure that wood products purchased for use in state building heating systems are sourced from forests that are managed in accordance with ANR's voluntary harvesting guidelines for private landowners.*

14.5 Implementing the State Agency Energy Plan

This plan is the product of close collaboration across state agencies. The State Operations Working Group, which assisted BGS with the development of the analysis, strategies, and recommendations, includes representatives of many state agencies and departments — including VTrans, the Agency of Natural Resources, the Department of Public Service, the Agency of Agriculture, Food & Markets, the Agency of Commerce & Community Development, and the Department of Corrections.

The State of Vermont is committed to supporting Vermont's transition to a healthy and prosperous clean energy future by implementing this plan and meeting the goals it sets forth for state government's use of energy. Continuing coordination and collaboration across state government through regular meetings of the State Operations Working Group and through oversight and guidance by the Climate Cabinet will ensure our success.

Within individual agencies, identifying the best projects to pursue through the development of action-oriented Agency Energy Implementation Plans and through work with the SEMP team is critical to making progress towards energy goals. In addition, agencies should specify roles and responsibilities among agency staff members for finding opportunities and making energy-related improvements to state facilities and operations. VTrans has found that periodic meetings among staff working on energy improvements really drives progress.

Finally, celebrating success will help keep us all motivated.

Abbreviations Used

ACCD: Vermont Agency of Commerce & Community Development
AEIP: Agency Energy Implementation Plan
AEV: all-electric vehicle
AMI: advanced metering infrastructure
AMP: Acceptable Management Practice
ANR: Vermont Agency of Natural Resources
ANSI: American National Standards Institute
ARRA: American Recovery and Reinvestment Act
ASTM: American Society for Testing and Materials
ATFS: American Tree Farm System
AVL: automatic vehicle locator/location
BED: Burlington Electric Department
BGS: Vermont Department of Buildings and General Services
BOD: biological oxygen demand
BPI: Building Performance Institute
Btu: British thermal unit
CAFE: Corporate Average Fuel Economy
CAP: Community Action Partnership
CBES: commercial building energy standards
Ccf: hundred cubic feet (of natural gas)
CEDF: Vermont Clean Energy Development Fund
CEDO: Community Economic Development Office
CEED: Community Energy and Efficiency Development
CEP: Comprehensive Energy Plan
CESA: Clean Energy States Alliance
CFL: compact fluorescent lighting
CHP: combined heat and power
CGC: Coalition for Green Capital
CO: carbon monoxide
CO_2: carbon dioxide
CNG: compressed natural gas
COO: Certificate of Occupancy
CPG: Certificate of Public Good
CPP: critical peak pricing, or Clean Power Plan
CVPS: Central Vermont Public Service
CVR: conservation voltage regulation
DC: direct current
DEC: Vermont Department of Environmental Conservation

DER: distributed energy resource
DEV: Drive Electric Vermont
DG: distributed generation
DOE: U.S. Department of Energy
DOE-OE: U.S. Dept. of Energy's Office of Electricity
DPS: Vermont Department of Public Service
DR: distributed resources
DSM: demand-side management
DU: distribution utility
DUP: distributed utility planning
EAN: Energy Action Network
EEC: energy efficiency charge
EEM: energy efficient mortgage
EEN: Efficiency Excellence Network
EEU: energy efficiency utility
EIA: U.S. Energy Information Administration
EIM: energy improvement mortgage
EISA: U.S. Energy Independence and Security Act
EPA: U.S. Environmental Protection Agency
EROEI: energy return on energy invested
ESA: Efficiency Service Agreement, or Energy Savings Account
ESCO: energy service company
ESPC: energy service performance contracting
ESPM: ENERGY STAR Portfolio Manager
EU: European Union
EUI: energy use intensity
EV: electric vehicle
EVT: Efficiency Vermont
FEMA: Federal Emergency Management Agency
FCEV: fuel cell electric vehicle
FCM: Forward Capacity Market
FDIR: fault detection isolation and recovery
FERC: Federal Energy Regulatory Commission
FIA: U.S. Forest Inventory and Analysis National Program
FPR: Vermont Department of Forests, Parks & Recreation
FSC: Forest Stewardship Council
FTE: full-time equivalent
GEMS: Green Energy Market Securitization
GHG: greenhouse gas
GMP: Green Mountain Power
GT: geotargeting
GW: gigawatt
GWh: gigawatt-hour(s)

GTFS: General Transit Feed Specification

HEPA: high-efficiency particulate arrestance

HERS: Home Energy Rating System

HHV: higher heating value

HQ: Hydro-Quebec

HSIPR: high-speed and intercity passenger rail

HVAC: heating, ventilation, and air conditioning

HWAP: Home Weatherization Assistance Program

IECC: International Energy Conservation Code

IHD: in-home display

IRB: interest rate buy-down

IRP: integrated resource plan/planning

IPP: independent power producer

ISO-NE: Independent System Operator of New England

ITC: Investment Tax Credit

kBtu: thousand Btu

kW: kilowatt

kWh: kilowatt-hour(s)

LBNL: Lawrence Berkeley National Laboratory

LDC: line-drop compensation

LEAP: Long-Range Energy Alternatives Planning, or Logger Education to Advance Professionalism

LEED: Leadership in Energy and Environmental Design

LIAC: Local Investment Advisory Committee

LiDAR: combining "light" and "radar," a remote sensing technology

LIHEAP: Low-Income Home Energy Assistance Program

LNG: liquefied natural gas

LPG: liquefied petroleum gas

LTC: load tap changer

MDMS: meter data management system

MESA: Managed Energy Service Agreement

MLP: master limited partnership

MLS: Multiple Listing Service

MMBtu: million Btu

MPG: miles per gallon, or Municipal Planning Grant

MOU: memorandum of understanding

MW: megawatt

MWH: megawatt-hour(s)

NDA: Neighborhood Development Area

NECPUC: New England Coalition of Public Utility Commissioners

NEGECP: Northeastern Governors and Eastern Canadian Premiers

NEIL: Nuclear Electric Insurance Limited

NEPOOL: New England Power Pool

NEPOOL GIS: New England Power Pool Generator Information System

NERC: North American Electric Reliability Corporation
NESCAUM: Northeast States for Coordinated Air Use Management
NESCOE: New England States Committee on Electricity
NHTSA: National Highway Traffic Safety Administration
NICE: Northeastern International Committee on Energy
NOx: nitrous oxide
NRC: Nuclear Regulatory Commission
NRCS: Natural Resources Conservation Service
NREL: National Renewable Energy Laboratory
NRG: Renewable NRG Systems, a Hinesburg, Vt. company
NTA: non-transmission alternative
NYPA: New York Power Authority
OATT: Open Access Transmission Tariff
OEO: Vermont Office of Economic Opportunity
PACE: Property Assessed Clean Energy
PAH: polycyclic aromatic hydrocarbon
PHEVS: plug-in electric hybrid vehicles
PLC: power line carrier
PM: particulate matter
PPA: power purchase agreement
PPESCO: public purpose energy service company
PSB: Vermont Public Service Board
PTC: production tax credit
PURPA: Public Utility Regulatory Policies Act
PV: photovoltaic
QA: quality assurance
QECB: Qualified Energy Conservation Bond
QPI: quantifiable performance indicator
RBES: residential building energy standards
REAP: U.S. Dept. of Agriculture's Rural Energy for America Program
REC: Renewable Energy Certificate
REIT: real estate investment trust
RES: Renewable Energy Standard
REV: New York’s Reforming the Energy Vision process
RF: radio frequency
RFP: request for proposals
RGGI: Regional Greenhouse Gas Initiative
RGGR: Regional Greenhouse Gas Registry
RIN: renewable identification number
RINA: rare and irreplaceable natural area
RLF: revolving loan fund
RMI: Rocky Mountain Institute
RNS: regional network service

ROI: return on investment
RPC: Regional Planning Commission
RPS: renewable portfolio standard
RTE: rare, threatened, and endangered
RTP: real-time pricing
SAEP: State Agency Energy Plan
SCADA: supervisory control and data acquisition
SCFM: standard cubic feet per minute, a measure of gas flow
SEMP: State Energy Management Program
SERF: State Energy Revolving Fund
SFI: Sustainable Forestry Initiative
SHPO: State Historic Preservation Office
SHW: solar hot water
SO_2: sulfur dioxide
SOP: single-occupancy vehicle
SOWG: State Operations Working Group
SPEED: Sustainably Priced Energy Enterprise Development
SRMRF: State Resource Management Revolving Fund
SSREI: Small Scale Renewable Energy Incentive
SSREIP: Small Scale Renewable Energy Incentive Program
SQRP: service quality reliability plan
TCI: Transportation Climate Initiative
T&D: transmission and distribution
TEF: Thermal Energy Finance
TES: Total Energy Study
TETF: Thermal Efficiency Task Force
TIMO: timberland investment management organization
TOU: time of use
TREES: total renewable energy and efficiency standard
TW: terawatt
TWh: terawatt-hour(s)
USDA: U.S. Department of Agriculture
UVM: University of Vermont
VAAFM: Vermont Agency of Agriculture, Food & Markets
VAR: volt-ampere-reactive
VCCT: Vermont Clean Cities Coalition
VCET: Vermont Center for Emerging Technologies
VEC: Vermont Electric Cooperative
VECAN: Vermont Energy and Climate Action Network
VEDA: Vermont Economic Development Authority
VEIC: Vermont Energy Investment Corporation
VELCO: Vermont Electric Power Company
VEPP: Vermont Electric Power Producers

VFDA: Vermont Fuel Dealers Association
VFEP: Vermont Fuel Efficiency Partnership
VGS: Vermont Gas Systems
VHCB: Vermont Housing and Conservation Board
VHFA: Vermont Housing Finance Agency
VLCT: Vermont League of Cities & Towns
VMT: vehicles miles traveled
VLITE: Vermont Low Income Trust for Electricity
VPPSA: Vermont Public Power Supply Authority
V.S.A.: Vermont Statues Annotated
VSECU: Vermont State Employees Credit Union
VSPC: Vermont System Planning Committee
VTrans: Vermont Agency of Transportation
VTWAC: Vermont Weather Analytics Center Project
VVC: volt/VAR control
WAP: Weatherization Assistance Program
WEC: Washington Electric Cooperative
WHEEL: Warehouse for Energy Efficiency Loans
WLEF: Working Lands Enterprise Fund
ZEV: zero emission vehicle
ZEV MOU: Zero Emission Vehicle Memorandum of Understanding

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Appendix A: Power Sector Transformation in Other States

New York

Under the direction of the governor and the Public Service Commission, New York in 2014 initiated Reforming the Energy Vision, a formal investigation into power sector transformation. Under New York REV, the Public Service Commission is attempting to align markets and the regulatory landscape with policy objectives of giving customers new opportunities for energy savings, local power generation, and enhanced reliability to provide clean, and affordable electric service.[1] The PSC seeks to "reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets."[2] The NY PSC established two tracks for the efforts, the first track focused on markets and the second on ratemaking reforms. These will be brought together in future orders.

In January 2015, the New York Department of Public Service determined that "platform" refers to the Distribution System Platform role articulated by the PSC to describe how markets for electricity-related products and services would develop.

The Commission issued a major order on February 26, 2015, adopting a Regulatory Policy Framework and Implementation Plan ("Track 1 Order"). The Public Service Commission determined in its track one order that the distribution utility will provide the Distribution System Platform. However, the PSC made it clear that if competitive distortions arise, they will revisit this determination.

The next phase of the REV process involved stakeholder efforts. The New York Department of Public Service required staff of the department to convene and coordinate stakeholder working groups including representatives of the New York State Smart Grid Consortium (NYSSGC), and other closely related groups addressing market design and platform technology. This group became the Market Design and Platform Technology (MDPT) Committees.

The working groups were tasked with the following:

- Consider the next level of detail around market design and platform technology needed to move towards the DSP vision in the near term;
- Make recommendations on key market design and platform technology elements (e.g., DSP functions and responsibilities, products to be exchanged, required standards, etc.) needed in the near term and provide reports to the commission; and

[1] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

[2] New York State Department of Public Service. 2014. Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision - DPS Staff Straw Proposal on Track One Issues at 3.

- Provide guidance on these issues to inform utility Distributed System Implementation Plans (DSIPs).

The MDPT issued a draft report on July 15, 2015.[3]

Among the recommendations of the report are the following:

- Enhanced distributed planning: The MDPT proposes that distribution system planners improve analytical capabilities related to DER hosting capacity, identify the locational net value of DER at specific geographic locations on the grid, and identify and prioritize locations where DER should be pursued to provide distribution system capacity and operational relief.
- Market access, platform, and distribution system optimization: Market access here refers to the elements of reform that enable and encourage markets and customer active participation by reducing barriers, increasing access to information, and leveraging the resources of the distribution utility to facilitate these things.

These topics cover fairly comprehensive and more detailed list of the areas covered and a reference point for the market-related actions and proceedings that are occurring in other states listed above. Other topics that are part of the New York process and typically enter into the larger set of issues around policy and regulatory environments necessary to foster effective use of DERs include the following:

- Rate design: This issue often arises in connection with issues around maximizing the value of DER. Dynamic rates and designs that provide incentives for controlled loads offer considerable potential to better match flexible loads with variable energy resources. Rate design and ratemaking issues are part of the track two process in New York.
- Access to the grid: Similarly, access and interconnection are of great importance in light of the considerable interest in connecting rooftop PV and other resources. Concerns for the stability of the grid sometimes weigh against interconnection in areas with high penetration of PV.
- Business models, incentives, cost recovery and performance-based regulation: How utilities recover costs and are incented to recover costs is of considerable interest as regulators look to encourage utility practices to conform to objectives for DER resources. Business models and incentive regulation are part of the track two process in New York.
- Demonstration projects: Examples of these changes working effectively on the ground are needed to advance the framework for optimal use of DERs. In a December 12, 2014 order, the PSC encouraged the investor owned utilities to partner with third party energy entrepreneurs to undertake demonstration projects that would further the REV vision. Developed in cooperation with universities, local government and local groups, utility demonstration projects were proposed for approval on July 1, 2015. Seven of the proposals were approved for further development.

[3] https://newyorkrevworkinggroups.com/wp-content/uploads/MDPT_Draft-Report_07.15.2015_final.pdf

California

California launched an effort in 2014 pursuant to legislative direction.[4] The state's investor-owned utilities are required to file Distribution Resource Plans with the California PUC to better integrate distributed energy resources onto the grid.[5] These plans were filed July 1, 2015 and will be under review for some time. Unlike some other jurisdictions, this particular California process does not focus on issues such as the business model or cost recovery.[6] However, there is a list of parallel efforts around the broader set of issues that are implicated by an investigation into power sector transformation. Included in these are incentives and mechanisms to encourage market access from distributed generation and customer-side generation,[7] rate design proceedings have resulted in direction to utilities on rate submissions in the coming 5 years,[8] and proceedings related to alternative-fueled vehicles.[9]California's single state ISO is also working with the PUC on aligning wholesale and retail markets to improve the value of demand response.

What stands out in the California efforts is the use of Distribution Resource Plans. The plans filed with the commission address the infrastructure issues as well as many of the issues covered in the New York REV process, including rate design, data access, among others.[10]

Hawaii

Hawaii has the highest electricity rates in the US and good solar resource potential. Rooftop solar in Hawaii has been leading the US in the rate of adoption while also presenting challenges both to the utility intent on maintaining system quality, and customers who would like to participate in programs and capture the value of rooftop PV. In August of 2014, Hawaii opened a major investigation to "investigate the technical, economic, and policy issues associated with distributed energy resources ('DER') as they pertain to the electric operations of" its major electric utilities.[11] The investigation followed the public release of a commission white paper that presented the leanings of the Hawaii Public Utility Commission. The white paper that sets up the investigation covers a wide range of potential reforms, including in the areas of rate design, utility business models and incentives, data access, grid modernization, and planning.[12]

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[4] Assembly Bill 327.

[5] California Utility Cost 769

[6] RMI Outlet, New York and California are Building the Grid of the Future, February 18, 2015, available at http://blog.rmi.org/blog_2015_02_18_new_york_california_building_the_grid_of_the_future

[7] http://www.cpuc.ca.gov/PUC/energy/DistGen/

[8] http://www.cpuc.ca.gov/PUC/energy/Electric+Rates/

[9] http://www.cpuc.ca.gov/PUC/energy/altvehicles/

[10] California Public Utilities Commission, Distribution Resource Plans, viewed on August 21, 2015 and available at http://www.cpuc.ca.gov/PUC/energy/drp/

[11] Public Utility Commission of Hawaii, Order Instituting a Proceeding to Investigate Distributed Energy Resource Policies, Order No., 32269, Docket No., 2014-0194, August 21, 2014, available at http://dms.puc.hawaii.gov/dms/DocketDetails?docket_id=84+3+ICM4+LSDB9+PC_Docket59+26+A1001001A14H14A84843E4191418+A14H14A84843E419141+14+1873&docket_page=4

[12] Public Utility Commission of Hawaii, Regarding Integrated Resource Planning, Docket No. 2012-0036, "Decision and Order No. 32052," filed on April 28, 2014, Exhibit A, "Commission's Inclinations on the Future of Hawaii's

Massachusetts

Massachusetts has launched two proceedings related to power sector transformation. The first of these proceedings centers on planning and investment objectives for grid modernization. The second focuses on rate design.[13] The commission issued orders in these proceedings in 2014 and is in an implementation phase.

Michigan

The Michigan process involves a wide group of business leaders and energy advocates involved in a dialogue on the future of the state's energy policy.[14] The effort to date has been divided into three phases, with the implementation phase (Phase III) scheduled to begin in late 2015. It is still too early in this process to identify the areas on which Michigan intends to focus, but in general state regulators recognize that DER presents both opportunities and challenges that will have to be addressed.[15] A recently issued background report covers five topics: (i) codes of conduct for utilities, (ii) performance regulation, (iii) rate design, (iv) decoupling, and (v) infrastructure planning.[16]

Minnesota

Minnesota has engaged around the issues of DER through a stakeholder process led by the Great Plains Institute (GPI) called the e21 Initiative (short for 21st Century Energy System). The first product of this effort was a report that centers on issues of aligning the business model of the utility and the sector with the desired outcomes for DER. The effort focuses on two sets of issues: the limited options available to customers and the misalignment of utility regulatory incentives through traditional regulation that ties profits to sales.[17]

Among the recommendations of the Minnesota plan is the creation of an integrated resource analysis framework to replace integrated resource plans (IRPs). The concept here is to create an accessible

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Electric Utilities; Aligning the Utility Business Model with Customer Interests and Public Policy Goals." Available at http://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

[13] Massachusetts Department of Public Utilities, Grid Modernization Home Page, viewed 8/19/15 available at http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/grid-mod/grid-modernization.html

[14] Roadmap to Implementing Michigan's New Energy Policy, Project Overview, available at http://www.michiganbusiness.org/cm/Files/Energy_Office/Project-Overview.pdf

[15] Public Sector Consultants, Roadmap to Implementing Michigan's New Energy Policy - Baseline Report, May 2015 available at https://www.nextenergy.org/wp-content/uploads/2015/08/MEO-DOE-Baseline-Research-Report.pdf

[16] RAP, Roadmap to Implementing Michigan's New Energy Policy, Paths to the Future Report, August 2015 available at www.raponline.org

[17] Great Plains Institute, e21 Initiative: Phase I Initiative, December 2014 available at http://www.betterenergy.org/sites/www.betterenergy.org/files/e21_Initiative_Phase_I_Report_2014.pdf

planning process that provides timely and useful information to multiple parties that could use or participate in a more dynamic framework for meeting sector objectives at least cost.[18]

The Minnesota commission has opened a process on grid modernization and has not yet acted on other e21 recommendations.

Rhode Island

System Integration Rhode Island (SIRI) is a small collaborative designed to find ways to improve existing processes in order to capture the value of distributed resources. Like the Minnesota process, the SIRI initiative is an ad hoc stakeholder process whose recommendations will require the attention by regulators to become effective.

District of Columbia

The Public Service Commission of the District of Columbia issued and order opened an investigation into modernization of the energy delivery system for increased sustainability. The Commission states that "opens this proceeding to identify technologies and policies that can modernize our energy delivery system for increased sustainability and will make our system more reliable, efficient, cost-effective and interactive." [19] The Commission process is still in the early stages with initial comments due in August 2015, and the first workshop in September of 2015 that is intended to discuss future plans for the investigation.

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[18] GPI, at

[19] Public Service Commission of the District of Columbia, June 12, 2015, Order Opening Investigation, Formal Case No. 1130, In the Matter of the Investigation into Modernization of the Energy Delivery System for Increased Sustainability, available at https://www.energymarketers.com/Documents/orderno_17912_FC1130.pdf

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Appendix B: Guidance for Integrated Resource Plans and 202(f) Determination Requests

The first portion of this appendix serves to provide a general set of guidelines that should be helpful in development of utility Integrated Resource Plans ("IRPs"). The second portion briefly discusses the process the Public Service Department ("Department") uses under 30 V.S.A. §202(f) in determining whether a proposal is consistent with the Vermont Electric Plan.

The 2016 Comprehensive Energy Plan (2016 CEP) incorporates the Electric Plan. Where the Electric Plan is referenced in statute, the relevant document is the 2016 CEP[1].

Especially relevant to electric utility IRP planning and consistency determinations under 30 V.S.A. §202(f) are Chapters 9, 10, and 11 which directly address electric power. Chapters 12 and 13 outline the state's approach to particular energy resource types (e.g. solar, wind, natural gas, etc.). Natural Gas utilities should see the natural gas section of Chapter 13 for information about the Department's approach to natural gas.

Although those chapters are most relevant, the entire 2016 CEP is the Electric Plan. IRPs and other utility actions that must be consistent with the electric plan should be consistent with 2016 CEP more broadly.

[1] The *2016 Comprehensive Energy Plan* is available on the Department's website at https://outside.vermont.gov/sov/webservices/Shared%20Documents/2016CEP_Final.pdf

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Part A: Integrated Resource Planning Guidelines

Introduction

Pursuant to 30 V.S.A. §218c[2], each regulated electric or gas company is required to prepare and implement a least cost integrated plan (also called an integrated resource plan, or IRP) for provision of energy services to its Vermont customers. The Vermont Electric Plan and Public Service Board ("PSB" or "Board") Orders, beginning with Docket 5270, define requirements that a distribution utility's complete IRP should meet in order to pass the Department's review and comply with the Board's approval requirements.[3]

The IRP process and the implementation of each Vermont utility's approved plan are intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. (30 V.S.A. §218c). The cost and benefit factors to be considered include both direct monetary costs and benefits, and indirect impacts such as environmental and other societal effects.

This addendum establishes guidelines for the development of integrated resource plans; however the ultimate content and organization of an electric distribution utility's plan will be unique to each

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[2] 30 V.S.A. §218c. Least cost integrated planning

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be assessed with due regard to:

(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;

(B) the state's progress in meeting its greenhouse gas reduction goals;

(C) the value of the financial risks associated with greenhouse gas emissions from various power sources; and

(D) consistency with section 8001 (renewable energy goals) of this title.

(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. At least every third year on a schedule directed by the public service board, each such company shall submit a proposed plan to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section and is reasonably consistent with achieving the goals and targets of subsection 8005(d) (2017 SPEED goal; total renewables targets) of this title.

[3] Natural gas utilities (of which there is only one in Vermont at this time) are also subject to §218c, but not to §202 which establishes the Electric Plan.

individual utility. The IRP process is intended, in part, to facilitate information exchange among utilities, regulatory agencies, and the public.

Utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP. Where issues or considerations listed in this document are not germane to the utility, the Department and the utility should, in advance of the utility filing, discuss whether those issues should be included. Also, IRP planning should be conducted with other planning exercises, such as the construction work plan or RUS requirements, in mind. Where a forecast or analysis would serve the purpose of meeting multiple planning obligations, utilities should not be obligated to perform multiple analyses. IRPs will reflect the wide range of planning capacity at Vermont's utilities.

Utilities should use the IRP process to develop methods they will use to evaluate competing investment and purchase decisions to meet customer demand. The range of options available to utilities to balance supply and demand are expanding as new generation, load control, storage, and smart grid technologies become available and affordable. The characteristics of supply and demand resources are changing as well. Historically load was viewed as a fixed obligation which utilities planned to meet with dispatchable supply. Higher penetration of intermittent generation and controllable loads mean that utilities must begin to plan for a future in which both demand and supply have some controllable and some uncontrollable aspects. Grid operators must prepare for more complex grid choreography to balance supply and demand.

Act 56 of 2015 created a Renewable Energy Standard (RES) for electric utilities that requires renewable energy totaling 55% of retail electric sales in 2017, with that requirement growing 4% every three years to 75% in 2032 (Tier 1). Of these renewable resources, some (1% of retail sales in 2017 growing to 10% in 2032) are required to be new, small, distributed generators connected to Vermont's distribution grid (Tier 2). The Act also requires utilities to assist their customers in reducing fossil fuel consumption (Tier 3). Implementation of Tier 3 may result in some electrification of transportation and heating which will impact both overall demand and the daily load profiles of various customer classes. The RES will have significant effects on how utilities plan to balance supply and demand within their portfolios.

In this context, utilities should use the IRP process to demonstrate the underlying methodology and a set of specific tools they will use to evaluate options for balancing supply and demand at the lowest present value life cycle cost as they arise. Because the operating environment is rapidly evolving, using the IRP process as an opportunity to develop, test, and demonstrate these methodologies will allow utilities to react with a greater degree of flexibility as economic and technological conditions in the industry change.

The 2016 edition of this document reflects several important changes to the IRP process:

- An emphasis on using methods for load forecasting and evaluating supply options which can effectively account for uncertainty in emerging technologies.

- The addition of an optional financial analysis which anticipates changes to a utility's cost of service under different scenarios.

- Guidance about how utilities should consider higher penetration of distributed energy resources and increased electrification.

- Discussion of the implications of the RES for load forecasting and supply planning.

These guidelines are intended to highlight areas of importance to the Public Service Department and facilitate further discussion between stakeholders. Where this addendum suggests "consideration" of a topic, the topic may be addressed in the written IRP, discussed with the Department prior to submission of the IRP, or both.

Filing and Approval Process

Filing Schedule and Review

Utilities are required to complete a new at least every 3 years, on a schedule directed by the PSB. The document should reference applicable background reports, analyses, and supporting materials, and the utility should hold these for public and Department review. The utility should file an IRP with the Board that is complete and in accordance with the guidelines contained in 2016 CEP, including this appendix, and Board Orders.

Utilities in Vermont vary widely in geographic size, sales, and staffing levels. Utilities should produce IRPs which reflect the complexity and size of their operations.

Department Review

During the three years prior to the utility filing its IRP with the Board, the utility and the Department should meet periodically and work together with the goal of the utility filing an IRP that is supported by the Department. In addition to reviewing whether the IRP meets requirements described in state statute, Board Orders, and the Vermont Electric Plan, the Department will review the methodologies used by the utility in undertaking least cost integrated planning and make recommendations as to the soundness of those methodologies. The Department's recommendation of approval or non-approval of the IRP is independent of the particular conclusions of the plan, and contingent only on the efficacy of the employed methodology and consistency with statutes, Board orders, and the Vermont Electric Plan. Open communication and interaction between the Department and the utility early in the IRP process should allow the Department to evaluate and support a range planning methodologies.

The Department's review will encompass multiple areas of expertise. The Department's Engineering Division will meet with the utility's engineers to discuss the portions of the plan related to transmission and distribution infrastructure, while load forecasts or power portfolio analysis are the subject of discussions with the Department's Planning and Energy Resources Division. Cost of service and financial implications will bring in the Finance and Economics Division. Timely review and potential support of the IRP depends on effective and engaged communication from both the utility and the Department during these parallel conversations.

Public Service Board Review and Approval

Each regulated electric company shall submit a proposed plan to the Department and the Public Service Board. PSB review will include notice and opportunity for hearing, and based on the evidence of record, a determination as to whether a utility's IRP is consistent with 30 V.S.A. §218c, Docket 5270, and other relevant PSB Orders. The Board may approve the IRP, approve it in part and reject it in part (with or without conditions), or fully reject it. Robust proposals that have included engagement with the Department will improve the likelihood of approval.

Distribution of the IRP

Utilities should file copies of the IRP and any revisions or updates with the Board and the Department; electronically and three hard copies with Department, and such filing with the Board as it may require. Electronic copies should be made available to the Department, the PSB, and the public. Hard copies of the IRP should be made available upon request (at a price not to exceed publication and mailing costs) to parties that intervene in the IRP proceeding and interested citizens of Vermont. The most current IRP should be available on the utility's website.

Required Elements

A robust IRP should contain the following elements:

1. **Executive Summary** suitable for distribution to the public, with an overview of the major components of the IRP.

   The executive summary should also include a description of the utility's current business and system including information such as the number of customers, peak load, which towns the utility serves, the number of substations and circuit miles, current sources of power etc.

2. **Table of Contents** which gives titles and page numbers for sections as well as sub-sections.

3. **Forecasts and Scenarios** which includes load forecasts and alternative scenarios.

4. **Assessment of Resources** which reviews the existing resource mix, identifies a broad range of supply-side options, models the integration of new resources, and leads to the selection of a preferred portfolio.

5. **Financial Assessment** which presents the utility's business plan for the future while providing information on changes in its overall cost of service and electric rates.

6. **Assessment of the Transmission and Distribution System** which evaluates options for improving system efficiency and reliability and presents plans for bulk transmission, grid modernization, and vegetation management.

7. **Assessment of Environmental Impact** which quantifies, assigns a value to, and then considers any significant environmental attributes of the resource portfolio.

8. **Integrated Analysis and Plan of Action** that looks across demand, supply, finances, and transmission and distribution, to identify a least-cost portfolio and a preferred plan of action.

1. Forecasts and Scenarios

IRP analysis begins with a load forecast along with the development of several alternative scenarios. Load forecasting is a long-standing practice of estimating a utility's load based on a range of economic, technological, and weather data. Scenario planning on the other hand considers dynamic or surprising futures that can result from rapidly changing circumstances such as economic downturns, large-scale deployment of new technologies, or changes in customer behavior.

Both forecasting and scenario planning help utilities develop tools to evaluate how they should react to changes in the electric power sector on an ongoing basis in a world where many factors influencing supply and demand are complex and uncertain.

The Department recognizes that utility load forecasts continue to evolve due to many factors including changes in overall economic growth, differential growth across ratepayer groups, volatility in power supply fuel costs, and policy actions. Methodologies used to produce forecasts also continue to evolve as more tools are developed and data become available. Given that historical relationships between these assumptions have changed and are likely to keep changing, the following long-term forecasting guidelines are provided.

1.1. Demand Forecasting

A clear and complete description of the forecast methodology and assumptions should be provided, along with a discussion of the methods and sources used to derive assumptions. If separate models are developed and used for short-term and long-term forecasting, the utility is responsible for providing adequate support for both, along with a clear explanation of methods used by the utility in combining the forecasts.

a. Base Case Forecast

The utility is expected to provide long term forecasts for energy and seasonal (winter and/or summer, as appropriate) peaks, accounting for extreme weather possibilities, to ensure that adequate resources are available to meet customer needs.

b. Weather and Probability

The IRP should include a description for the methodology chosen to incorporate weather into the peak demand forecast. The effects of weather events are a significant factor in developing forecasts of peak demand load. For example, the utility may use historical weather data to create predictions of "average" and "extreme" weather conditions or the utility may develop or use an industry standard 90/10 forecast (a forecast with a 90 percent probability that the actual peak demand will be at or lower than the forecast).

c. Economic Assumptions

Most IRPs will use a commercially available macroeconomic forecast to 'drive' the utility forecast, or at a minimum provide forecasts of key drivers in the model. In doing so, the utility should:

1) Consider referencing one or more alternative forecasts to solicit a range of future outcomes. Alternative forecasts could be averaged to generate a baseline forecast or the spread between forecasts might form the basis for a range in possible economic outcomes;

2) Consider coordinating long term forecasts and planning scenarios by using a baseline forecast that references forecasts by ISO-NE, VELCO, the Vermont System Planning Committee (VSPC) and/or uses similar methodology;

3) Consider the relationship between statewide macroeconomic forecasts and economic activity in the utility's service territory. In other words, consider whether there are significant differences in economic structure and performance in the service territory, such as clear and present seasonal differences from the statewide forecast. If so, the utility should develop proxies for 'local' economic conditions prior to estimating the load forecast;

4) Incorporate into its forecast model economic and structural variables. These variables may include electricity prices, prices and availability of fuel substitution, measures of ability to pay, demographic changes, economic output, or government policy actions;

5) Clearly identify key indicators that drive electric load; and

6) Clearly document the vintage of any macroeconomic forecast used.

d. Policy, Codes & Standards

State and federal policy has a significant impact on electric load. State and Federal building codes and appliance standards affect the amount of overall electricity consumption in the state, both annually and during peak demand periods. Where appropriate, forecast adjustments should be made to incorporate the predicted energy effects of building code updates occurring on a three year basis. Federal appliance and lighting efficiency standards have been established, have known effective dates, and are subject to continual revision. The utility is encouraged to consider, and incorporate where appropriate, the effects of these standards on both energy consumption and available efficiency savings. The codes and standards assumptions and resulting forecast adjustments should be clear and well defined.

e. Renewable Energy Standard (RES) Compliance for Tiers 2 and 3

The Renewable Energy Standard (RES) requires that utilities acquire supply from distributed resources and engage in energy transformation projects to reduce their customers' use of fossil fuels. As of this writing, the Public Service Board has not issued a ruling specifying how utilities should implement the RES; however, the RES makes clear that under Tier 2 utilities are required to obtain significant supply resources from distributed generation. Some of these resources will be "behind the meter" projects that impact net load on an annual, seasonal, and daily basis. For example wide-scale deployment of behind the meter solar both reduces net demand and shifts summer peaks to later in the day.

Under Tier 3 utilities will be aiding customers to reduce their fossil fuel use through a variety of "transformation" projects. These projects may include some efficiency measures that could affect electricity usage as well as fossil fuel usage and they may include measures designed to shift energy use in transportation and heating from liquid and gas fossil fuels to electric-based technology. The addition of these new technologies may drive load upward and shift consumption to different times of day or different seasons. For example, wide-scale adoption of electric heat pumps may increase winter demand for electricity.

When forecasting load, utilities should explicitly consider how their plans for Tier 2 and 3 compliance may impact load from the perspective of total annual sales, and also seasonal and daily use patterns.

f. Demand-Side Management Forecast

Since 2000, energy efficiency services in Vermont have been delivered for most utilities by Efficiency Vermont (EVT), a third party program administrator. EVT forecasts its "statewide" energy and summer peak demand savings with Public Service Board approved planning budgets.

For utilities that deliver their own electric efficiency services, but have specific Board approved planning budgets and savings forecasts, the utility should incorporate those forecasts into the base case and provide a discuss how it expects forecasted energy efficiency savings to affect load.

In both cases, utilities should consider:

1) If and how forecasted efficiency savings will materialize in the utility's customer territory; and

2) How much efficiency investment is embedded in the utility's historical data, affecting its base load forecast.

Utilities may also consider inclusion of alternate scenarios of energy efficiency that depart from the Public Service Board approved 20-year planning budgets.

Independent of efficiency forecasts, the utility should forecast, to the extent applicable:

1) Demand response resources forecasted to be available;

2) Demand impacts of other load management strategies such as rate design; and

3) Energy and power supplied by net metered generators.

4) Where applicable, the forecast should also include projected impacts on load due to or enabled by the adoption of advanced metering infrastructure or other grid modernization technologies.

The utility should consider inclusion of low and high case forecasts for these resources on its system.

g. Emerging Technologies

The utility should explicitly describe its consideration of the expected impact of emerging technologies on its demand forecast, as well as planning for supply and T&D. The utility should also describe its expectations for the adoption of any other new technologies that may increase energy and power needs.

The 2016 Comprehensive Energy Plan explicitly aims to increase electrification in transportation and heating. The RES also creates a Tier 3 obligations will directly impact not only the total amount of energy utilities must provide, but may alter the load shapes of many customer classes. Utilities should consider:

1) Distributed, net-metered generation;
2) Plug-in electric vehicles;
3) Heat pumps;
4) Energy storage; and
5) Other fuel switching technology.

h. Updating the Forecast

Economic and load forecasts should be updated on a regular basis and as significant changes in the environment occur (e.g., economic conditions or government policies that may significantly affect future demand, such as standards or taxes). Utilities should also revise forecasting methods that demonstrate poor performance.

1.2. Alternative Scenarios

In some previous IRPs, scenarios have been developed by adjusting the base-case demand forecast both upward and downward, but without the consideration of disruptive exogenous forces or the possibility of the utility controlling or shaping load itself. Emerging technologies in the electricity sector have the potential to fundamentally reshape how electric power is generated, delivered, consumed, and paid for within the 20-year planning horizon of the IRP. Utilities should use the IRP process as an opportunity to consider not only how load will incrementally grow or shrink, but to evaluate whether and how new technologies and socio-economic forces that are uncertain and outside of the utility's control will impact it and its customers, as well as how new kinds of utility interventions could influence when customers use electricity and how much they use.

Utilities are encouraged to choose a methodology which has sufficient flexibility to evaluate these potentially disruptive and transformative trends for both load forecasting and evaluating supply options. The specific issues the utility considers, and the methodologies it employs to do so are left up to the utility. However, that methodology must be capable of fully addressing uncertainties in electrification, distributed generation, storage, controllable loads and other emerging technologies that may radically change load, supply, and financial solvency of the utility.

One potential method utilities could employ is scenario planning.[4] Scenarios are not predictions of what will happen, but plausible futures that may happen. Utilities can use scenario planning to consider how some of these possible futures may play out and develop tools that will help them react to changing circumstances as they evolve, and actively shape the conditions they will face. Each utility faces a different set of concerns, so scenarios developed by that utility should reflect its unique characteristics.

As utilities consider possible alternative futures, the Department is interested in knowing not necessarily how exactly the utility might respond, but what tools and methods it will use to decide how to respond. These tools will likely include modeling as well as decision-making processes, customer/member engagement, and new innovative programs.

a. Sources of Uncertainty

There are many sources of uncertainty for utilities across the 20-year planning horizon. Some are related to emerging technologies and others are related to exogenous economic forces, weather, or demographics, etc. Methods developed by utilities should include ways to evaluate sources of uncertainty. Scenario planning is one such method, but not the only one.

Because the Comprehensive Energy Plan and the RES call for increased distributed energy resources as well as significant electrification in transportation and heating, utilities should use their IRPs to consider how these state-level policies will impact load and supply, as well as the utility's own role in shaping and managing load. Therefore, methods chosen by the utility to forecast load and compare supply options should be capable of considering the best course of action for the utility under a "high DER (distributed energy resources) and electrification scenario." Utilities should consider the rapid development of high levels of behind the meter generation, storage, and controllable loads as well as significant electrification in the transportation and building heat sectors. Distributed energy resources and electrification will impact both supply and demand.

Methods developed by the utility should also consider areas of particular relevance to that utility. The list below is provided to stimulate thinking about possible futures which differ significantly from base case scenarios.

1) The cost of energy, capacity, and RNS charges at the regional level is either significantly greater or significantly less than current levels.

2) Small-scale solar generation continues to rapidly deploy, constituting an accelerating percentage of the utility's supply; or changes in various incentives cause a slow-down in solar development.

3) The value proposition for electric storage, at either the utility scale or for end-users, improves significantly, for example such that it and can be used to more

[4] For a description of scenario planning in the context of electric utilities, see NARUC's Scenario Planning in a Utility Regulatory Context. Available at http://www.naruc.org/Publications/FINAL%20Full%20Colorado%20SERCAT.pdf.

closely coordinate intermittent supply with demand; or electric storage for end-users remains out of reach.

4) Customers can significantly reduce their net load to the grid by procuring their own generation and storage and they do so in increasing numbers; or customers continue to purchase the vast majority of their needs from the grid, but play a larger role in supply, load control, and/or storage. Note that this could vary significantly by rate class.

5) Electric load grows significantly as transportation and heating are electrified; or penetration of electric cars and heat pumps remains low.

6) Socio-economic forces cause a dramatic increase or decrease in load because of either economic boom or bust.

7) There is an increase in dramatic weather events which cause many more outages and require greater emergency response from the utility.

b. Impacts to Utility Operations

After the utility has identified relevant future scenarios, it should develop methods to consider how it will balance supply and demand, while maintaining or enhancing power quality and reliability. Unlike incremental changes to load, disruptive circumstances will impact the timing and scale of system peak and total energy usage. For example, increased solar production is shifting net peak demand later in the day and may require resources or infrastructure to be planned for later in the day.

Depending on how these sources of uncertainty play out, the least-cost path to balancing demand and supply while ensuring safety, reliability, and power quality will create impacts and require the utility to acquire a different portfolio of resources (broadly defined). To balance supply and demand, utilities should consider both traditional centralized supply solutions as well as distributed energy resources. Utilities should take an integrated look, considering not only the cost of the resource, but the impact of that resource on the grid including any necessary or avoided upgrades.

The IRP should present strategies to address the impact of future scenarios on the following aspects of utility operations:

1) Seasonal load profiles for different types of rate classes;

2) Power supply portfolios on summer and winter peaking days;

3) Timing and magnitude of system peak;

4) Transmission and distribution system upgrades;

5) Recovery of sunk costs;

6) Rates;

7) Total load and supply;

8) RES compliance.

c. Ongoing Application

The utility should develop methods to consider the various possible futures they develop which can be deployed between IRP cycles to evaluate demand, supply, business model, and infrastructure options as they are evolving. These tools might include cost of service models, decision trees for selecting least cost options, methods for considering attributes such as resilience or microgrids, and geo-targeting of efficiency or other DER measures. These methods and tools should be deployed when utilities make major decisions about power supply, load control, and system upgrades.

1.3. Data, Models, and Information

a. Data and Models

In developing forecasts and scenarios, utility should utilize relevant historical data. To aid in review, numerical data should be made available in electronic formats usable by the Department and Board.

The development of forecasts for the 20-year planning period should include consideration of the following information:

1) Customer counts, by class;

2) Total sales of electricity by customer class (annual or by season, as appropriate);

3) Peak load (annual or by season, as appropriate); and

4) Annual sales and coincident system peak contribution for each major customer class.

The IRP or its technical appendices should also document:

1) Source and vintage of independent economic models employed:

2) Description of the forecast model including the relevant variables, coefficients, and the form of the final model;

3) All historic values used in estimating model coefficients;

4) Summary statistics and diagnostics performed on the final model;

5) Characterization of the process used in the development of the final model including variables considered and rejected;

6) Description, including sources, for assumptions including end use detail where applicable;

7) Reason(s) for including any qualitative (dummy) variables, composite variables, and trend variables used in the model; and

8) Historic and forecast values for independent drivers of the forecast, fully documenting the basis for projecting them.

2. Assessment of Resources

The assessment of resources provides an inventory of existing resources and presents supply options along with relevant information about the characteristics of that supply. Throughout the resources section of the IRP, utilities should integrate their plans to meet RES obligations under Tiers 1, 2, and 3.

2.1. Existing Resources

A complete assessment of the utility's existing resources should include an evaluation of the following:

1) Existing and committed base case generating capacity and firm power transactions currently under contract;

2) Potential changes to existing resource commitments, including, but not limited to, re-powering, fuel switching, and life extension of power plants or power contracts;

3) Loss reduction in transmission and distribution systems, and improvements in generation and/or T&D areas;

4) Existing renewable resources;

5) Utility construction and jointly developed projects;

6) Power and REC purchases, including:

    - Purchases through the Standard Offer program;
    - Purchases to satisfy utility RES obligations under Tiers 1 and 2;
    - Purchases from independent power producers;
    - Purchases from other utilities;
    - Customer owned generating capacity;
    - Resources developed through pooling, wheeling, coordination arrangements, or through other mechanisms; and
    - Any other Board approved bid solicitation programs.

2.2. Supply Options Inventory

In describing supply options to consider over the planning period, the utility should identify options in some or all of the following classes:

1) Existing utility owned resources that will serve as future resources should be described, including potential costs.

2) New supply resources that a utility has considered should be discussed, including construction cost, construction schedule, and expected in-service date.

3) Power pooling, power agreements and inter-utility coordination.

4) Opportunities to purchase energy and/or capacity from other utilities or entities should be identified, including a description of the resource potential and costs.

5) Planned purchases necessary to meet reserve margin requirements, and planned energy hedge trades which provide price certainty and reduce exposure to volatility.

6) Existing non-utility generation in the utility's service territory, including customers with generation capability for self-generation, peak shaving, or emergency back-up, which may reduce the need for new capacity.

7) New non-utility owned generating facilities or technologies available, along with options likely to be available during the planning period. It may be appropriate to consider generic examples of particular technologies, rather than specific potential facilities. The utility should also describe the potential for such facilities by technology and fuel type, the likely amounts of capacity and energy available from such facilities at various prices, ownership, the environmental impacts of such facilities, and the availability of such capacity and energy during the 20-year planning period.

8) Interruptible service offerings to improve system capacity utilization.

9) Off-system sales contracts when the utility has excess capacity. When a utility has excess capacity, analysis should be provided in the IRP concerning how it intends to increase efficiency and pursue least-cost service through management of off-system sales.

2.3. Assessment of Alternative Resources

For potential generating facilities and technologies identified as credible options for meeting load during the planning period, the utility should provide the specific information in items 1-10 below.

For consideration of a generic resource and technology (e.g. solar PV, utility-scale wind, natural gas combined cycle, or market purchases) rather than consideration of a particular facility, generic assessments of these characteristics may be appropriate.

1) Description of supply resource – Where available, list the name and location of each station, unit number, type of unit, installation year, heat rate, rated capacity and net capability, capacity factors, net (dependable) summer and winter capability, and installed environmental protection measures.

2) Availability of resource – Delineate the planned and unplanned outage rates and capacity factors of the units or technologies assessed in the IRP.

3) Operating costs – Describe the costs to acquire, operate, and maintain the technology (in addition to fuel costs). The utility should identify historic, fixed, and variable costs for producing energy for the past five years, and projected fixed and variable costs of producing energy over the planning horizon.

4) Maintenance requirements - A comprehensive maintenance program is important in providing reliable, low-cost service. The utility should identify expected remaining useful life, maintenance requirements and outages for base load, intermediate and peaking units.

5) Fuel supply – The utility should specify and describe fuel types, fuel procurement policies, and potential for fuel switching/substitution.

6) Fuel supply reliability – The utility should describe its contingency plan regarding potential supply disruptions, and strategy to meet the goal of having a reliable supply of low cost fuel.

7) Fuel prices – Describe historical fuel prices for the past five years and projected fuel prices over the planning horizon (the fuel forecast should be consistent with the range of load forecasts). The price forecast methodology should be clearly stated and defined.

8) Condition assessment – For resources owned and/or maintained by the utility, describe the utility's plan to maintain and operate supply resources, where economically feasible, at their current levels of efficiency and reliability.

9) RES compliance – Whether the resource satisfies Tier 1, Tier 2, or Tier 3 requirements.

10) Economic risks associated with environmental costs – Where applicable, the utility should identify the quantities of air pollutants, liquid wastes, and solid wastes that are produced by any generation option per unit of electricity produced. In addition, the utility should identify the environmental risks affecting existing and alternative supply resources.

2.4. Smart Rates

IRPs should discuss whether current rate designs for each major customer class are consistent with other components of the IRP, and consider how potential future changes in rate design could facilitate IRP goals. Load control programs should be compared for cost-effectiveness with alternative resources.

The 2016 Comprehensive Energy Plan requires utilities with AMI infrastructure to develop a plan to move to smart rates as the standard option. Smart rates could include time-of-use rates, critical peak pricing, dynamic peak pricing, peak-time rebates, and real-time pricing. The IRP should include such plans for smart rate deployment and estimate the impact smart rates may have on total demand, peak demand, and infrastructure requirements.

A utility's choice of one of these pricing structures for its customer classes could have significant impacts on the demand for both capacity and energy, the relationship between components in a power supply portfolio, and the necessary transmission and distribution infrastructure to deliver the required energy to customers. An IRP should address how the utility plans to incorporate new dynamic pricing structures or rate designs or qualify for the exception outlined in the 2016 CEP (p. 226). The IRP should discuss the expected or projected impact of these planned or potential rate structures on load, power portfolios, and infrastructure requirements, or describe plans to characterize these impacts.

3. Financial Assessment

The financial assessment, new to this edition of the IRP guidelines, is optional for IRPs completed under this guidance document, although utilities are strongly encouraged to submit a financial assessment as part of their IRPs. The Department anticipates making the financial assessment mandatory for the next planning cycle after reviewing the optional submissions.

Should utilities choose to complete a financial assessment, it should present a strategic direction for business. It should consider the impact of the utility's preferred action plan (see Section 6) on revenue, expenses, income, and financing. The financial assessment should describe the utility's expected cash flow and describe its financing plan for any capital expenditures. It should also present the expected financial results of the utility's business plan while providing information on changes in its overall cost of service and electricity pricing.

Relatively simple 5-year financial projections can be made by applying an inflation rate to known, current business expenses and adding in the cost of any known new capital expansions.

3.1. Cost of Service

A utility has an obligation to its ratepayers to manage risk and minimize its system cost. Utilities should evaluate and balance the expected costs, business risks, and long-run public policy goals in developing and selecting a business model portfolio with the best cost-risk combination.

Resource portfolio analysis provides input to the cost of service model that determines the impact on customer rates of each portfolio. The cost of service model includes the impacts of lost sales in the rate calculations for each portfolio. This allows for the assessment of rate impacts of the resource portfolios.

A utility's cost of service model would recognize a utility's financial objectives while meeting energy resource needs through a balanced, lowest cost portfolio, with supply, demand, and energy efficiency options.

Included in the financial section of a utility's IRP filing should be its expected revenue requirement and cost of service for the next 5 years that could include but would not be limited to:

1) Production;
2) Transmission;
3) Distribution;
4) Customer accounts;
5) Sales;
6) Administration & general;
7) Depreciation;
8) Taxes other than income taxes;
9) Other interest expense;
10) Income taxes;
11) Cost to finance rate base;
12) Total cost of service;
13) Expected rate revenues;
14) Rate base;
15) Financing plans including cash flows and planned capital expenditures.

Information on the utility's financial metrics and ratios over the IRP planning horizon should also be provided. The financial ratios could include but would not be limited to:

1) Interest coverage ratio (operating income plus depreciation, divided by interest expense);
2) Debt service ratio (operating income plus depreciation, divided by interest expense plus principal payments);
3) Equity to debt ratio (total equity divided by the total debt outstanding);
4) Return on equity and weighted average cost of capital;
5) Credit rating of the firm; and
6) Each of its outstanding debt instruments.

4. Assessment of the Transmission and Distribution System

Each electric utility should plan and conduct a comprehensive study evaluating options for improving transmission and distribution (T&D) system efficiency and reliability. Based on the findings of that study, it should then implement a program to bring its T&D system to the level of electrical efficiency that is optimal on a present value of life cycle cost basis within a reasonable period of time. These studies and action plans should be reviewed and updated at reasonable intervals. Finally, each utility should implement a program, as part of its IRP, to maintain T&D efficiency improvements on an ongoing basis.

4.1. T&D System Evaluation

Each utility should evaluate individual T&D circuits to identify the optimum economic and engineering configuration for each circuit, while meeting appropriate reliability and safety criteria. The IRP should contain a detailed description of how and when the utility will carry out these evaluations.

Decisions regarding some facilities may affect more than one utility. In such instances, utilities should work together so that their evaluations reflect not only their individual interests, but also the interests of ratepayers generally.

The standard for establishing optimum T&D system configurations and for selecting transmission and distribution equipment is the net present value of life cycle cost. This life cycle cost should be evaluated on both a societal and utility/ratepayer basis. This standard requires consideration of a project's capital costs and life cycle operating costs, as well as benefits resulting from the construction of enhanced system configurations and the installation of energy efficient T&D components. These benefits include avoided operation and maintenance costs, and avoided energy and capacity costs.

Avoided energy costs include the direct costs for energy, the costs for energy consumed as line losses, and T&D delivery costs. Avoided capacity costs include fixed costs and capacity charges for power including on peak line losses, fixed costs and capacity charges for T&D, the cost of Capability Responsibility reserve obligations, the deferral of T&D investments. Other benefits of T&D system efficiency include reduced environmental externalities and reduced market prices due to reduced demand for energy and capacity.

Evaluations should identify and compare all technically feasible investments to improve system reliability and efficiency. At a minimum, evaluations should include (and assess the economics and technical feasibility where appropriate) the following measures:

1) The utility’s power factor goal(s), the basis for the goal(s), the current power factor of the system, how the utility measures power factor, and any plans for power factor correction;

2) Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for feeder back-up;

3) Sub-transmission and distribution system protection practices and philosophies;

4) The utility’s planned or existing “smart grid” initiatives such as advanced metering infrastructure, SCADA, or distribution automation (see Section 4.6);

5) Re-conductor lines with lower loss conductors;

6) Replacement of conventional transformers with higher efficiency transformers;

7) The utility's distribution voltage settings (on a 120 V base), and whether the utility employs, or plans to employ, conservation voltage regulation or volt/VAR optimization;

8) Implementation of a distribution transformer load management (DTLM) or similar program (see Section 4.2);

9) A list of the locations of all substations that fall within the 100 and 500 year flood plains, and a plan for protection or relocation of these facilities.

10) A discussion of whether the utility has an underground Damage Prevention Plan (DPP), or plans to develop and implement a DPP, if none exists;

11) The location criteria and extent of the use of animal guards.

12) The location criteria and extent of the use of fault indicators, or the plans to install fault indicators, or a discussion as to why fault indicators are not applicable to the specific system.

13) A pole inspection program, the plans to implement a pole inspection program, or a discussion as to why a pole inspection program is not appropriate to the specific utility.

14) The impact of distributed generation on system stability.

4.2. T&D Equipment Selection and Utilization

Each utility should describe the process(es) used to select all major equipment (not limited to transformers) according to least-cost principles.

Utilities should develop and adopt any necessary procedures to meet the following standards:

1) All transformer selection and purchase decisions fully reflect the value of projected capacity and energy losses over the equipment lifetime with due regard for expected loadings and duty cycles;

2) Inventory of transformers in use and on hand is to be managed to match transformer loss characteristics with customer load factors; and

3) An ongoing system to monitor and adjust transformer loading for optimal economic benefit is in place.

4.3. Implementation of T&D Efficiency Improvements

As individual circuit evaluations are completed, utilities should schedule the implementation of all cost-effective measures within a reasonable period of time. A utility's IRP should note any progress- to-date in the evaluation of circuits, the development of implementation plans for circuits in which evaluations have been completed, and the completion of efficiency measure installations.

4.4. Maintenance of T&D System Efficiency

Transmission and distribution systems are dynamic in nature, i.e., their configurations and capacities change over time to meet the changing needs of customers. Consequently, the implementation of a set of efficiency measures on a given circuit should not mark the end of the attention given to that circuit. Rather, T&D system optimization should be pursued as an ongoing effort.

Utilities should, as part of their planning efforts, set out a program for maintaining optimal T&D efficiency. This program and progress in it should be reported thoroughly in the utility's IRP and describe, through operating procedures, design criteria, equipment replacement standards, etc., the manner in which optimal T&D efficiency will be maintained. All subsequent cost-effectiveness analyses performed under this program should maintain the standard of present value of life cycle costs.

4.5. Other T&D Improvements

In addition to the improvements outlined above, utilities should comply with the following T&D- related improvements, which address several areas important to T&D least cost planning and system reliability.

a. Bulk Transmission

VELCO, as the responsible planner for Vermont's bulk transmission system on behalf of Vermont ratepayers and utilities, should give special consideration not only to the efficiency of its own facilities, but also to the impact its actions may have on the efficiency of sub-transmission and distribution. Where appropriate, VELCO should support and cooperate with others, including the state’s electric distribution utilities, in undertaking regional T&D optimization studies. The societal test coupled with suitable reliability analysis and attention to strategic planning issues should form the basis for planning and technical evaluation. Where additional transmission capacity is determined to be required following consideration of all non-transmission alternatives, the preferred method for increasing transmission capacity should be upgrading existing facilities within existing transmission corridors (unless it can be demonstrated that such a measure would have a substantial adverse impact on the electric system or societal costs). The utility’s IRP should describe the process undertaken to facilitate inter-utility coordination relative to transmission planning. Transmission projects are reviewed by VSPC established pursuant to PSB Docket 7081. Active utility participation and information sharing in the VSPC should increase the state’s ability to meet reliability requirements in a least-cost manner.

b. Sub-Transmission

Sub-transmission planning should take into account broader interests than those of individual utilities. Where appropriate, integrated regional reliability improvements and sub-transmission system optimization should form the basis for the basic planning and technical evaluation criteria. Utilities should cooperate as needed to assure efficient operation and installation of sub-transmission plant while also assuring an acceptable level of reliability, justified by suitable probabilistic analysis. If necessary, joint utility or utility-regulatory processes should be established to coordinate this activity; collaboration under the auspices of the VSPC may facilitate this coordination. The utility’s IRP should describe the actions taken facilitate inter-utility coordination relative to sub-transmission planning.

b. Distribution

The Board is authorized by statute (30 V.S.A. § 249) to designate exclusive service territories for electric utilities in order to reduce or eliminate the existence of duplicate electric facilities. Where duplicate electric facilities exist, the companies responsible should seek to eliminate the duplication to the extent possible.

In the process of building, rebuilding or relocating lines to roadside, electric utilities should coordinate with the appropriate telephone and cable TV companies during the planning and construction phases to ensure that, wherever possible, no permanent duplicate facilities are installed along the same road and that the transfer of existing facilities to new or replaced poles is done in an expeditious manner.

The Department encourages all utilities to use the NJUNS software to track transfer of utilities and dual pole removal. The utility's IRP should describe the efforts undertaken to ensure coordination with relevant telephone and cable companies relative to transmission and distribution planning.

While there can be significant benefits from roadside relocation of distribution lines, this activity can have a significant adverse impact on Vermont's scenic landscape. Therefore, companies proposing extensive roadside relocation programs should work with all interested stakeholders (ANR Department of Forests, Parks and Recreation; Public Service Department; Regional Planning Commissions; local governments; and the Agency of Transportation as appropriate) to address aesthetic concerns, including techniques or approaches that mitigate the impact on aesthetics. Where the relocation would have only a minimal impact on visual resources, little or no mitigation may be required. However, for projects in areas with high-value visual resources more extensive mitigation procedures should be considered including:

1) Relocation to the less sensitive side of the road;

2) Use of alternative construction techniques such as spacer cable, armless construction, and relocation underground;

3) Development of a site specific vegetation management plan; and

4) Alternative routing.

These discussions should also consider other important factors such as cost, reliability, and worker and public safety.

4.6. Grid Modernization

"Grid Modernization" and "Smart Grid" generally refer to a class of technology that is being used to modernize utility electricity delivery systems by implementing measurements of circuit parameters, two-way communications technology, and computer processing. This technology includes "advanced meters" which are digital meters that play a key role in grid modernization by measuring voltage, demand (kW), and energy (kWh) at hourly or sub-hourly intervals, and by enabling two way communications. For example, utilities could use these voltage measurements to optimize the voltage on a distribution circuit, and employ conservation voltage reduction where appropriate. The potential benefits are that a smart grid would enable utilities and their customers to track and manage the flow of energy more effectively (including the cost of electricity at a given time), curb peak demand, lower energy bills, reduce blackouts, and integrate renewable energy sources and storage to the grid (including electric and plug-in hybrid vehicle batteries). The smart grid also has the potential to increase energy efficiency, thereby reducing environmental impacts of energy consumption, and empower consumers to manage their energy choices. Distribution Automation is also a term that includes technologies that enable a utility to remotely monitor and operate its distribution system, which should result in improved reliability and operational efficiencies. The Department encourages utilities to investigate grid modernization technologies and to implement those that are cost effective.

4.7. Vegetation Management Plan

Each utility should describe its current vegetation management plan (including both cyclic ROW trimming and hazard/danger tree removal) or, if they have not already done so, they should evaluate the merits of implementing a systematic vegetation management plan. Some of the information required in this section may be common to several of the smaller utilities, providing a potential opportunity for these utilities to share in the cost of collecting the information for their respective reports. However, each utility should submit its own report because each utility is responsible for ensuring that the vegetation management program in its service territory is undertaken in a least-cost manner.

A utility may find it useful to work with the Department of Forests, Parks and Recreation to improve the utility's line clearing standards, train utility clearing crews, and update its vegetation management plan. Public information and education is an area in which materials developed by one utility could be shared by other utilities, thus reducing costs. It is important for utilities to make their customers aware of the dangers of trimming near utility lines and the importance of planting low-growing species beneath power lines.

In describing its current vegetation management plan, each utility should provide the information specified in the table below. In addition, the utility should provide a detailed explanation of why its current vegetation management program represents the least cost program, including details on the relative composition of tree species present in its service territory, the annual growth rates of these species, and the vegetation management techniques used (including when, where, and how herbicides are used). Each utility should discuss in its IRP the means used to evaluate the effectiveness of the vegetation management program, including monitoring the number of tree related outages as compared to the total number of outages, and analyzing and comparing the cost of proactive vegetation management versus the cost of responding to storms.

	Total Miles	**Miles Needing Trimming**	**Trimming Cycle (years)**
Sub-transmission			
Distribution			

	Y-2	**Y-1**	**Y**	**Y+1**	**Y+2**	**Y+3**
Amount Budgeted						
Amount Spent						
Miles Trimmed						

Note: Y = the last full calendar year.

4.8. Studies and Planning

Each utility should include a description of all engineering and operational studies conducted since its last IRP, and all studies planned for the next three years. The utility should also include a list of all capital projects completed since its last IRP or in progress. Capital projects planned for at least the next three years should be included in the action plan (see Section 6.4).

4.9. Emergency Preparedness and Response

In its IRP, each utility should describe storm/emergency procedures, such as securing contract crews, dispatch center, participating in utility conference calls, and updating vtoutages.com. This should include a discussion regarding how often vtoutages.com is updated, and, if applicable, what could be done to update it more frequently. Also discuss the utility's operating procedure for internal and external public notifications of planned and unplanned outages.

4.10. Reliability

Each utility should provide in its IRP the data for the last five full calendar years for CAIDI and SAIFI as reported pursuant to PSB Rule 4.900 (i.e., without major storms excluded). These data may be presented in either tabular or graphical format. The utility should discuss the trends of these data, and, if applicable, what additional actions may need to be taken.

5. Assessment of Environmental Impact

The IRP should demonstrate an understanding and due consideration of any significant environmental attributes of the resource portfolio, current or planned. These impacts should be quantified where possible. This could include consideration of greenhouse gas emissions, NOx, and SOx, along with any other environmental impact such as waste disposal. The utility should consider any environmental impacts that it deems material to the outcome of its load management and supply portfolio analysis. If it chooses to exclude any particular pollutants or impacts from analysis, should give an explanation as to why it chose to do so. The utility should clearly demonstrate the derivation of the values used to estimate environmental impacts, including emissions rates, lifetime emissions, and the dollar value of emissions or other environmental costs.

The RES internalizes the cost of many of the externalities associated with greenhouse gas emissions; although the requirements of the RES phase in over time and do not fully eliminate greenhouse gas emissions from the utility portfolio. As the RES phases in, the externalized costs of greenhouse gas emissions should be reduced in IRPs to coincide with reductions of greenhouse gas emissions in the portfolio.

30 V.S.A. section 218c requires due regard of the financial risks associated with greenhouse gas emissions, and the value of such risks should be incorporated into least cost planning where possible. The statute requires that:

> "Economic costs shall be assessed with due regard to:
>
> (A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;
> (B) the state's progress in meeting its greenhouse gas reduction goals;
> (C) the value of the financial risks associated with greenhouse gas emissions from various power sources; and
> (D) consistency with section 8001 (renewable energy goals) of this title."

6. Integrated Analysis and Plan of Action

The IRP should integrate its use of existing and planned supply resources, T&D improvements, and demand-side resources into a consistent plan that meets the need for energy and capacity. The plan should minimize total costs relative to benefits, showing all financial, regulatory, and other significant assumptions including how environmental externalities have been considered. Utilities should, to the extent feasible, report the results of their IRPs in at least the following areas:

1) Expected capital and operating costs of the resource plan and its effect on utility revenue requirements;

2) Impact on costs passed to customers;

3) Impact on the environment;

4) Effects on fuel and technology diversity;

5) Increased coordination between T&D planning and power portfolio planning;

6) Impact on reliability of the system;

7) Impact on the utility's financial condition;

8) Impact on the state and local economies, to the extent feasible; and

9) Use of renewable resources and trajectory for achieving statutory and other targets or goals.

6.1. Risk and Uncertainty Analysis

IRP analysis should characterize the principal sources of uncertainty and the associated risks to utilities and their customers. It should go beyond uncertainties in load to consider other factors that may present risks to the utility and its customers such as fuel prices, loss of a major source of supply, and other key forecast drivers and assumptions behind the base case forecast and resource mix. Where analysis reveals unacceptable levels of risk to the utility and its customers with its present portfolio, the utility should characterize avenues for addressing such concerns.

Analyses should be conducted to examine the risks and uncertainties associated with meeting the customers' energy service needs. The IRP should discuss such analyses which are particularly informative to the development of the action plan. Discussion with the Department during the preparation of the IRP may include discussion of risks not included in the final IRP document. Risks and uncertainties to be considered include, but are not limited to:

1) Fuel prices for electricity production and for customer end-uses;

2) Assessment of current economic conditions;

3) Variation in economic factors;

4) In service dates of supply and demand resources;

5) Unit availability;

6) Market penetration rates for, and the cost-effectiveness of, demand-side programs;

7) Inflation in plant construction costs and the cost of capital;

8) Changes in discount rates;

9) Possible federal or state legislation or regulation;

10) New technological developments; and

11) Unit decommissioning or dismantlement costs.

6.2. Identification of Least-cost Portfolio

Utilities should evaluate a variety of portfolio strategies, noting the uncertainty and sensitivity of each. Strategies that deliver the lowest cost under optimal conditions, but are highly sensitive to the operating environment, may not be the most appropriate choice. Strategies that achieve a relatively low cost under a variety of contingencies may be preferable. Utilities should explicitly account for the critical interactions among potential supply options.

The critical requirement in developing a least cost portfolio of resources is to maintain an unbiased evaluation of options to increase supply and modify demand and to fairly balance costs, risks, and societal impacts. Given the uncertainties inherent in this process, there may be a variety of projects available with identifiable costs and benefits that do not differ widely. Benefits and costs should be evaluated using both a societal test and a utility or ratepayer test; other tests or metrics (such as rate impacts or robustness to uncertainty) may also be appropriate to include.

The integration section of a complete and robust IRP includes a thorough discussion of the following:

1) Identification of an optimal portfolio of supply and distributed energy resources, bulk transmission, T&D, and rate design projects, with a summary of the expected annual energy and capacity costs or savings contribution of each selected option over the planning horizon. Significant concerns of managing the optimal portfolio that relate to financing, project timing, line loss and reserve requirements, and organizational factors should be identified along with any critical externalities that influenced inclusion of the option.

2) Discussion of the methodology and assumptions used to derive the optimum portfolio, with discussion of the sensitivity of results to important assumptions.

3) Discussion of reasonably competitive projects not included in the optimum portfolio, including reasons for exclusion, and whether or not projects will be available for consideration if the strategic environment changes.

4) Discussion of contingency plans associated with the higher risk components of the selected portfolio, including events that would alter the portfolio and trigger a utility's decision to either adopt or terminate a measure.

6.3. Preferred Plan

A complete IRP develops a preferred least-cost plan that fully explains, justifies, and documents the manner in which it was developed, including an explanation of how it ensured internal consistency in avoided costs and retail electricity prices. Where the utility's preferred plan does not minimize net societal costs, the IRP should discuss the utility’s reasoning for pursuing the plan selected.

6.4. Implementation or Action Plan

A complete IRP includes effective strategies for implementing the least-cost integrated portfolio identified in the preferred plan. Provisions for research and data collection necessary to improve planning performance (saturation surveys, supply and demand marketing studies, distribution system mapping) can also be included as proposed action items.

A sound and complete implementation plan should include the following:

1) An overview of the preferred least cost portfolio, briefly discussing how it will be administered and updated.

2) For each near-term program project identified in the preferred plan and scheduled for implementation within three years, provide the following:

    - General procedures for implementing, monitoring, and evaluating the project;

    - General work plan for the project; and

    - Identification of important contingencies that may arise as the strategic environment changes and projects evolve, including adjustment to project plans that should be made to minimize adverse impacts.

3) For any program project identified in the preferred plan and scheduled for implementation after three years, provide a list of expected decision points.

6.5. Ongoing Maintenance and Evaluation

After its IRP is approved, a utility is responsible for administering approved projects, evaluating and reporting on progress, and effectively maintaining its IRP.

Part B: Consistency Determination

The Department under 30 V.S.A. §202(f) reviews certain proposed actions by electric utilities to determine the consistency of those actions with the current adopted version of the Vermont Electric Plan, which is the 2016 Comprehensive Energy Plan (2016 CEP). Companies contemplating proposals for actions subject to PSB approval under 30 V.S.A. §108 or §248(b) should also request a determination in writing from the Director of Planning and Energy Resources under 30 V.S.A. §202(f).

In addition to determining consistency with the specific text of the Comprehensive Energy Plan, the Department will look for consistency with statutory state policies, goals, and requirements, including the goals and policies established in 30 V.S.A. sections 202a(1), 202a(2), 218c, 218e, and 8001.

1. Process

a. Notification

Any company making such a proposal should notify the Director at least 60 days in advance of the proposed action and include, at a minimum, the following information:

1) A description of the proposed action;
2) The nature of the arrangements being proposed;
3) The capacity and/or energy and the terms of the arrangements being proposed;
4) An explanation of the objectives the company seeks to accomplish with the proposed action;
5) How it relates to the company's short and long-range power supply plans;
6) How it relates to the 2016 CEP; and,
7) Any other relevant information.

b. Regulatory Response

The Department will advise the company if additional information on the proposed action will be needed. If so, the Department will make appropriate information requests. The Department will issue the resulting determination as quickly as feasible following the receipt of requested information.

The Department wishes to expedite the review and determination process in every way compatible with its responsibility to conduct a thorough review of proposed actions. For that reason, companies are encouraged to initiate discussion of major proposed actions at an early date.

2. Filing Components

Typical information needed for utility power supply projects or purchases includes the following components. Other actions are likely to require different kinds of information.

a. Economic Analysis

Calculation of the societal costs and benefits of a proposed supply action and of the supply and DSM alternatives the utility has considered. The underlying data, including production simulations and DSM program data, should be included. Submitted analysis should also include discussion (and where possible, calculation) of the opportunity cost of the proposed action.

b. Sensitivity Analysis

Since the results of societal test analyses are highly sensitive to key assumptions that may be hard to predict, it is necessary to determine how varying those assumptions may alter the competitiveness of the proposed action. For this reason, the utility should conduct additional studies incorporating variations of those assumptions (utilizing tools such as Monte Carlo or scenario analysis and including correlations among variables where practicable). All assumptions subject to changes that would have a significant impact on the analysis results should be reviewed. The variations to be studied may be developed with the Department in advance of filing.

c. Diversity Calculations

To help gauge the degree of dependence on the proposed project, a utility's analysis should show the percentage of its energy and capacity requirements the proposed action will provide during the project's life, based on production simulation results.

Similar calculations should be shown for the aggregate energy and capacity from the proposal plus all other entitlements of the utility that use similar technology and fuel.

Appendix C: State Agency Energy Plan Statutory Authority (Title 3 V.S.A. § 2291)

Title 3 V.S.A. § 2291 – State Agency Energy Plan

§ 2291. State Agency Energy Plan
(a)(1) When used in this title, "life-cycle costs" shall mean the present value purchase price of an item, plus the replacement cost, plus or minus the salvage value, plus the present value of operation and maintenance costs, plus the energy and environmental externalities' costs or benefits. Where reliable data enables the Department of Buildings and General Services to establish these additional environmental externalities' costs or benefits with respect to a particular purchasing decision or category of purchasing decisions, that is energy related, the Department may recommend the addition or subtraction of an additional price factor. All State agencies shall consider the price factor and environmental considerations set by the Department when examining life-cycle costs for purchasing decisions.
(2) "State facilities," when used in this chapter, shall mean all State-owned or leased buildings, structures, appurtenances, and grounds.
(3) "State fleet," as used in this chapter, shall mean passenger vehicles and light duty trucks for use by State employees in the conduct of official duties, excluding law enforcement vehicles assigned to sworn law enforcement officers, and shall be procured by the Commissioner of Buildings and General Services.
(b) It is the general policy of the State of Vermont:
(1) To ensure, to the greatest extent practicable, that State government can meet its energy needs and reduce greenhouse gas emissions 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.
(2) To identify and evaluate, on an ongoing basis, resources that will meet State government energy service, infrastructure, purchasing and supply, and fleet needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, purchasing preferences, wise use of renewable resources and environmentally sound infrastructure development, energy supply, purchasing practices, and fleet management.
(c) The secretary of administration with the cooperation of the commissioners of public service and of buildings and general services shall develop and oversee the implementation of a state agency energy plan for state government. The plan shall be adopted by June 30, 2005, modified as necessary, and readopted by the secretary on or before January 15, 2010 and each sixth year subsequent to 2010. The plan shall accomplish the following objectives and requirements:
(1) To conserve resources, save energy, and reduce pollution. The plan shall devise strategies to identify to the greatest extent feasible, all opportunities for conservation of resources through environmentally and economically sound infrastructure development, purchasing, and fleet management, and investments in renewable energy and energy efficiency available to the state which are cost effective on a life cycle cost basis.
(2) To consider state policies and operations that affect energy use.
(3) To devise a strategy to implement or acquire all prudent opportunities and investments in as prompt and efficient a manner as possible.

(4) To include appropriate provisions for monitoring resource and energy use and evaluating the impact of measures undertaken.
(5) To identify education, management, and other relevant policy changes that are a part of the implementation strategy.
(6) To devise a strategy to reduce greenhouse gas emissions. The plan shall include steps to encourage more efficient trip planning, to reduce the average fuel consumption of the state fleet, and to encourage alternatives to solo-commuting state employees for commuting and job-related travel.
(7) To provide, where feasible, for the installation of renewable energy systems including solar energy systems, which shall include equipment or building design features, or both, designed to attain the optimal mix of minimizing solar gain in the summer and maximizing solar gain during the winter, as part of the new construction or major renovation of any state building. The cost of implementation and installation will be identified as part of the budget process presented to the general assembly.

Appendix D: State Agency Energy Plan Leading By Example Case Studies

- Department of Fish & Wildlife: Fish Hatchery Energy savings
- BGS, Fleet Management Services: GoGreen State Fleets Initiative
- Department of Buildings & General Services: Waterbury State Office Complex
- Agency of Transportation: Solar Garages
- The Capital Commuters Program

LEADING BY EXAMPLE

How state government is saving energy, lowering costs, and reducing carbon pollution

Vermont's five hatcheries produce more than 2 million healthy fish for release in state waters each year. Hatcheries require significant amounts of electricity, propane and other sources of energy to grow fish. These five facilities have become surprisingly energy efficient, just by replacing older lighting fixtures and heating systems, introducing new energy-smart equipment and adjusting production processes to reduce energy use.

This year alone, energy improvements at the hatcheries will save Vermont $75,000 on fuel bills and reduce emissions by 3,000 metric tons of carbon. Energy upgrades to date could power all of Grand Isle's homes for a year or allow passenger vehicles to circle the Earth 327 times.

Partnerships Make it Possible

Leveraging a variety of partnerships, the hatcheries have been able to make these changes without a large upfront budget. Funding was provided by the Department of Buildings and General Services (BGS) State Energy Management Program, utilizing one of the revolving loan funds that help agencies implement energy efficiency upgrades and use the energy dollar savings to pay back the loan. BGS reinvests the loan payments in other energy projects. The program is available to all agencies.

Additionally, strong relationships with the U.S. Fish and Wildlife Service yielded access to federal partners' experience and assistance. The Vermont Energy Investment Corporations, another key partner, provided expertize on upgrades to hatchery systems, from pumps to lighting.

Early rearing landlocked Atlantic salmon at Ed Weed are raised in a new tank system that recirculates water, saving water use and the propane needed to heat it.

Doing More Work with Less Energy

Ed Weed

- A variable frequency drive installed to reduce pump speed saves more than $2,900 per year.
- Recirculating heated water needed to grow fish during cold months has decreased propane and electricity costs by approximately $60,000 a year.

Bald Hill

- A high efficiency boiler replaced the less efficient oil fire burner, saving $79,000 over the expected life of the project.
- A solar photovoltaic system installed at the hatchery will produce approximately 34,000 kWh annually and generate $160,000 over the 25 year expected lifetime of the panels.

Bennington

- Installed netting over ponds will reduce predation, improve fish survival and increase production by nearly 30 percent with little additional energy use or cost.

Looking Ahead

Vermont's fish hatcheries have shown that even in tight budget times, and with very limited capital money, investments in energy efficiency and renewable power can be successful. Wide ranging energy improvements were made possible by using innovative financing mechanisms, while leveraging existing relationships between partners that understood that environmental and financial benefits can be achieved by working together. The fish culture program will continue to improve the efficiency of its operations and reduce the amount of non-renewable it uses to the greatest extent possible. Here is what we have in store:

Renewable Power - Growing Fish on Sunlight

To raise fish at a hatchery you need a lot of power. Despite their small size and efficiency, Vermont's hatcheries spend nearly $250,000 a year on electricity. Fortunately, by taking advantage of a state contract with the Vermont-based company All Earth Renewables, the Department of Fish and Wildlife will be able to build two new on-site solar projects that will offset all of its hatchery electricity usage and reduce its electricity bills by 10%, without upfront costs.

The partnership will enable the Department to access the company's expertise in permitting and design. The two projects, totaling 650 KW in capacity, will help support progress towards state government's ambitious 2025 and 2050 renewable energy goals.

Saving More Energy

The Fish & Wildlife Department is also planning the next round of efficiency investments.

Ed Weed

- New efficiency intake pumps will save $12,000 a year.
- Reducing the height of the water intake "headbox" will pay for itself in less than a year and save more than $2,000 a year.

Bald Hill

- A new solar thermal panel hot air heating system will circulate air warmed by the sun to supplement the hatchery building's conventional heating system.

Salisbury

- New variable frequency drives will reduce pumping costs by nearly $12,000 a year – and will pay for themselves in less than two years – with no loss of performance.
- New more efficient lighting will save money and electricity.

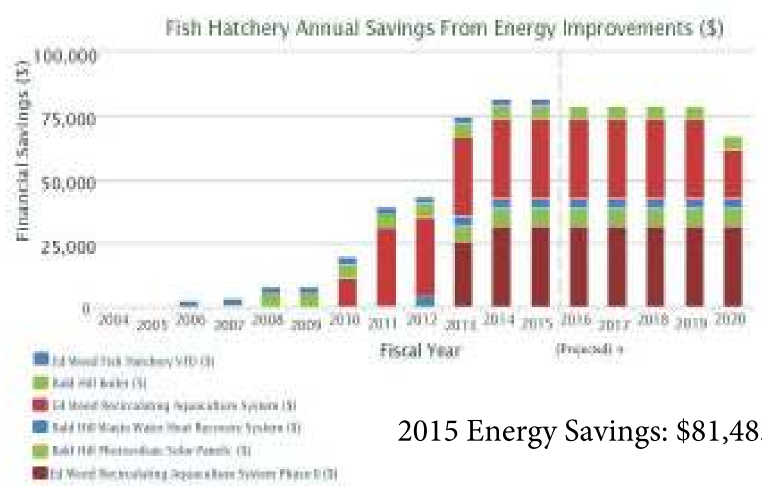
Bennington

- New efficient lighting fixtures will pay for themselves, saving electricity and money.

Roxbury

- Upgrading the current propane boiler to a wood pellet boiler will reduce fossil fuel use, save money, and support the timber industry.

Upgrades to date save enough energy annually to power all of Grand Isle's homes for one year, or to fuel a car traveling around the Earth 327 times.



2015 Energy Savings: $81,483

LEADING BY EXAMPLE

How state government is saving energy, lowering costs, and reducing carbon pollution

Transforming Transportation
The New GoGreen State Fleets Initiative

Almost half of Vermont's greenhouse gas emissions come from transportation –from moving people and goods around our rural state. State government is committed to reducing the fossil fuel use and emissions from its own transportation activities, by:

- Replacing conventional vehicles with cleaner plug-in hybrid and all electric models;
- Adopting new policies and practices to ensure that state employees travel from place to place as efficiently as possible; and
- Reducing our travel miles.

In the next five years, state agencies will work together on a new initiative to significantly reduce the fossil fuel used in state transportation.

Progress on Reducing Greenhouse Gas Emissions

Almost half of state energy use is from vehicle travel – from the use of passenger sedans that transport employees to meetings and site visits, and from the use of many trucks and plows that perform critical maintenance and construction work.

The new State Agency Energy Plan sets ambitious goals for greening state transportation, including displacing 10% of current gasoline use by 2020, 25% in 2025, and one-third by 2032.

Achieving them will be challenging. The path must include converting the state's fleet to electric vehicles – the cleanest cars on the road today. The Department of Buildings and General Services (BGS), the agency that manages approximately half of the State's vehicles, has made great progress in the last several years.

A More Efficient Fleet

- There are now 49 conventional hybrid vehicles and 13 plug-in electric vehicles in the state's BGS fleet, making it the largest electric fleet in Vermont.
- BGS is working with other agencies to ensure that when vehicle replacement occurs, the new vehicles are as fuel efficient as possible. Since electric models are not yet available for trucks, improving average fuel economy of the state's conventional vehicles is critical.
- In the future as more biofuels become available, the state may also be able to displace conventional diesel with these lower emitting alternatives.

There are now 13 plug-in electric vehicles in the state's BGS fleet, making it the largest electric fleet in Vermont.

BGS
BUILDINGS & GENERAL SERVICES
WORKING TOGETHER TO SERVE VERMONT

Charging Infrastructure

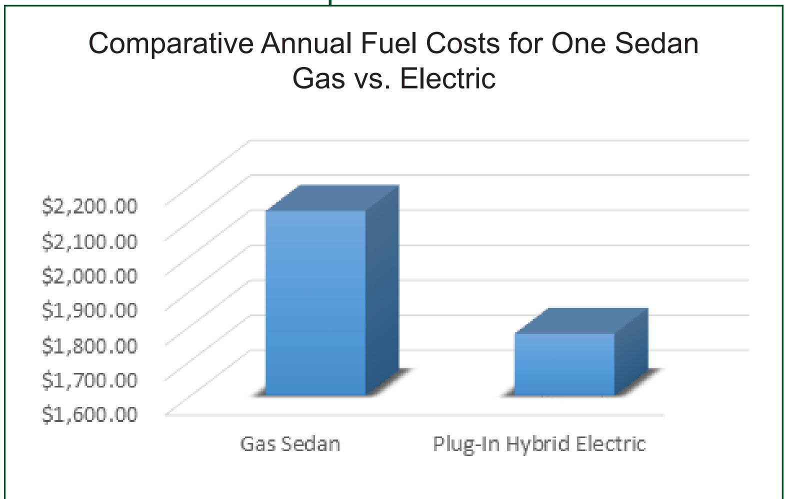
- During construction projects, BGS is pursuing installation of charging stations to power fleet vehicles and enable employees who commute in EVs to charge at their workplaces. Eight "Level 2" chargers with capacity to simultaneously charge 16 vehicles are now available at fleet headquarters. The new Waterbury Office complex includes two dual port Level 2s with electric infrastructure in place to increase the number of chargers when needed.

- BGS has awarded a contract to Green Mountain Power to provide electric vehicle charging infrastructure to all state agencies, local municipalities and public schools. BGS used its standard bid process to ensure new stations will meet high standards and be cost-effective.

Looking Ahead

Although state government has made good progress on electrifying the fleet, the total energy used in state transportation still increased almost 30% since 2012.

Starting in 2016, the state will launch a new **GoGreen State Fleets Initiative** to drive progress towards the transportation energy goals in the State Agency Energy Plan. Led by BGS with participation and support from many other agencies, the initiative will work on reducing fossil fuel use in state transportation to save taxpayer dollars, scale back energy use and reduce harmful greenhouse gas emissions.



By demonstrating the benefits of environmentally friendly, safe transportation for all Vermonters, the initiative will also help support progress on the state's plan to accelerate the adoption of electric vehicles by businesses, institutions and households all across Vermont.

By using a Fleet Electric Vehicle, state employees save taxpayer dollars and reduce harmful greenhouse gas emissions.

What needs to be done?

- **Adding More EVS.** Converting a larger percentage of the fleet to electric vehicles is within reach: a wider selection of affordable cars with electric ranges up to 200 miles are soon coming to market. BGS will add at least five new EVs to the fleet each year. Employees whose trips can be made in EVs will be assigned those vehicles whenever possible.

- **Rightsizing the Fleet.** Maintaining a fleet with high average fuel efficiency – including efficient heavy-duty trucks for which there are no electric models yet– can dramatically reduce fossil fuel use.

- **Educating Employees.** BGS will offer Ride and Drive events and employee training to get the state's work force comfortable with new EV models, and to encourage their use. Education about eco-efficient driving practices that reduce fuel use and air emissions, such as avoiding single driver trips, reducing idling, and slowing average highway speeds, is also a top priority.

BGS
BUILDINGS & GENERAL SERVICES
WORKING TOGETHER TO SERVE VERMONT

LEADING BY EXAMPLE

How state government is saving energy and money– while helping the climate – for all Vermonters

The Waterbury State Office Complex
A Model for Green, Climate Resilient Building

The State Office Complex in Waterbury, Vermont was hit hard by Tropical Storm Irene in 2011. Water levels rose above the first floor of many buildings, and agencies were forced to relocate their employees to temporary locations scattered across the state.

When Vermont's Governor Peter Shumlin decided to rebuild state offices at the site, the Vermont Department of Buildings and General Services (BGS) saw a rare opportunity to design and build a complex that would save state government tens of thousands of dollars annually and model green building for other organizations – with energy and climate smart features throughout.

Description and Financing

The property loss at the Waterbury State Office Complex was extensive. Complicating this challenge was the fact that many of the original buildings were located in floodplain areas at high risk for future flooding. New buildings would have to be highly cost effective to operate, and resilient to the more severe weather events and flooding that scientists are expecting in the northeast due to a changing climate.

The State funded the project with a combination of insurance, federal disaster recovery funds, and state bond revenues. BGS and the Agency of Natural Resources established close partnerships with the Federal Emergency Management Agency, the Town of Waterbury, and local community and business organizations to make the complete redevelopment of the historic complex possible.

The project includes the restoration of the site's "historic core," a collection of 13 historically significant buildings that face Main Street. It also includes a biomass heat plant, restored floodplain, a new energy efficient office building that can be heated and cooled at low cost to the state's budget, green stormwater infrastructure and enhanced pedestrian circulation.

Doing More Work with Less Energy

- **Energy efficient heating and cooling.** The new and retrofitted buildings include efficiency measures that will dramatically reduce the costs of operating office buildings. Integrated "building envelope systems" will protect historic exteriors while air sealing and insulating to reduce unwanted and costly heat transfer. New energy management systems will control HVAC and lighting to maximize occupant comfort and minimize building energy usage, for example by automatically shutting down heating and cooling systems when windows are open.

The Complex is on track to become the State's first LEED Gold Certified Campus, a renowned, internationally recognized green building accreditation.

- **Heat from Vermont-grown wood chips.** The new central heating plant has a highly efficient woodchip-fired boiler with back-up propane. With this new heating system in place, the state will no longer burn the higher greenhouse gas emitting #6 fuel oil for heating state government owned buildings anywhere in Vermont

- **Conservation.** The complex will reduce water consumption with widespread use of low flow fixtures, which save energy too.

Preparing for Future Storms

The site plan integrates flood resilient site locations and designs to minimize the risk of future flood damage and restore a healthy floodplain that helps protect Waterbury's downtown. For example:

- **Moving Away from the River.** 22 buildings totaling 300,000 square feet located closest to the river were demolished, and fill was removed to lower the floodplain and reconnect it to the river. The removed fill was used to elevate the new office building and central heat plant above the 500 year flood elevation.
- **Flood-proofing.** All of the mechanical, electrical and plumbing in the historic building was removed from the basement areas, and the basement areas were filled and structurally reinforced, so that the lowest floor elevation of those historic buildings is also above the 500 year flood level.
- **Greening-up.** Almost 1000' of river frontage was replanted with vegetation to create healthy riparian buffers that can slow floodwaters. Green stormwater infrastructure, such as swales and plantings, were installed to help absorb and clean stormwater from rain events that can pollute the river.

Clean Energy On Site

- **A new solar roof.** The state has entered into a group net-metering agreement with a private solar developer to finance and install a 100 kW rooftop solar photovoltaic system on the new office building. The solar panels will save money and help Vermont achieve it's renewable energy goals with no upfront cost to taxpayers.

- **EV-ready parking.** The state's Fleet motorpool is going electric. The Waterbury State Office Complex will have two dual port charging stations to serve the all-electric and plug-in hybrid fleet vehicles, and capacity to host an additional five stations when demand increases.

Looking Ahead

The new Waterbury State Office Complex, due for full occupation in 2016, marks an exceptional achievement of state government and exemplifies construction practices for the future.

Energy smart investments will reduce the Complex's greenhouse gas emissions by 5,000 metric tons (CO2E) – the emissions from heating and powering over 450 homes.

LEADING BY EXAMPLE

How state government is saving energy, lowering costs, and reducing carbon pollution

Powered by the Sun
VTrans Solar Garages

In 2013, the Vermont Agency of Transportation (VTrans) took the first significant steps towards reducing energy costs and greening operations at the agency's 60 garages, where hundreds of state trucks, plows and construction vehicles are housed and serviced.

VTrans has now installed on-site photovoltaic solar energy systems at six garages, and is planning to install solar net metering projects at a majority of its facilities as funding allows. The transition will help support progress towards Vermont's goal – included in the 2016 Comprehensive Energy Plan – of meeting 90% of the state's energy needs with renewable sources by 2050.

The solar panel array at the Orange garage is 100 feet long and consists of 72 panels ground-mounted on fixed racks.

Description and Financing

VTrans' decision to go solar was helped along by the state's "net metering" law. Net metering allows electric customers, including state agencies and other public and private institutions, to generate power from solar, wind and other renewable sources. In exchange, Vermont utilities credit the customers for the power that their systems produce.

The state garage in the town of Orange was the first to install its own photovoltaic system in 2013. Consisting of 72 panels each roughly 5 ½ by 3 feet in size, the solar array runs 100 feet along ground-mounted fixed racks positioned next to the parking lot at the garage. The annual projected power production of the array is 19,700 kWh – 21,000 kWh, or enough electricity to power three average households in Vermont for one year.

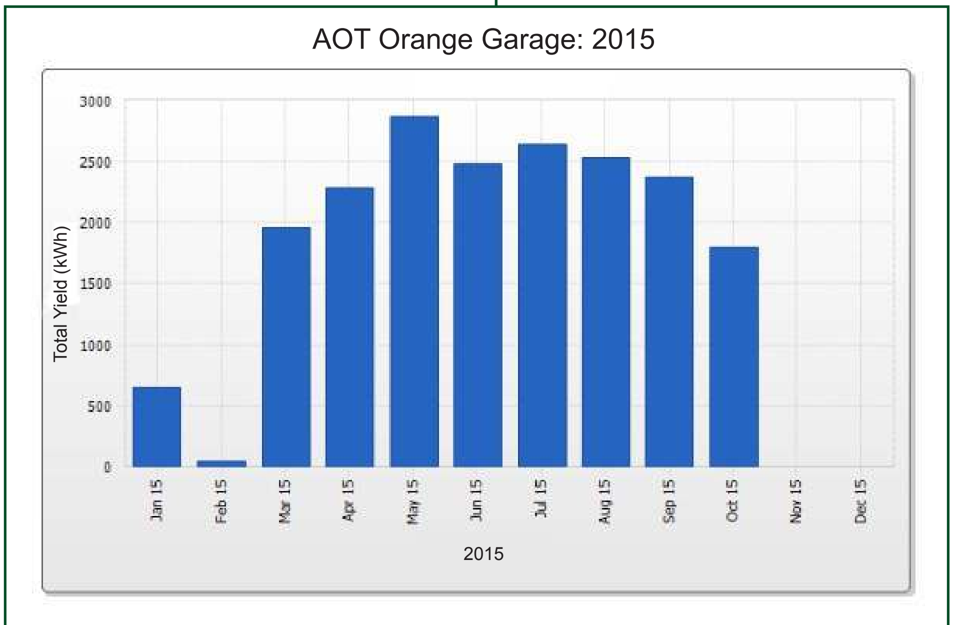
Although the photovoltaic system is relatively small, its installation required careful planning to stay within the agency's budget. The final price tag in Orange came to $52,777, a cost that included all equipment (solar panels, rack systems, inverters, foundation materials and miscellaneous hardware) and the labor of an electrical contractor to connect the photovoltaic system to the grid.

VTrans realized significant savings when the agency trained its own district employees to construct the system on-site. Done when the employees had down time from their regular highway maintenance duties, the in-kind labor resulted in an estimated savings of between $25,000 and $30,000. The installation work prepared staff to manage future maintenance and repairs on the array.

Solar net metering projects such as this one are on the rise in VTrans. To date, the Agency has installed six photovoltaic systems at the Orange, North Montpelier, Bennington, Readsboro, Wilmington, and Dummerston state garages. At an average cost of $61,500, the installations were paid for through the Agency's Transportation Buildings appropriation, which is approved by the legislature each year.

Saving Money Builds Support

These on-site energy initiatives can increase employee morale among staff who take pride in the fact that their efforts are reducing their workplace's reliance on fossil fuels, and the associated greenhouse gas emissions.



They also build staff support as they save VTrans money. At current rates, the power generated by the new solar systems is worth roughly $0.20/ kWh. As an example, over 12 months in 2015, the VTrans garage in Orange generated 19,601 kWh. The project will pay for itself in roughly 12 years and will generate energy valued at over $98,000 during the 25 year expected life of the panels.

Garage employees that helped build the six systems can now watch electric meters spin backward. VTrans has taken care to ensure that each garage gets credited with the cost savings from going solar, so they use the savings to meet other garage budget needs.

Looking Ahead

As budgetary constraints allow, VTrans plans to install three solar net-metering systems per year over the next 10 to 15 years. Each system will be similarly sized and dependent on an average annual budget of $200,000. Construction scheduling will be carefully planned to optimize staff availability during the spring and summer and minimize disruption to highway maintenance efforts.

For more information on the VTrans Maintenance & Operations Bureau's solar net-metering effort, contact Tim French, timothy.french@vermont.gov, 802-224-6593.

VTrans realized significant savings when the agency trained its own district employees to construct the photovoltaic system on-site.

The Orange garage project will pay for itself in roughly 12 years and will generate energy valued at over $98,000 during the 25 year expected life of the panels.

LEADING BY EXAMPLE

How state government is saving energy, lowering costs, and reducing carbon pollution

Green Transportation Choices for State Employees The Capital Commuter Program

The State of Vermont's Capital Commuter program, an innovative alternate transportation initiative, takes to heart the financial, logistical and environmental challenges of commuting in Vermont. Launched by the Agency of Transportation (VTrans) in July of 2013, Capital Commuters incentivizes state employees working in Montpelier to take the bus, carpool, bike, or walk to work, reducing the energy usage and greenhouse gas emissions from single-driver commute trips as well as the need for expansive parking lots at state offices.

Description

After the relocation of hundreds of state employees from the flood-damaged Waterbury State Office Complex to offices in Montpelier, competition for parking spaces was at an all-time high. The construction of hundreds of new spaces was not plausible, affordable or sustainable, so at the direction of the Agency of Administration (AOA), VTrans created a working group tasked with developing alternate transportation models for state employees.

The result was a three-year pilot project designed to benefit enrolled participants and provide a template for green commuting programs for state agencies and private businesses that want to reduce environmental impacts from employee travel and solve parking problems in downtown areas. Over 550 state workers (about 10% of the eligible workforce) have registered so far. Key features of a Capital Commuters membership include:

- **Discounted bus passes**
- **Preferential carpool and vanpool parking**
- **Discount card for use at local businesses**
- **Qualification for Go Vermont's "Guaranteed Ride Home" benefit that reimburses costs (up to $70) for an alternative way home (taxi, bus, rental car) in the event of an emergency**

The Many Benefits of Green Commuting

The Capital Commuter program was developed by VTrans along with representatives from the Agency of Administration, the Department of Buildings and General Services, the Human Resource Department, the Vermont State Employees Association, the Montpelier Energy Committee, and the Green Mountain Transit Agency. Local businesses supporting the program sponsored discounts at their stores. The program has:

Capital Commuters incentivizes state employees working in Montpelier to take the bus, carpool, bike, or walk to work, reducing the energy usage and greenhouse gas emissions.

- **Reduced Parking Needs.** Results from an annual survey of Capital Commuter participants indicated that the program is reducing parking needs between 100-200 spaces per day. The average cost to build a parking space in the U.S. is $15,500[1]. As such, the estimated cost savings of avoided construction of these 100-200 parking spaces is between $1,550,000 and $3,100,000.

- **Reduced Fossil Fuel Use.** By reducing the number of single-driver commutes, the program has saved participants money, lessened our environmental impact and supported progress towards the goals set forth in the Comprehensive Energy Plan. Those benefits have been quantified using participant responses to survey questions about their commuting activities before and during the program, and using the average distance Vermonters commute (23 miles). Because of the program:

    - More than 1 million passenger vehicle miles have not been driven.
    - More than 40,000 gallons of gasoline have not been consumed.
    - More than 780,000 pounds of climate polluting carbon dioxide emissions have been abated.
    - Program participants have saved over $100,000 by buying less gas.

The Capital Commuters working group and the forum it provides paved the way for other great solutions for reducing single occupancy vehicle travel, such as an expansion of CarShare VT to Montpelier and support for bike friendly infrastructure projects.

By reducing the number of single-driver commutes, the program has saved participants money, lessened our environmental impact and supported progress towards the goals of the Comprehensive Energy Plan.

Looking Ahead

VTrans supported start-up work to launch the pilot as part of the state's Go Vermont program, including development of the brand and website, coordination of registration, and distribution of promotional material. State and federal funds covered the roughly $12,000 in start-up costs.

VTrans also covered the $244,900 cost of subsidizing employee bus passes between July 2013 and June 2015. As of July, 2015, state agencies cover the costs of subsidizing discounted bus passes for their own employees, estimated to be between $130,000 and $150,000 in SFY 2017.

The successful three-year pilot ends in June, 2016. The Steering Committee is meeting in March, 2016 to determine if this should be made into a permanent program and/or extended to all State employees. In addition, the state hopes the pilot will provide a model for private businesses, non-profits and other employers wishing to reduce the impact of their employees commutes by providing efficient commuting incentives.

For more information about Capital Commuters, visit:
www.connectingcommuters.org/capital-commuters/ or contact
Ross MacDonald, ross.macdonald@vermont.gov, 802-828-5577.

[1] *Transportation Cost and Benefit Analysis II – Parking Costs*
Victoria Transport Policy Institute (www.vtpi.org)