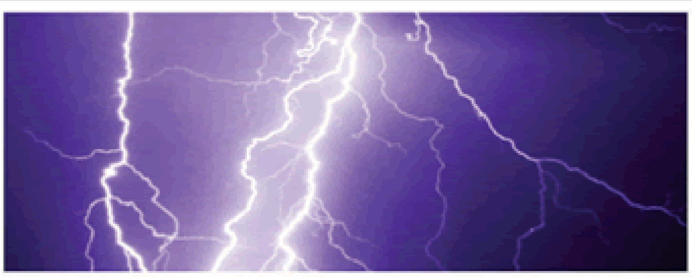
Synapse
Energy Economics, Inc.

Electricity Scenario Analysis

for the

Vermont Comprehensive Energy Plan 2011

REVISED: September 19, 2011



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1. Definition of Scenarios

Synapse was asked to evaluate the costs and benefits associated with alternative energy strategies for Vermont during the plan period, 2012-2031. As detailed below, this modeling task included two parts: *dispatch modeling*, which models the operation of the electric system in Vermont and the rest of New England in order to estimate the cost of electricity and pollutant emissions under each of the scenarios; and *economic impact modeling,* which compares the spending, employment, and gross state product (GSP) effects of the scenarios.

The dispatch modeling is based on a previous dispatch modeling analysis performed by Synapse for the Avoided Energy Supply Cost (AESC) study group and report, completed in 2011. The 2011 AESC Study was sponsored by a group representing all of the major electric and gas utilities in New England as well as efficiency program administrators, energy offices, and utility regulators. For the current study, the Reference Case model was modified to include all existing and expected DSM programs in New England, which had not been included in the AESC study. For Vermont, only DSM investments through 2011 were included in the Reference Case. The updated load forecasts used for Vermont and other New England states are described in Section 2 of this report.

The scenarios modeled were:

1. **Reference Case with no new DSM ("Reference Case")**: This case, intended only as an baseline for illustrating the costs and benefits of the other two scenarios, assumes no further funding of demand-side management (DSM) measures in Vermont after 2011. All other NE states are assumed to continue funding DSM, and the associated energy savings for future programs are set at current or proposed levels. Renewable resources are included in Vermont and New England sufficient to meet the existing minimum renewable portfolio standard (RPS) and other requirements in all New England states.
2. **Proposed DSM Case:** Similar to the Reference Case, except that DSM is implemented in Vermont throughout the plan period (2012 – 2031) following the current DPS proposed budget. The annual incremental energy use and peak load reductions associated with these programs are as forecasted by GDS Associates for this level of spending. The ongoing impacts of DSM spending in 2011 and in prior years are also included. Investments in new renewables are decreased relative to the Reference Case due to the smaller amount required to meet minimum RPS requirements with decreased energy use in Vermont.
3. **High Renewables and Hydro ("High Renewable Case"):** Includes all DSM in the Proposed DSM case, and includes new renewable energy resources to reach the goal of meeting 75% of Vermont's energy use with renewables and hydropower. In contrast to the RPS requirements in the Base and Proposed DSM Cases, existing biomass and hydropower all count towards the 75% renewables goal.

All three scenarios include continued operation of all existing renewable energy and VEPPI resources in Vermont.

The scenarios are summarized in Exhibit 1.

Exhibit 1: Comparison of Energy Future Scenarios. Quantities of generating capacity are reported in Megawatts (MW)

Case:	Reference Case (baseline for evaluating other scenarios)	Proposed DSM Case	High Renewable Case
VT DSM	No new spending after 2011.	Annual spending following DPS proposed budget; savings as estimated by GDS Associates.	As in Proposed DSM Case
VT RPS	RPS target of 25% new renewables on an energy basis by 2025 (ramping smoothly from current & expected) then no growth. Includes FIT new net-metered resources.	As in Reference Case, except reduced to reflect lower load.	75% hydro plus renewables on an energy basis, including Reference Case renewables, existing hydro & HQ.
VT Biomass	Existing resources continue at current levels; 60 MW new biomass by 2013.	As in Reference Case, except that output of McNeil increased due to installation of catalytic converter.	As in Proposed DSM Case; all biomass counts towards 75% goal. Cost premium added to reflect policy.
VT Hydropower	Existing resources (including VEPPI resources) continue at current levels. 6 MW added under FIT in 2013.	As in Reference Case	Expansion of HQ imports to 24 hours; 40 MW of additional hydro contracted to state. Cost premium for all hydro to reflect policy.
VT Feed-in Tariff	50 MW by 2013, no more thereafter; all distributed solar Included in RPS.	As in Reference Case	50 MW by 2013, growing at 5 MW/year thereafter for 10 years. Assume not needed after 2023.
*VT Non-Electric Fuels**	No new spending after 2011.	Consistent with current programs as modeled for the EE impact study.	As in Proposed DSM Case
Surrounding states	Current policies on EE, renewables.	As in Reference Case	As in Reference Case

** Non-electric fuel policies/scenarios were considered in the economic modeling, but do not affect dispatch modeling.*

2. Electricity Scenario Modeling

A. Dispatch Modeling

For each of the three "Vermont energy future" scenarios, Synapse estimated the impact on electric energy market prices using the Market Analytics model, licensed from Ventyx, an ABB Company. The results of this analysis are provided later in this report.

Market Analytics is a production-cost model that simulates the operation of the wholesale electric energy market. The National Electric Reliability Council's (NERC) dataset for the Eastern Interconnection was used in this analysis, with various model inputs revised to more closely reflect up-to-date electricity market conditions, with particular attention to Vermont. These input modifications draw extensively from those made for the Avoided Energy Supply Costs in New England study and subsequent report ("the AESC study"), released in July 2011.

The modeling assumptions and methodology used for the AESC study are described in detail in the AESC report.[1] Updates and modifications to these assumptions and methodology are described below.

Load Forecasts and Projections of Demand-Side Management (DSM) Resources

A primary foundation of any dispatch modeling effort is the projection of peak load and annual energy use in the study area, and in specific sub-areas of interest. For the current study, we base our load forecasts on the CELT load forecasts published by the New England ISO.[2] These forecasts are provided with and without "Passive Demand Resources" (PDR), which is the ISO's term for the combined impact of energy efficiency and distributed generation resources. In order to forecast load for this analysis, we used the (higher) forecast *without* PDR, and then adjusted the forecast to accommodate energy efficiency and distributed generation resources. For all New England states other than Vermont, state or utility energy efficiency program planning reports were used to project future annual incremental energy savings and summer peak load reductions. Because these reports generally do not extend through 2031, for the purposes of this study we assumed the energy savings impacts projected for the last year in the planning reports are repeated annually through 2031.

For Vermont, we use the same CELT forecast for the Reference Case (without "PDR") but adjust this forecast to reflect Vermont DSM investments in 2011 and all prior years. This results in a decreasing DSM impact through the study period as the impact of those investments decays over time, with an average measure life of 11 years. For the Proposed DSM case, we apply the level of energy efficiency program funding for Vermont (the "3% savings scenario") recommended by Vermont DPS beginning in 2012 and continuing throughout the study period. We apply annual incremental energy savings as projected by GDS Associates for this level of spending. These funding and savings data were provided to Synapse by the DPS. In later years, higher levels of incentives are required to induce more customers to participate in efficiency programs; thus each

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[1] Hornby, et al., *Avoided Energy Supply costs in New England: 2011 Report*. Prepared for the Avoided Energy Supply Component (AESC) Study Group. July 21, 2011. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf

[2] http://www.iso-ne.com/trans/celt/report/index.html

constant dollar of utility spending achieves lower savings than it does in the earlier years. Cumulative savings were estimated using an annual constant decay factor based on an 11-year measure life.

The annual savings in Vermont under each scenario is shown in Exhibit 2; for comparison, the total savings in 2031 as a percentage of pre-DSM energy requirements is shown for each of the New England states, under each scenario, in Exhibit 3. The resulting annual energy requirements for Vermont under each scenario are shown in Exhibit 4.

Exhibit 2: Annual energy savings in Vermont under the Reference Case and Proposed DSM scenarios.

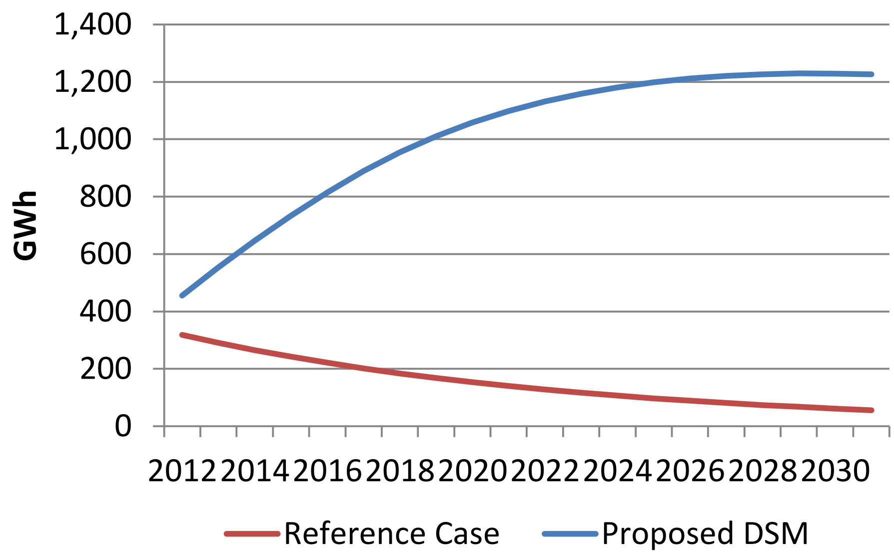


Exhibit 3: 2031 Energy savings in New England states under the Reference Case and Proposed DSM scenarios, as a percent of pre-DSM requirements.

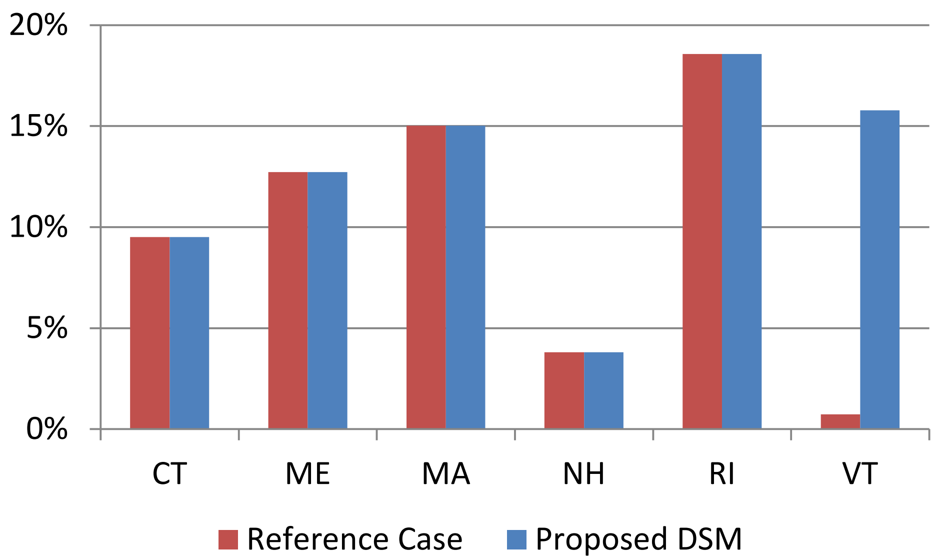
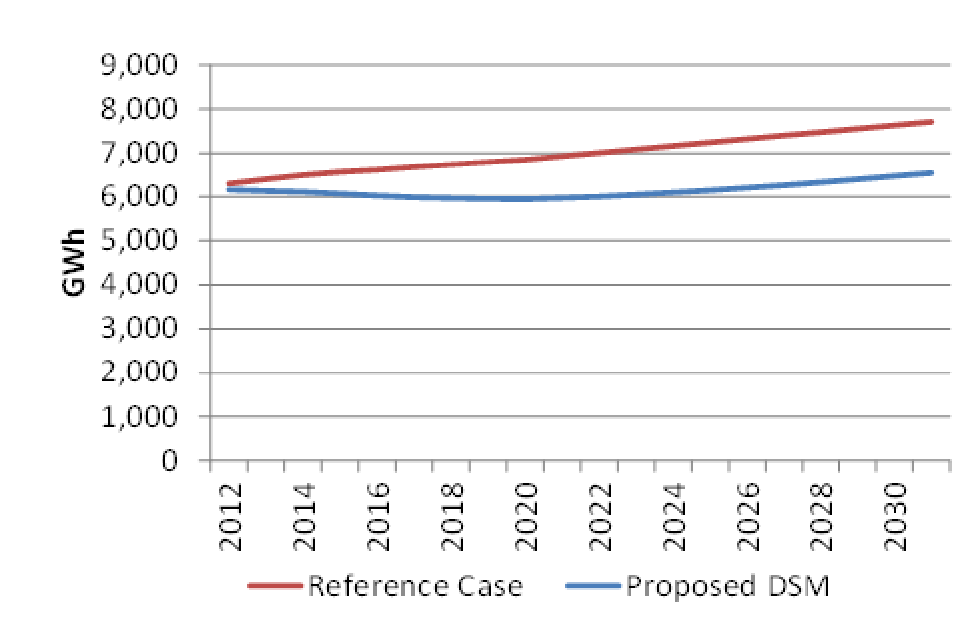


Exhibit 4: Annual energy requirement in Vermont under the Reference Case and Proposed DSM scenarios.



Other Dispatch Model Assumptions

Other assumptions required for modeling the electricity market and costs for consumers in Vermont include fuel price forecasts, emissions prices (including the future cost of greenhouse gas emissions) transmission interface limits, and resources additions and retirements during the study period. The assumptions used in this study for fuel and emissions prices follow those used for the 2011 AESC study, and are described in detail in the AESC report. Fuel prices were extended to cover the current study period using the compound annual growth rate for the last five years of the AESC study (2021 – 2026). For pricing CO_2 emissions from the electric sector, the floor price from the Regional Greenhouse Gas Initiative (RGGI) was used as the emissions price for carbon dioxide. A federal greenhouse gas regulation program was assumed to supersede the RGGI program beginning in 2018. For this analysis, Synapse' projections of CO_2 emissions prices were used for the period 2018 through 2031.[3]

The transmission system used in this analysis reflects the interface limits of the existing system, as well as ongoing transmission upgrades, including but not limited to those contained in the ISO-New England ("ISO-NE") Regional System Plan. Specifics of the transmission upgrades are detailed in section 2.3.2.3 of the 2011 AESC report.

Resource Additions and Retirements

The modeling analysis assumes that the majority of plants in operation today will continue operating throughout the study period. Assumed existing plant or unit retirements were driven by one of the following factors: 1) inability to comply with future environmental regulations; 2) equipment failure in older, less cost-effective units; 3) the expiration of operating licenses for nuclear and hydro units that are unable to meet the requirements for license extension, including the Vermont Yankee nuclear plant; and 4) space constraints that arise when new generation capacity is constructed at the site of existing capacity and forces the existing capacity to retire. Projected unit retirements during the study period are shown in Exhibit 5.

[3] Johnston, et al. *2011Carbon Dioxide Price Forecast*. February 11, 2011. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf

Exhibit 5: New England generating unit retirements as represented in the dispatch model (all scenarios)

Station Name	Unit Type	Summer Capacity (MW)	Retirement Date	State
Somerset	Stream Turbine	108.5	10/1/2010	MA
Somerset	Gas Turbine	21.8	10/1/2010	MA
St Albans	Gas Turbine	2.2	10/1/2010	VT
Vermont Yankee	Nuclear	604.3	3/21/2012	VT
Salem Harbor	Stream Turbine	83.9	1/1/2013	MA
Salem Harbor	Stream Turbine	80.5	1/1/2013	MA
Bridgeport	Stream Turbine	130.5	1/1/2013	CT
Holyoke Cabot	Stream Turbine	19.3	1/1/2013	MA
Norwalk Harbor	Stream Turbine	162.0	1/1/2015	CT
Norwalk Harbor	Stream Turbine	168.0	1/1/2015	CT
Salem Harbor	Stream Turbine	149.9	1/1/2016	MA
Salem Harbor	Stream Turbine	436.5	1/1/2016	MA
Montville	Stream Turbine	407.4	1/1/2016	CT
Middletown	Stream Turbine	400.0	1/1/2016	CT
Cleary	Stream Turbine	26.0	1/1/2016	MA
Wyman	Stream Turbine	52.0	1/1/2018	ME
Wyman	Stream Turbine	51.0	1/1/2018	ME
Mt. Tom	Stream Turbine	143.4	1/1/2020	MA

New generating resources are added to the modeled electricity market over the course of the study period in order to satisfy requirements for renewable generation under Renewable Portfolio Standards, to meet increasing demand due to future load growth, and to meet capacity gaps that may result from unit retirements. Market Analytics is not a capacity expansion model, and does not add new units when the need arises; therefore, any new units must be added to the model directly.

Renewable Additions

Renewable Portfolio Standards typically mandate that a percentage of electricity sales be met by renewable generation. RPS programs are based on tradable Renewable Energy Credits (RECs) that need not be produced within a state in order to qualify for that state's RPS requirement. Thus renewable generation was modeled to equal the total requirement in New England but not necessarily distributed on a state-by-state basis according to RPS requirements. Because RPS programs require renewable energy production as a percentage of total energy sales, implementation of DSM has the effect of *reducing* the requirement for renewable energy in a state. Thus the Projected DSM scenario has a lower renewable energy requirement than the Reference Case scenario in this study.

Vermont does not currently have an RPS requirement, instead supporting renewable resource development through the Sustainably Priced Energy Enterprise Development (SPEED) program, along with the pilot feed-in tariff designed to support the development of certain small-scale renewable projects, and the provision for net-metered distributed solar resources. The feed-in tariff program calls for the development of 50 Megawatts (MW) of renewable generation by 2013, and qualifying resources include solar, wind, biomass, landfill gas, farm methane, and hydro facilities, subject to maximum size requirements. Renewables were added in the Market Analytics model to meet this 50 MW goal, and the allocation among technologies was determined by examining the Vermont projects that have already been installed or have had their applications approved. These projects total approximately 42.5 MW of installed capacity. Because the bulk of new applications for the feed-in tariff program are from solar projects, new distributed solar resources were added to the model to make up the remaining 7.5 MW of installed capacity.

As requested by DPS staff, our analysis assumes that Vermont *does* adopt an RPS requirement starting in 2012, ramping up to a requirement that 25% of energy sold in the state is matched with Renewable Energy Certificates (RECs) in 2025 and for every year thereafter. New net-metered resources, up to the statutory cap of 4% of peak load, are included in the RPS requirement.

Non-Renewable Generic Additions

After adding planned generating units and renewable additions to meet RPS standards, "generic" units may be added to the model to meet any additional capacity requirements or if justified on economic grounds. However, given the low projected load growth during the study period, state DSM programs, and renewable energy requirements, no such additions were found to be justified under any of the scenarios considered.

B. Economic Modeling

Energy efficiency generates economic activity throughout Vermont in the form of purchase and installation of energy efficiency goods and services; administration of the program itself; and net energy savings to ratepayers and participants. Households that participate in the program save on energy costs and can thus spend additional money in the local economy, spurring job growth. Businesses have lower energy costs that improve their bottom-line, enabling them to be more competitive and to expand production and employment. For the current study, these benefits are quantified and tallied through the study period, the years 2012 through 2031. However, the actual benefits in household and business savings—and the economic benefits that derive from them—would extend for many years beyond the study period, even if no additional energy efficiency investments were made.

The investment in efficiency itself generates economic activity as equipment is produced, sold, installed or maintained by Vermont businesses. Renewable energy investments spur economic activity through installation of technologies such as solar photovoltaic panels or wind turbines. As with energy efficiency equipment, the extent to which the equipment is produced locally and local workers build or run the facility determines its economic impact on the state.

Efficiency investments also cost participants money for their part of the efficient equipment and installation costs. As participants spend money on energy efficiency goods and services, their ability to spend elsewhere is reduced. Further, all ratepayers are negatively impacted by the energy efficiency program costs in their energy bills. The additional costs of renewable investments are also factored into energy rates. These negative impacts offset, in part, the positive impacts from energy-efficiency and renewables-related investments and savings.

The REMI PI+ Model

Synapse and the DPS collaborated in the use of the PI+ model (formerly Policy Insight) developed by REMI (Regional Economic Models Inc.) to estimate the economic impacts of Vermont's energy efficiency programs and renewable energy development. This model is used throughout the US, including by many state and federal government agencies. The model has dynamic functionality to capture structural changes in the regional economy that result from economic inputs and costs.

REMI has built-in baseline forecasts of economic activity that are calibrated to each study region--in this case the State of Vermont. Changes to economic activity represent "policy changes" that affect the trajectory of the state economy—in this study, such changes include changes to consumer spending; to businesses' energy costs; and additional commercial activity and industry demand related to energy efficiency investments. The model results (presented in Sections 3 and 4 of this report) illustrate the impact of each scenario in terms of economic activity and employment in Vermont, relative to the Reference Case.

Background on Economic Impacts

The economic impacts of any new activity depend on the extent to which that new activity affects supporting industries in the region. Economic impacts arise from:

1. Direct economic effects (e.g. spending on goods and services at a construction site or the purchase of a piece of new equipment), and
2. Multiplier effects which include:
    a. Spending on supporting goods and services by the firms providing that direct activity ("indirect" impacts), and
    b. Re-spending of wages earned in the state ("induced" impacts).

In general, energy efficiency and renewable investments create net positive local economic impacts. In other words, more jobs are created through these projects than are lost by the activities they displace, such as electric generation or the sale of fuel oil. This net positive impact is due to the fact that more of the dollars spent on energy efficiency and renewable energy remain in the local economy than do dollars spent on "traditional" electric generation or fossil fuel purchases. Energy efficiency is also more labor-intensive than electricity generation or fuel sales, creating more jobs per dollar spent than electric generation, and the economic benefits of energy efficiency investments continue to accrue throughout the life of each energy efficiency measure. The size of that net impact depends on how the region is defined, the amount of energy savings, and how much of the spending by each affected industry remains within the region.

In this report, we estimate the costs, savings and economic benefits resulting from energy efficiency and renewable energy programs and investments in Vermont during the 20-year study period (2012 – 2031). The results of the study represent the *net new economic activity* generated by the investments: the difference between the economic activity increase associated with new investments in Vermont and the economic activity reduction associated with the costs of the efficiency programs. It does not attempt to quantify the ongoing benefits of energy savings beyond the end of the study period.

Basis for Economic Impacts

The economic modeling through REMI takes into consideration all of the changes in cash flow due to the funding and activities of the efficiency programs. Inputs to the REMI model fall into the following categories:

Energy Efficiency:

- *Program and Participant Spending.* Efficiency investments have an economic impact from equipment that is produced within the region and to the extent that local contractors install the equipment. The program also requires spending on administration and overhead to operate.
- *Participant energy savings.* While users have to invest in upgrades or equipment at the outset, savings start to accrue immediately and continue throughout each efficiency measure's life, which can be a decade or more beyond the time of investment. Households take these savings and spend a portion on other goods, further stimulating the local economy. Businesses realize lower energy costs, freeing up capital for investment. Types of savings include energy (electricity, natural gas, heat and process fuels), water, operations and maintenance, and savings due to the deferred replacement of old equipment.
- *Ratepayer Effects.* All ratepayers are affected by the adoption of an energy efficiency program. The program is funded in part through a Systems Benefits Charge (SBC), assessed as a percentage of each electric bill. Counteracting this additional expense is the reduction in energy prices due to decreased demand for energy in Vermont. This is often referred to as the Demand Reduction Induced Price Effect (DRIPE). Other sources of savings include utility avoided infrastructure costs, savings on Vermont's share of Pooled Transmission Facility (PTF) costs, and savings in capacity costs.

Renewable Energy:

- *Construction, Operations and Maintenance.* The installation and operation of renewable facilities generate activity in the state through the use of local materials and labor to install and run the facilities; to the extent that any of the equipment or material is produced in state this provides a further stimulus.
- *Ratepayer Effects.* Energy consumers pay for the cost of renewable facilities, including a return on investment, in their energy bills. Typically, the construction costs are spread over many years and can be represented as a levelized cost of energy. Once installed, renewable energy resources run at low cost, providing downward pressure on regional and local energy prices.

3. Impact of Energy Efficiency Investments

Investments in energy efficiency produce benefits in terms of consumer savings, and also economic benefits to the state in terms of enhanced economic activity and employment. Section

3A details the direct consumer savings, while 3B examines the broader economic benefits deriving from these savings along with the investments that produce them. As noted earlier, only the costs and benefits that accrue during the study period are quantified, although benefits associated with energy savings would continue to accrue for years beyond that.

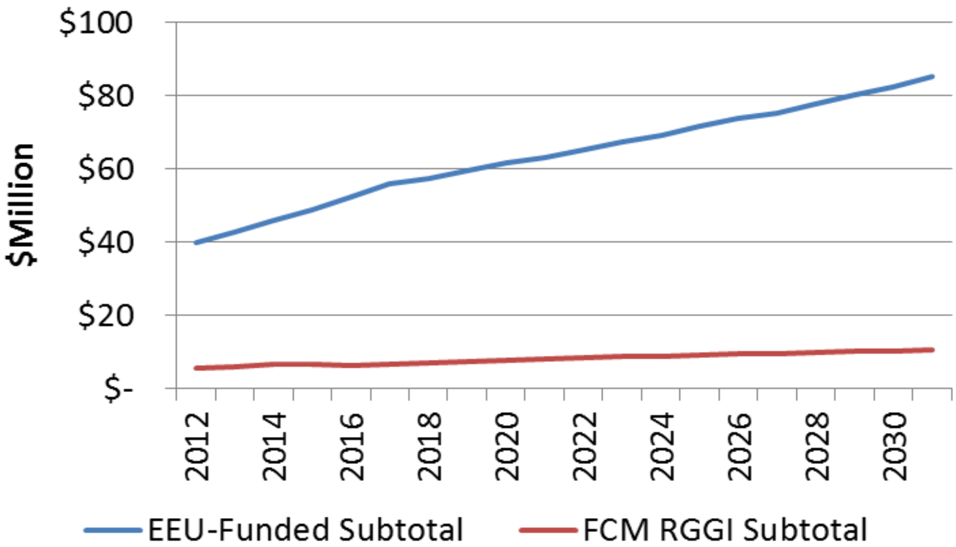
A. Costs and Benefits for Consumers

The analysis of the Proposed DSM Case is based on energy efficiency investments from two sources: funding for the Energy Efficiency Utility (EEU) based on System Benefit Charges on ratepayer bills, and funding from revenues from the New England Forward Capacity Market (FCM) and allowance proceeds from the Regional Greenhouse Gas Initiative (RGGI). For purposes of this study, the EEU revenues are assumed to come from Vermont ratepayers reducing their ability to spend funds on other goods and services. This effect partially offsets the savings associated with energy efficiency investments. The FCM and RGGI revenues are not counted as direct expenditures from Vermont ratepayers; however, RGGI costs are born through somewhat higher electricity rates, and FCM costs are related to utility spending for capacity which is then passed on to ratepayers.

Exhibit 6 shows the annual budget for energy efficiency from each of these sources, as used in the Proposed DSM Case as well as the High Renewable Case.[4]

[4] For the Proposed DSM Case, we modeled the specific measures each year by scaling up Optimal Energy's characterization of Vermont DSM program spending for 2012, described elsewhere in the Comprehensive Energy Plan. However, the program profile changes in 2020 to account for the introduction of the federal lighting standard, which displaces part of the current and near-term state program.

Exhibit 6: DPS-proposed Vermont energy efficiency budget for study period in current-year dollars.



Gross Energy and Energy Cost Savings

Participants in the energy efficiency program save by forgoing the purchase of energy and related expenses. We find that participating residents and businesses in Vermont save $3.74 billion in estimated energy-related spending under the Proposed DSM case over the course of the 20-year study period relative to the Reference Case, in current-year dollars. Exhibit 7 shows the distribution of total savings by type of energy spending. The largest portion of the savings derives from reduced spending on electricity ($2.66 billion, or 71%) while the rest is distributed amongst natural gas, heating fuels, water and operations and maintenance savings.

A small component of energy cost savings is attributable to a reduction in wholesale energy prices as regional demand decreases relative to supply. However, due to its small size relative to the New England electricity market, changes in Vermont load have only a modest impact on regional electricity prices; on average over the study period, prices decrease by 0.5% in the Proposed DSM Case relative to the Reference Case. Thus the primary cost savings benefit of DSM investments in Vermont is directly associated with a decreased quantity of electricity purchased in the state.

Exhibit 7: Cumulative Gross Energy Savings by Type in the Proposed DSM Case relative to the Reference Case (2012-2031, current year dollars.) Values do not include savings that accrue after the end of the study period.

Scenario	Projected DSM Savings ($million)	% of Program Savings
Electricity	$2,657	71%
Avoided Capacity	*$203*	*5%*
Avoided T&D	*$37*	*1%*
Elec. Purchases	*$1,899*	*51%*

Pooled Transmission	*$519*	*14%*
Natural Gas Substitution	-$4	0.1%
Oil, Propane, Kerosene	$250	7%
Operations and Maintenance	$549	15%
Water	$151	4%
Deferred Replacement Credit	$133	4%
Total Gross Savings	**$3,732**	**100%**

Costs to Participants and Ratepayers

Gross savings from DSM are partly offset by ratepayer and participant expenses. Through the System Benefits Charge, ratepayers cover the costs to deliver and administer energy-efficiency programs and financial incentives claimed by participants. Other sources of funding for the program are allowance proceeds from the Regional Greenhouse Gas Initiative (RGGI) and proceeds from sales of demand response resources into the Forward Capacity Market (FCM).

Program participants pay for the portion of energy efficiency investment costs not covered by program incentives. In general, most participants use loans to cover this expense for larger investments; thus these costs are represented as an amortized cost over the estimated lifetime of the investment. The portion amortized and amortization period are shown in Exhibit 8.

Exhibit 8: Assumptions for Participant Financing

Type of Program	% expense of amortized	Years to amortize
New Construction	100%	20
Residential Multi-Family programs	50%	10
Existing Homes/Retrofits	50%	5
Heating Equipment	0%	N/A
Retail Products/Low-income programs	0%	N/A

In the early years of the study period, we assume that program participants pay an average of 52% of the cost of efficiency measures, and ratepayer funds are only required for 48%. For the program to reach greater depth in later years, it is likely that the incentive portion will have to be increased significantly. In this analysis, we assume that by 2031 the incentive will reach 90% of measure costs.

Exhibit 9 shows the total spending of $1.8 billion on program administration, equipment and installation over the course of the plan period. This includes the combined spending from Vermont's energy efficiency program and RGGI and FCM funding for heat and process fuels, as well as participant costs.

Exhibit 9: Total Program and Participant Costs 2012-2031 (million current $)

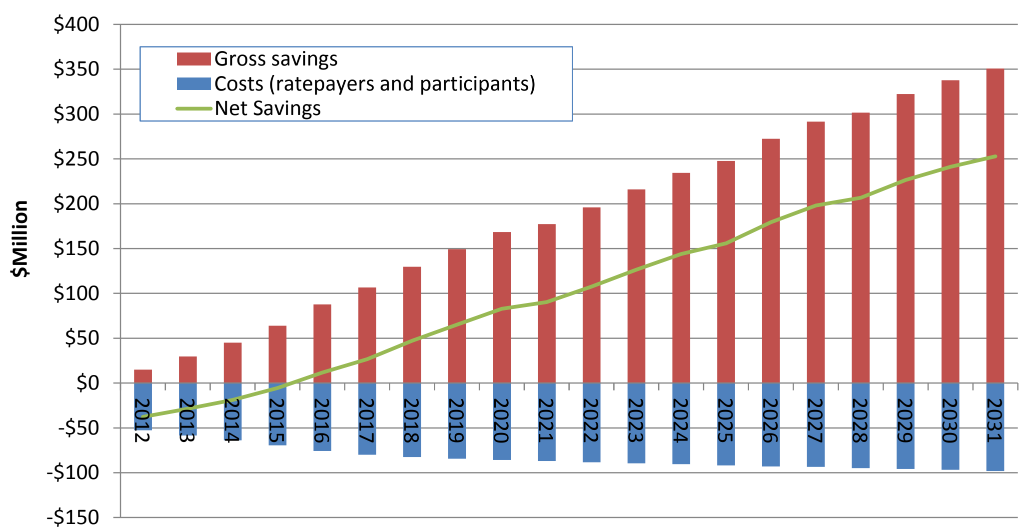
DSM Program Component	Cost
EE Equipment and Installation	$1,126
Participant out-of-pocket costs	*$375*
Incentives	*$751*
Program Delivery/Administration	$690
Total Program and Participant Spending	**$1,816**

Net Savings

The annual program and participant costs and savings, as well as the net savings, are shown in Exhibit 10. The net savings of the program totals nearly $2.1 billion over the 20 year period in current year dollars. As shown below, in the first years the program has a net cost to Vermont. After 2015, the aggregate benefits of the installed efficiency measures cause the program savings to outweigh the costs. These net savings continue to grow as more measures are installed through 2031.

It is important to note that by considering only savings that accrue during the study period, the results significantly *understate* the total net benefits of efficiency spending between 2012 and 2031. This is because new DSM measures are funded in the model through the end of the study period, but the benefits of these measures will continue for a decade or longer beyond the end of the period. Thus, even if Vermont and its citizens were to cease spending on DSM entirely after 2031, considerable energy and financial savings would continue to accrue for a long time thereafter. Because this study only quantifies costs and benefits during the study period, these longer-term benefits have not been included in the current analysis.

Exhibit 10: Gross Savings, Costs and Net Savings Projected DSM Scenario relative to the Reference Case 2012-2031 (current year dollars.) Values do not include savings that accrue after the end of the study period.



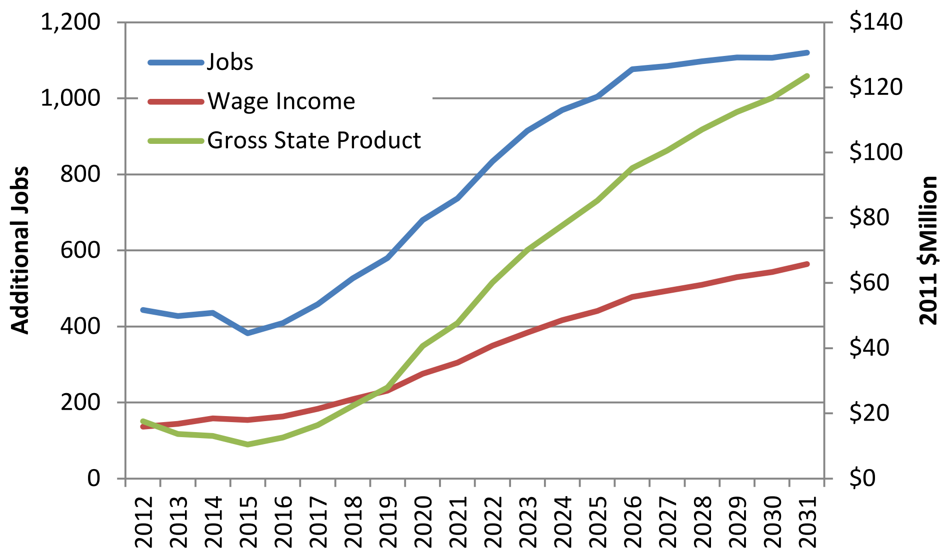
B. Jobs and Economic Benefits for Vermont

Net Economic Impacts

DSM investments and the resulting savings produce value and jobs in the Vermont economy. Under the Proposed DSM Case, we estimate that a total of 15,394 person-years of additional employment will be produced relative to the Reference Case during the study period—an average of 770 additional jobs every year in Vermont. These jobs will generate an additional $778 million in income for Vermonters over the study period in 2011 dollars ($1,098 million in current year dollars), or an average 2011-equivalent salary of over $50,540 per year. Exhibit 11 shows these benefits on an annual basis. Because the wage and GSP benefits are shown in constant dollars, all of the growth shown during the study period may be attributed to the accruing of benefits from an increasing stock of installed DSM measures.

As is the case with energy and cost savings, employment benefits will continue to accrue after the end of the study period. These benefits, which have not been quantified here, derive from the additional spending ability of Vermont households and businesses associated with their lower energy costs after the study period.

Exhibit 11: Additional jobs (left axis) and other economic benefits (right axis, in constant dollars) associated with the Proposed DSM Case relative to the Reference Case, 2012-2031.



The investments and savings under the proposed DSM scenario will also yield $1,704 in gross state product during the study period. In sum, every million dollars spent on energy efficiency (of which $0.89 million comes from ratepayer funds) is projected to produce $0.54 million in gross state product, and $0.86 million in wage income. At the same time, each million dollars spent produces a net savings of $1.84 million for consumers and businesses on electricity costs, and $2.59 million in total savings during the study period. These benefits would continue to accrue after the end of the study period.

The economic benefits on a per-unit basis for the Proposed DSM Case (along with the High Renewable Case) are shown later in this report, in Exhibit 17.

4. Impact of High Renewables Case

For the purposes of this study, we assume that Vermont will institute a state Renewable Portfolio Standard (RPS) goal of obtaining at least 25 percent of the energy purchased in the state from renewable sources by 2025 under all model scenarios.

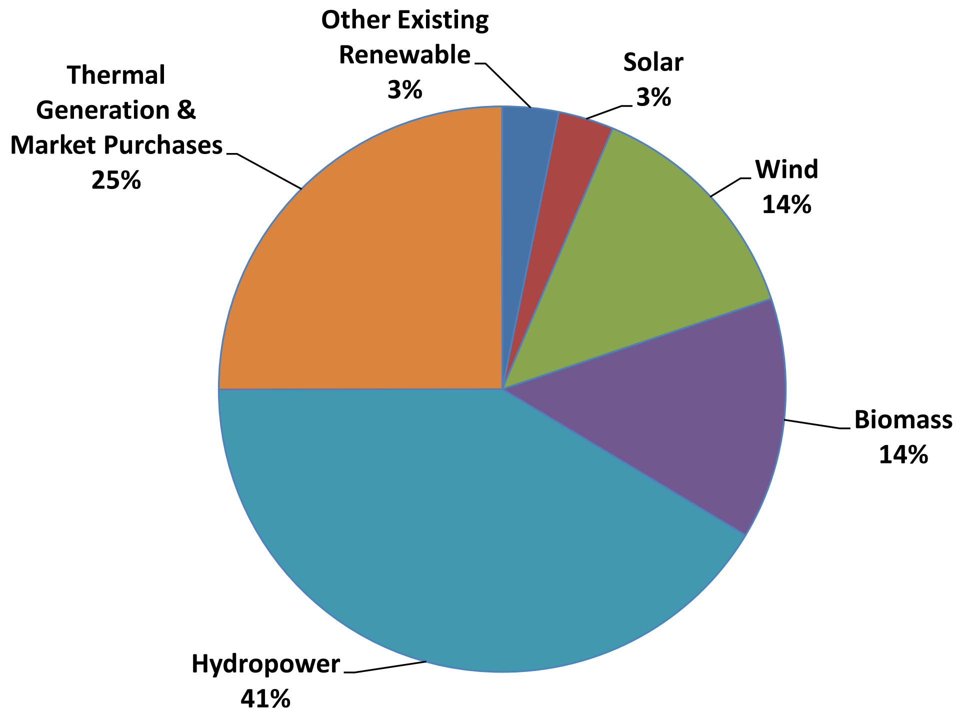
The High Renewable Case expands the renewable energy goal for Vermont from 25% to 75%, while retaining the same level of DSM as the Proposed DSM Case. Unlike for the RPS requirements, existing biomass and hydropower are assumed to count towards the 75% goal.[5] The resource mix for Vermont under this scenario includes the following:

- DSM investments and savings following the current DPS proposal
- Expansion of feed-in tariff from 50 MW to 100 MW, with the additional 50 MW composed of distributed solar phased in from 2015-2025
- Expansion of import contract with Hydro Quebec to cover 24 hours, instead of the current 16-hour-per-day contract reflected in the Reference Case
- 40 MW of additional hydropower contracted to Vermont, with a 35% capacity factor
- Slightly increased wind in Vermont relative to the Proposed DSM Case (75 MW of new wind vs. 66 MW in the DSM case) but still less new wind than under the Reference Case (155 MW), reflecting the lower total energy demand due to DSM investments
- Output from all new and existing biomass and hydropower counted towards 75% goal, and all receives a price premium to reflect the policy mandate

The overall resource mix for the High Renewables Case is shown graphically in Exhibit 12.

[5] High renewables goals such as the one considered here logically must allow a broader range of qualified resources; if not, the paradoxical result would be the destruction of the market for low-or zero-emissions resources such as existing hydropower facilities.

Exhibit 12: Sources for Vermont's electric energy mix in 2025 under the High Renewables Case.



A. Costs and Benefits for Consumers

Construction, Operations and Maintenance Costs

The construction costs were calculated for each technology based on Synapse's assessment of cost and operational parameters for the northeastern United States, as detailed in Appendix A of this report. The construction and operation and maintenance (O&M) expenditure per MW for the region were combined with the MW installed of new renewable capacity to generate Vermont's aggregate investment in new renewable energy resources for each scenario. Exhibit 13 shows the construction and operations and maintenance costs by technology for the High Renewable Case, relative to the Reference Case.

Along with the renewable energy mandate described above, we include aggressive DSM investments in the High Renewable Case relative to the Reference Case, following the Proposed DSM Case. This decreases the energy requirement in Vermont and thus the requirement for renewable energy under the state RPS. As a result, the High Renewable Case actually results in a reduction in wind costs associated with construction ($325 million) and O&M ($61 million) relative to the Reference Case. Conversely, there is an additional $260 million investment in construction of distributed solar resources through the expanded Vermont feed-in-tariff program, along with $13 million in O&M costs associated with these resources during the plan period. This new solar energy, along with renewables from existing, expanded, and out-of-state sources of hydropower and biomass energy contribute to the renewable energy requirements. As with DSM savings, the costs and benefits associated with these resources after the study period are not considered.

Exhibit 13: Renewable Construction and O&M Costs for High Renewable Case (Current Year Dollars) relative to the reference case.

Technology	*Total (2012-2031)*
Solar Construction	$259.2
Wind Construction	-$325.4
Total New Construction	*-$66.2*
Solar O&M	$13.4
Wind O&M	-$61.0
Total O&M	*-$47.6*
Total Spending	**-$113.8**

Ratepayer Effects

Renewable investments affect consumers through higher electricity rates to pay for the incremental cost in new technology. In this study, we assumed that the amortized cost of construction and the ongoing O&M costs would be effectively added to energy costs throughout Vermont. At the same time, utilities and their ratepayers would realize the benefit of the energy and capacity produced by each resource. If the levelized cost of a resource is at or below the market price for energy and capacity, the premium falls to zero. For new solar and wind energy we calculated this by taking the difference between the levelized costs for each technology per Megawatt-hour (MWh) (see Appendix A) and the avoided capacity[6] and energy purchases—this is essentially the "premium" paid for renewable energy. For hydroelectric power that comes from out-of-state, the premium is unknown but would be small—our assumption was $5 per MWh.[7] The premiums for all renewable resources used in this study are shown in Exhibit 14.

[6] Avoided capacity costs were calculated based on the assumption that for the years 2012-2015 the New England capacity market will clear at the minimum de-list price of $1/MW-Month, and that thereafter it will clear at $5/MW-month throughout the study period, reflecting a general surplus of capacity due to RPS requirements and DSM investments throughout the region.

[7] For Hydro Quebec, the current contract mandates that proceeds from any emissions-related premium be shared evenly between Vermont and Quebec, Thus the additional Vermont cost for this resource is $2.50 per MWh.

Exhibit 14: Premiums for Renewable Energy ($2011 per MWh)

Technology	2012	2015	2020	2025	2031
Solar	$189	$142	$113	$92	$54
Wind[8]	$22	$15	$1	$0	$0
Biomass	$81	$75	$67	$54	$36
Hydro Quebec[9]	$2.5	$2.5	$2.5	$2.5	$2.5
Other Hydro	$5	$5	$5	$5	$5

Exhibit 15 shows that for the High Renewables Case, the bill impacts for renewable resources amount to $292 million over 20 years. This represents just under 0.2 cents per kilowatt-hour (kWh) on average for Vermont ratepayers, in 2011 dollars, over the study period.

Exhibit 15: Bill Impacts of Renewable Energy in the High Renewable Case relative to the Reference Case ($2011, unless otherwise noted)

Technology	2012	2015	2020	2025	2031	Total (2012-2031) Million $2011	Total (2012-2031) Million Current Dollars
Bill Impacts (millions)	$1.9	$2.3	$11.2	$15.2	$12.9	$208	$292
Load Forecast (GWh)	6,160	6,067	5,942	6,141	6,542	122,752	122,752
Impact (cents per kWh)	0.03	0.04	0.19	0.25	0.20	0.17	0.24

B. Jobs and Economic Benefits for Vermont

Net Economic Impacts

As with the Proposed DSM Case, the employment, wage income, and gross state product impacts of the High Renewable Case were calculated using the REMI model. Exhibit 16 shows these benefits on an annual basis, in constant dollars. We estimate that the High Renewable Case will generate nearly 15,000 jobs in Vermont and $1.53 billion in Gross State Product, in current dollars, during the study period.

A comparison of Exhibit 16 with Exhibit 11 illustrates that the net economic impacts of the Proposed DSM and High Renewable Cases are quite similar. This is due to the fact that the primary drivers of economic benefits—expanded investments in DSM and savings for Vermont ratepayers—are the same in both cases. These benefits are partially offset in the High Renewable Case by the cost of adding a premium value to numerous resources that would now qualify for

[8] Wind energy reaches "grid parity" after 2020, instead of a negative premium it was assumed that ratepayers would simply pay the same rate for this type in the future years.

special treatment under a broader renewable energy mandate, and by the cost of additional solar energy resources in Vermont relative to conventional resources. The total study-period benefits, and benefits per unit of spending, are shown in Exhibit 17 for Proposed DSM and High Renewable Cases.

Exhibit 16: Additional jobs (left axis) and other economic benefits (right axis, in constant dollars) associated with the High Renewable Case relative to the Reference Case, 2012-2031.

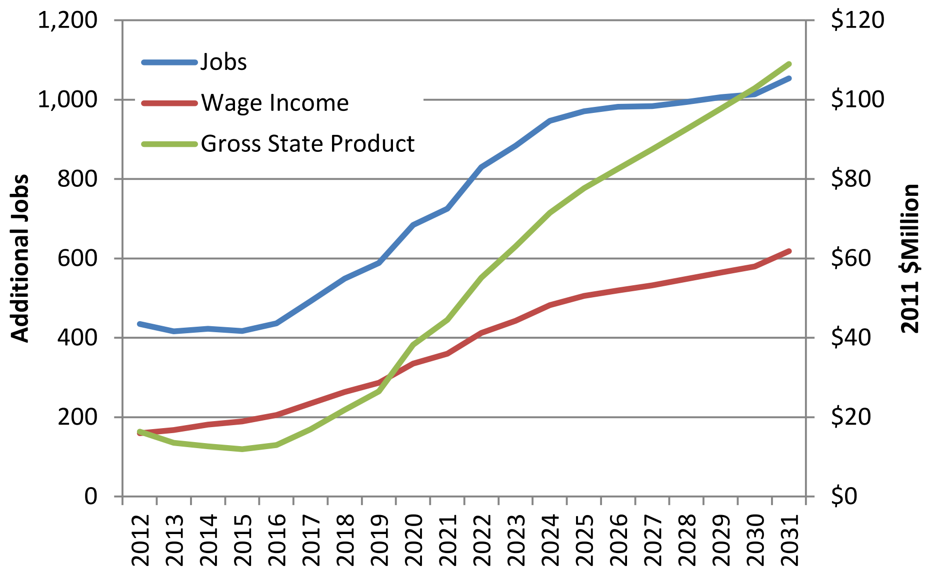


Exhibit 17: Leverage of Program Spending for Proposed DSM and High Renewable Cases, relative to the Reference Case ($2011). Costs and benefits that accrue after the end of the study period are not considered.

Scenario	Proposed DSM	High Renewable
Total Spending ($2011 Million)	$1,079	$1,287
Job-Years Relative to Reference Case	15,394	14,834
Job-years per $ million	14	12
GSP Benefit ($2011 Million)	$1,171	$1,055
$GSP benefit per Dollar Spent	$1.09	$0.82
Wage Income Benefit ($2011 Million)	$778	$759
Wage Income per Dollar Spent	$0.72	$0.59

5. Impact on Regional Pollutant Emissions

One of the primary benefits of implementing aggressive DSM and renewable energy investments in Vermont is to reduce the amount of pollutant emissions associated with the use of electricity by Vermonters. In general, most of these emissions do not take place within Vermont, because most of the electricity used in the state is imported from the surrounding regions. And the electricity that is produced in the state—whether hydropower, biomass, or wind—is unlikely to be displaced by the addition of clean resources such as additional energy efficiency or renewables.

However, the electricity that is imported from the New England Power Pool does come largely from fossil-fired plants, and these are the generating units that are most likely to be displaced by clean resources in Vermont. Using our dispatch model results, we can predict how much of these emissions would be avoided in each of the electricity scenarios, relative to the Reference Case.

Exhibit 18 presents the tons of pollution emissions avoided in New England as a result of each of the electric sector scenarios considered in this study.

Exhibit 18: 2025 and Total Cumulative Avoided Emissions for the Proposed DSM and High Renewable Cases relative to Reference Case (thousand tons). Pollution reduction benefits that accrue after the end of the study period are not considered.

Emission Type	Proposed DSM Case		High Renewable Case	
	2025	*Total (2012-2031)*	*2025*	*Total (2012-2031)*
SO_2	0.1	**2.6**	0.2	**3.4**
NO_X	0.04	**1.0**	0.1	**1.2**
CO_2	117	**2,567**	167	**2,962**

For perspective, the avoided CO_2 emissions benefit for the Proposed DSM Case is the equivalent of removing almost 425,000 cars from Vermont's roads. The High Renewable Case increases this benefit to almost 490,000 cars.[10]

[10] Assuming 12,000 miles traveled per year and an average fuel economy of 22.1 miles per gallon.

Appendix A: Renewable Energy Costs and Assumptions

The following is a description of renewable energy costs and assumptions used in Synapse's analysis.

A. Wind Costs

Exhibit A-1 compares several recent estimates of utility-scale wind project costs. "AEO 2011" refers to the input assumptions developed for EIA's 2011 Annual Energy Outlook. "Lazard" refers to the investment research organization of the same name. The E3 Analytics work was performed in early 2010 for the WECC region's Transmission Expansion Planning Policy Committee. "B&V 2011" is information taken from a May 2011 presentation of inputs to Black & Veatch's Gencost model.

Exhibit A-1: Comparison of Recent Wind Cost Estimates

	AEO 2011	Lazard 2010	E3 Analytics 2010	B&V 2011
Installed Cost ($/kW)	$2,438	$2,250-$2,600	$2,350	$2,000 - $2,500
Fixed O&M ($/kW-yr)	$28.07	$60.00	$50.00	?
Capacity Factor	34%	30%-40%	33%	$32-$42
Energy Cost ($/MWh)	$96	$85-$130	?	?

Since the 2009 – 2010 period, reduced demand has resulted in moderate but significant turbine price reductions, which we believe are reflected in the Black & Veatch estimate of installed costs, but not the others here.

We view wind as a fairly mature technology. We expect that there will be short-term fluctuations in project costs due to supply and demand dynamics in markets for turbines and other key inputs. Over the long term, we expect a trend of very modest cost reductions due to small improvements in technology and installation.

Exhibit A-2 shows our proposed costs for utility-scale wind projects in the Northeast, based on the data in Exhibit A-1 and data from other Synapse project work. Costs are stated in constant 2010 dollars. Installed costs and fixed O&M fall by 1% per decade. There are also modest increases in the capacity factor for new projects. Our fixed charge rate is based on a blended cost of capital to utility, merchant and municipal projects.

Exhibit A-2: Utility-Scale Wind Cost Forecast

	2011	2015	2020	2025	2030
Installed Cost($/kW)	$2,239	$2,228	$2,216	$2,205	$2,239
Fixed O&M ($/kW-yr)	$39.80	$39.60	$39.40	$39.21	$39.80
Capacity Factor	34.0%	34%	34.5%	34.5%	35.0%
Fixed Charge Rate	9.5%	9.5%	9.5%	9.5%	9.5%
Energy Cost ($/MWh)	$93	$93	$91	$91	$89
Energy net of subsidies ($/MWh)	$73	$73	$71	$71	$69

For the purposes of this analysis, we assume that the Production Tax Credit is not renewed after 2015, so unsubsidized costs would be attributed to projects coming on line after that date.

B. Biomass CHP Costs

The price paid for biomass CHP projects under Vermont's SPEED program starts at $121 per MWh and escalates to $141 per MWh in year 20. To represent the capital and O&M costs of these projects, we approximate the costs of a project with a levelized cost of $131 per MWh. We approximate these costs using a discounted cash flow model similar to the one used in developing the Vermont SPEED rates. Exhibit A-3 shows these costs. Note that these are only the project costs allocated to the electric side of the project. Total project costs would be higher. Note also that the federal grant or tax credit available to these projects is irrelevant here, because it will not affect what Vermont ratepayers pay for these projects.

Exhibit A-3: Project Costs Consistent with SPEED CHP Energy Rate

Electric Capacity (MW)	0.55
*Installed Cost ($/kW)	$4,745
Electric Capacity Factor	60%
Annual Output (MWh)	2,891
*Annual Fuel Cost ($)	$53,400
*Annual O&M ($)	$0
Return on Equity	10%
Levelized Cost ($/MWh)	$131

**Costs shown are the portion of total project costs allocated to electricity. Total project costs would be higher.*

C. Solar Photovoltaic (PV) Costs

We focus here on rooftop-mounted PV projects up to 2 MWs in size. This is a significant assumption, because the cost of utility-scale (ground-mounted) projects has fallen considerably over the past 18 months; however, the cost of small projects does not appear to have fallen as much.

Most new PV projects in Vermont will be paid under the SPEED program. Currently the rate for PV is $240 per MWh. Our analysis of current PV prices indicates that this rate is above the total levelized costs of many SPEED-eligible projects, especially the larger ones. This conclusion is supported by the robust PV activity in the SPEED program. Therefore, for this project we assume that new PV projects through 2014 receive the current SPEED rate, but that the rate paid to PV projects after 2014 is consistent with forecasted PV costs.

We present a cost forecast below, but we also acknowledge that this is a very dynamic period in PV markets and there is considerable uncertainty around long-term PV prices.

The cost reductions of 2010 have caused a number of analysts to forecast very low PV costs within 10 to 20 years. For example, a US DOE white paper recently forecasted 2016 prices for utility-scale PV at $2.65 per W_{AC}. In the Northeast (assuming a 22% capacity factor, consistent with a single-axis tracking system), this is consistent with a levelized cost of $107 per MWh with the federal grant, and $145 per MWh without it. While no one is predicting prices for small PV projects in this range, it gives a sense of how rapidly PV markets are changing.

The key driver of falling prices has been the supply side's response to the strong PV demand from Europe over the past five years. New silicon production capacity has come on line, as has new module production capacity. The global market for modules has also become more efficient and competitive. In early 2011 Barclays Capital reported an average selling price (ASP) for silicon panels of $1.95 per W_{DC} in Q1 2010 and a reduction to $1.65 in Q4. They projected a further decline to $1.45 by Q4 2011.

In 2010, Macquarie Capital's cost estimates were in the same range as Barclays' (although they showed a different trend in that year). For 2011, both companies were projecting average prices falling from about $1.65 to $1.45 per W_{DC}. Macquarie forecasted an average price of about $1.20 in Q4 2012.

In fact, module prices have fallen faster than Macquarie predicted. In July 2011 another Wall Street analyst, Jeffries & Co., revised their panel ASP projection to $1.20 – $1.30 per W_{DC} by Q4 2011. This is where Macquarie, in March, was predicting prices would be in Q4 2012.

However, there has also been discussion in the PV trade press about strategic pricing among panel manufacturers. For some months the Chinese government has been heavily subsidizing panel manufacture, and many panels are being sold at prices below cost there. More recently, there has been speculation that strategic pricing is spreading beyond China. This makes it difficult to interpret the 2011 module price drop, and it is reason to be conservative in projecting near-term price reductions from summer 2011 levels.

While there is anecdotal evidence from California markets of 2011 prices that reflect these module price reductions, there is little publicly available project data. So we are left to speculate that entities currently developing projects are enjoying considerably lower module costs than anticipated.

Our recent discussions with companies marketing residential PV systems suggest current costs in the range of $22,500 for a 4 kW system, or around $5,620 per kW_{AC}. With an 18% capacity factor, representative of rooftop mounted systems in the northeast, this translates to about $256 per MWh, with the federal grant. We estimate projects in the 1 to 2 MW range at $4,500 to $4,700 per kW_{AC}. Using the same capacity factor, this produces a levelizied cost range of $209 to $217 per MWh, again including the federal subsidy. These numbers are consistent with the high response to the SPEED program's current PV offer.

Exhibit A-4 shows our recommended PV costs for this project. We assume that the SPEED rate is paid through 2014, and we have approximated capital and O&M costs consistent with this rate for our cost analysis. In 2015 and after, we assume that the SPEED rate is periodically lowered to our forecasted rate. Further, as with wind projects, we assume that the federal subsidy is not renewed after 2015, and we attribute unsubsidized costs to projects installed after that date. We are open to input on these assumptions.

Exhibit A-4. PV Costs used in the analysis

	2011	2015	2020	2025	2030
Installed Cost ($/kW$_{AC}$)	$5,250	$4,300	$4,100	$3,900	$3,500
Capacity Factor	18.0%	18.0%	18.5%	18.5%	19.0%
Fixed O&M	$16.00	$16.00	$16.00	$16.00	$16.00
Inverter Replacement ($/kW-yr)	$12.00	$12.00	$11.50	$11.50	$11.00
Fixed Charge Rate	9.5%	9.5%	9.5%	9.5%	9.5%
Levelized Cost ($/MWh)	$240	$200	$186	$178	$157
Unsubsidized Cost ($/MWh)	$334	$277	$257	$246	$216

The reduction in installed costs forecasted here is consistent with a scenario in which US PV demand continues its rapid rise, module prices fall steadily but not precipitously, and the US supply chain becomes more competitive and efficient. We envision the installed costs at large, ground-mounted projects falling from about $3.70 per W$_{AC}$ today to about $1.90 by 2030. This scenario is more conservative than some other estimates, including the DOE white paper cited above, forecasting installed costs of $2.65 per W by 2016. We believe conservatism is in order due to the significant recent movement in PV prices and the fiscal pressures the country faces, which will make it increasingly difficult to gain support for reauthorizing existing subsidies or authorizing new ones.