Potential Cost Impacts of A Vermont Renewable Portfolio Standard

Prepared by:
Tim Woolf, David White, Cliff Chen, and Anna Sommer
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

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The contents, assumptions, and findings of this analysis are solely the responsibility of the authors.

1. Executive Summary

The Vermont legislature has recently passed legislation requiring the Vermont Public Service Board (PSB) to design a renewable portfolio standard (RPS) for Vermont. The PSB has established the Vermont RPS Collaborative to obtain input from relevant stakeholders. The PSB's goal is to develop draft RPS legislation to submit to the legislature by the end of 2003.

The purpose of this report is to provide quantitative estimates of the likely cost impacts an RPS in Vermont. The RPS legislation does not specify a renewable target, so we assume three different target levels in order to provide cost estimates under a variety of different approaches. We estimate the impacts of (a) a renewable target that starts at 0.5 percent in 2006, and increases by 0.5 percent per year through 2015; (b) a renewable target that starts at one percent in 2006, and increases by this amount per year through 2015; and (c) a renewable target that starts at two percent in 2006 and increases by this amount per year through 2015. We assume that these targets only apply to new renewable resources.

We prepare a supply curve of eligible renewable resources in New England and the region, and compare the costs of the renewables to the cost of the wholesale market price in New England. The difference represents a renewables premium, which then provides an estimate of the total cost of meeting the RPS. We estimate the premiums based on both the *marginal* renewable resource cost, which is assumed to set the market price for renewable energy credits in the region, and on the *average* renewable resource cost, which is assumed to reflect the costs associated with long-term contracts for renewables.

The RPS legislation allows a broad range of renewables to be eligible for meeting the RPS targets. Consequently, the current VT RPS would include several low-cost renewables (hydropower and certain biomass facilities) that are not eligible in other RPS markets in New England. These "Vermont-only" renewables are expected to be plentiful enough to serve the entire Vermont RPS requirement. They are also estimated to have costs that are lower than, or close to, future wholesale market prices, and thus result in negligible increases in electricity costs.

We have also assessed the cost impacts of revising the Vermont RPS to exclude some of the low-cost renewables that are not eligible in other RPS markets in New England. In this case, we analyze a New England-wide supply curve of renewable resources, where the prices paid for renewable energy credits in Vermont are the same as those paid elsewhere in New England.

We find that the Vermont RPS as currently designed will have very small impacts on Vermont retail electricity costs – if it has any impact at all. If the RPS target were set at one percent per year, increasing to 10 percent by 2015, the costs would be negligible. The Vermont RPS target could be as high as two percent per year, increasing to 20 percent by 2015, and the impact on retail costs would still be only 1.5 percent by that year.

If Hydro-Québec is unable to use its small hydropower generation to supply the Vermont RPS, then the renewable premiums will be noticeably higher, but costs of the VT RPS will still be quite low. If Hydro-Québec is excluded from our base case, the increase in retail electric costs is expected to be less than one percent by 2015. These results are presented in Table 1.1 below.

Table 1.1 Cost Impacts: 1% Target; VT-Only Renewables, Excluding Hydro-Québec

Year	Marginal Renewable Cost RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	Average Renewable Cost RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	1.70	0.2	0.03%	0.04	0.0	0.00%
2008	3.41	0.6	0.08%	0.08	0.0	0.00%
2009	5.11	1.3	0.16%	0.12	0.0	0.00%
2010	6.48	2.0	0.25%	1.18	0.4	0.05%
2011	7.84	3.0	0.37%	2.25	0.9	0.11%
2012	9.21	4.2	0.50%	3.31	1.5	0.18%
2013	9.76	5.1	0.61%	3.65	1.9	0.23%
2014	10.31	6.2	0.72%	3.99	2.4	0.28%
2015	10.86	7.3	0.84%	4.33	2.9	0.33%

If the Vermont RPS is modified to include only those renewables that are eligible in the Massachusetts and Connecticut renewable portfolio standards, then the renewable premiums will be higher still. However, even these renewable premiums will result in relatively moderate impacts on Vermont retail electric costs. Assuming an RPS target of one percent per year, the modified Vermont RPS would increase retail electric costs in 2015 by roughly 0.7 percent to 1.5 percent, depending upon whether the premiums turn out to be based on the average or the marginal costs. These results are presented in Table 1.2 below.

Table 1.2 Cost Impacts: 1% Target; New England RPS Perspective

Year	Marginal Renewable Cost RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	Average Renewable Cost RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	13.65	0.8	0.1%	4.23	0.3	0.0%
2007	16.80	2.0	0.3%	5.39	0.6	0.1%
2008	19.95	3.6	0.5%	6.55	1.2	0.2%
2009	23.10	5.7	0.7%	7.71	1.9	0.2%
2010	22.88	7.2	0.9%	8.17	2.6	0.3%
2011	22.67	8.7	1.1%	8.63	3.3	0.4%
2012	22.46	10.2	1.2%	9.10	4.1	0.5%
2013	21.50	11.3	1.3%	9.04	4.7	0.6%
2014	20.53	12.3	1.4%	8.97	5.4	0.6%
2015	19.57	13.2	1.5%	8.91	6.0	0.7%

The cost impacts of a Vermont renewable portfolio standard will be heavily influenced by the wholesale market price in New England. We have conducted two analyses to test the sensitivity of our results to this input: a low case assumes that the New England wholesale market price is 20 percent lower than our base case in all years(which would make them lower than today's prices), and a high case assumes that the wholesale market prices is 20 percent higher in all years.

In the Low Wholesale Price case, the Vermont-only RPS would still have a small cost impact, remaining under one percent by 2015. If Hydro-Québec generation is excluded, then the cost impact would still be less than two percent of retail costs by 2015. From the New England RPS perspective, the Vermont retail cost impact would reach a peak of 2.3 percent by 2015.

If the wholesale prices turn out to be 20 percent higher than our forecast, then the cost impacts of all the scenarios would be reduced considerably. Even from the New England RPS perspective, the Vermont retail electric costs would not increase by more than 0.7 percent. The three figures below summarize the results of our wholesale price sensitivity analysis. These figures present the RPS impacts based on marginal renewable costs; the results based on average renewable costs are correspondingly lower.

Figure 1.1 Cost Impacts: VT-Only Renewables; Wholesale Price Sensitivities

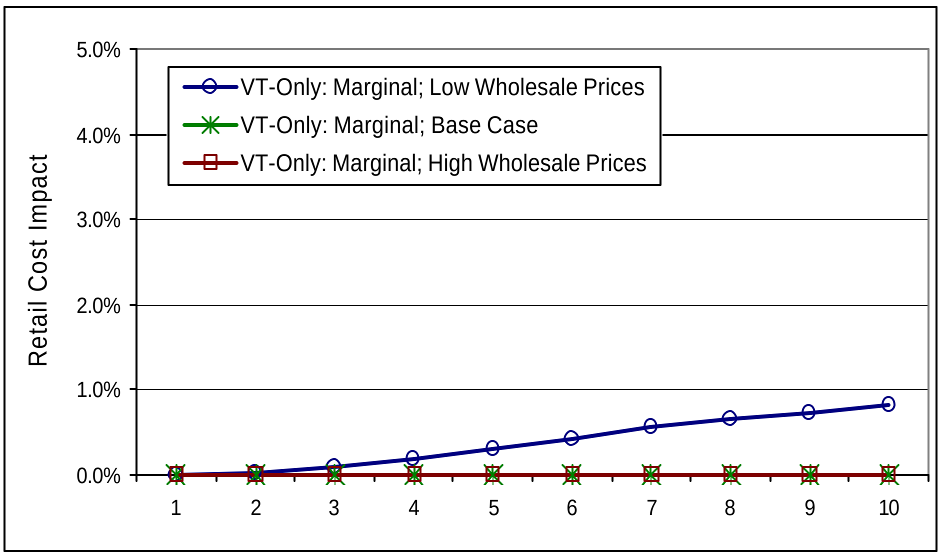


Figure 1.2 Cost Impacts: VT-Only Renewables, Excluding HQ; Wholesale Price Sensitivities

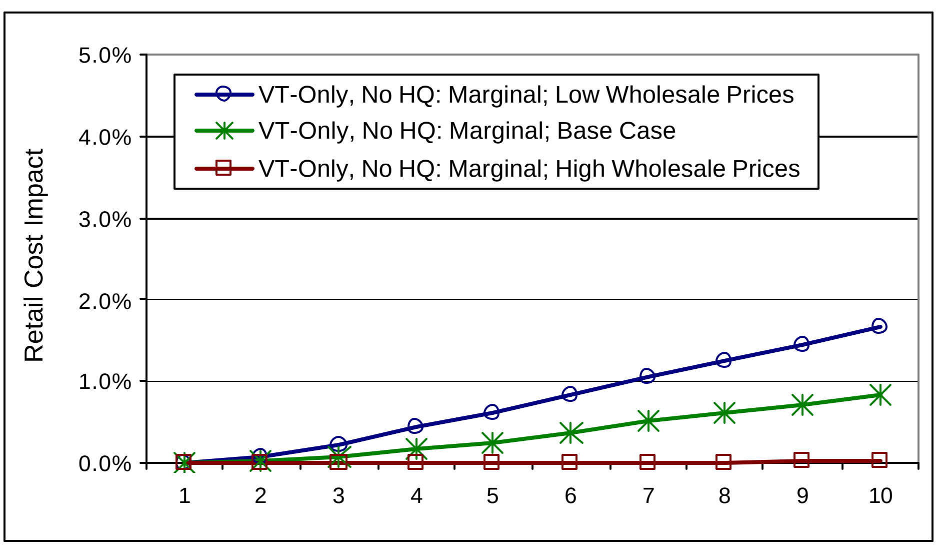
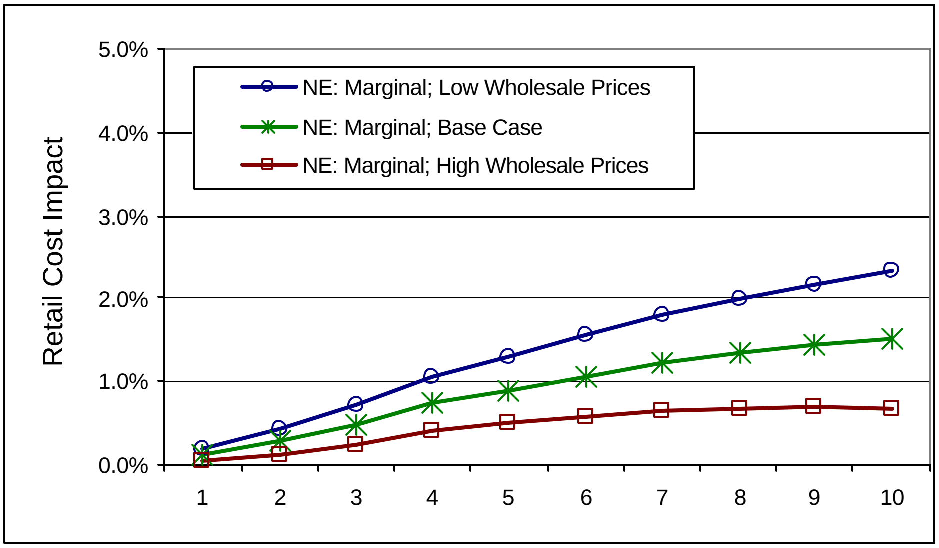


Figure 1.3 Cost Impacts: New England RPS Perspective; Wholesale Price Sensitivities



2. Overall Methodology

We began our analysis with a review of the existing literature and readily available data regarding renewable resource availability and costs in New England. Our analysis draws heavily from recent studies of RPS costs in New England (Grace et. al. 2002, and Smith et. al. 2000) and New York (NYDPS 2003).

Location of Eligible Resources

Renewable resources built and operated anywhere in New England will be eligible for the Vermont RPS. Accordingly, we have analyzed the cost of the Vermont RPS using a New England-wide assessment of renewable resources. We consider the supply of renewable resources throughout all of New England, and we compare this to the demand for renewable resources throughout New England. The demand for renewables will include the demand driven by the renewable portfolio standards in Massachusetts and Connecticut, as well as the demand driven by the Vermont RPS. The demand for renewables will also be affected by the extent to which suppliers offer, and customers purchase, "green power" above and beyond that provided through renewable portfolio standards.

The Generation Information System (GIS) established and operated by ISO-New England (ISO-NE) will provide renewable generators with a means of accounting for the purchase and sale of renewable energy. The GIS will enable renewable generators to produce Renewable Energy Credits (RECs) that can be used to demonstrate compliance with an RPS anywhere in New England. This New England-wide system of tradable credits ensures that the market for renewables will be consistent region-wide, and that the premium paid for renewable generation will be the same in all states with an RPS.[1] In other words, the New England GIS allows us to analyze the costs of the Vermont RPS on a New England-wide basis. The New England GIS will also provide regulators with a mechanism for ensuring compliance with the RPS requirements.

We also assume that imported power from New York and Canada will be eligible to comply with the Vermont, Massachusetts and Connecticut renewable portfolio standards. These two regions will need to establish a system for creating and accounting for Renewable Energy Credits that is consistent with the New England GIS, in order to fully participate in the New England RPS market. In the absence of such a system, renewable generators will have to establish bilateral contracts with purchasers in New England to demonstrate that the renewable power and its attributes are being delivered into New England.

The Renewable Energy Premium

We estimate the cost impacts of the Vermont RPS by determining a "renewable energy premium." This premium (in $/MWh) represents the extent to which the cost of the renewable energy exceeds the cost of energy that could be purchased from the New England wholesale

[1] Some states define renewable eligibility differently, which creates slightly different markets for RECs across the states. This issue will be addressed in more detail below.

electricity market. This premium can be viewed from two perspectives. First, from the ratepayer's perspective, it represents the additional costs that are required to meet the RPS, relative to simply purchasing the energy from the New England wholesale electricity market.[2] Second, from the perspective of the renewable generator developer, the renewable energy premium represents the amount of revenue necessary to support the renewable project, above the revenue that can be obtained from selling the energy as a commodity into the wholesale spot market. From this latter perspective, the renewable premium represents the additional revenues necessary to make a renewable project profitable and therefore viable.

The renewable energy premium will be different for each type of renewable generator. In order to estimate the cost impact of the Vermont RPS, we are interested in the total renewable energy premium that is created by the combination of all the renewable resources meeting the RPS in any one year. In theory, this total renewable premium should be equal to the premium of the "marginal" renewable resource, because the marginal resource would set the price for all of the renewable energy credits. However, in practice the total renewable premium might be considerably lower than the marginal renewable costs, as renewable developers establish long-term contracts (at rates closer to their actual costs plus profits) to support the financing of their projects.

In this study we estimate and present *both* the RPS cost impacts based on the marginal renewable costs and those based on the average renewable costs. This approach provides a range within which the actual premiums and costs are likely to fall. However, in drawing our general conclusions we rely more heavily upon the results based on marginal renewable costs, because we expect the actual RPS costs to determined more by the marginal results than the average.

We find that some of the low-cost renewable generators are expected to cost less than the wholesale price of electricity in New England. In these cases, we assume that the plant owners would receive the wholesale price for this renewable generation, and thus the renewable premium for these generators would be zero. In practice, these renewable generators could reduce the wholesale electricity price by displacing the most expensive generator on the system at the time of generation. However, we do not capture those wholesale cost savings in our estimates of the RPS impacts.

The New England wholesale electricity prices will play a critical role in determining the renewable energy premium. We use the futures market for wholesale energy in New England to forecast the 2004 wholesale market price for the region. We then assume that in 2010 there will be a need for a new, as yet unplanned, natural gas combined cycle facility to meet growing demand and reliability requirements, and that this facility provides a proxy for the New England wholesale electric price in that year. Finally, we assume that the wholesale electricity costs increase linearly from 2004 to 2010. The details of the New England wholesale price estimate are provided in Section 3 below.

[2] This is a very simplistic comparison. There are many ways that load serving entities and electric utilities can purchase power at prices lower than the New England wholesale spot market. Furthermore, the benefits offered by renewable resources are different, and sometimes considerably higher, than those offered by wholesale spot market purchases.

Comparison of Renewable Supply and Demand

We estimate the RPS demand in New England by adding the VT RPS requirements to those in Massachusetts and Connecticut.[3] To this we add an estimate of the extent to which green power demand will increase the overall demand for renewables in New England. We choose three illustrative RPS targets for Vermont: 0.5 percent per year for ten years, one percent per year for ten years, and two percent per year for ten years, all beginning in 2006. The details of this approach are provided in Section 4 below.

We then develop a "supply curve" of the cost and amount of energy available from renewable resources, to compare with the RPS demand. This supply curve includes all of the types of renewable resources that are eligible for the renewable portfolio standards throughout New England. We use the most recent, readily available data to prepare a supply curve for each renewable type, for each of three "snapshot" years of our analysis: 2006, 2009 and 2012. The supply curve ranks the renewables in order of lowest to highest cost. A comparison of the RPS demand curve with the renewable supply curve provides the mix and amount of each renewable type that is most likely to meet the RPS in any given year. From this we estimate the total cost of the renewable resources in the RPS, as well as the average and marginal renewable premiums. The details are provided in Section 6 below.

Finally, we use the renewable premiums to estimate the impact of the RPS costs on total electricity costs and typical customer bills. The renewable premium (in $/MWh) times the amount of renewable energy in each year (in GWh) provides the total RPS cost, which is compared to future electricity costs and customer bills. The results are presented in Section 7 below.

[3] We do not include the Maine RPS requirement in our New England RPS demand calculation, for reasons described in Section 4.

3. Wholesale Market Prices in New England

We use the futures market for wholesale energy in New England to forecast the 2004 wholesale market price for the region. As of September 9, 2003 the futures market price for New England energy for calendar year 2004 was $40.58/MWh. This represents a weighted average of the peak and off-peak prices. It also represents an average of the process asked by sellers and prices offered by bidders. (Natsource 2003)

The ISO-NE summer reserve margin is expected to be 28 percent in 2003, and to decline slowly after that. (ISO-NE 04/2003) This suggests that the region currently has plenty of generation capacity, but that new capacity will be needed in several years as a result of load growth. We assume that in 2010 there will be a need for a new, as yet unplanned, natural gas combined cycle facility to be installed, and that this facility provides a proxy for the New England wholesale electric price in that year. Table 3.2 provides a summary of our assumptions regarding the cost of the natural gas combined-cycle facility.

The forecast of gas prices plays an important role in the natural gas combined-cycle cost estimate. To forecast natural gas prices we use the NMEX futures price forecast for Henry Hub gas prices for 2004 through 2009. (Wiser et. al. 08/2003) These are adjusted to account for the difference between Henry Hub gas prices and New England gas prices. (Wiser et. al. 09/2003) For years after 2009 we assume that natural gas prices escalate at the annual growth rates in the AEO 2003 forecast prepared by the Energy Information Administration. (EIA 01/2003) The resulting gas prices are presented in Table 3.3 below.

Table 3.2 Assumptions Regarding the Cost of a Future Natural Gas Combined Cycle

Cost Category	Cost	Source
Overnight capital costs ($/kW)	529	EIA 01/2003
Interest during construction adjustment	1.185	12% interest for three years
Interconnection costs ($/kW)	0	built at existing plant site
Total capital costs ($/kW)	628	calculated from above
Capital recover factor	13.6%	debt (8%), equity (16%), 60/40 ratio
Variable O&M ($/MWh)	2.12	EIA 01/2003
Fixed O&M ($/kW-yr)	12.8	EIA 01/2003
Heat rate (MMBtu/kWh)	7000	EIA 01/2003
Natural gas price ($/MMBtu) in 2010	4.64	gas futures, then EIA 01/2003
Year installed	2010	based on New England needs
Capacity factor	85%	base load operation
Total Costs in year installed ($/MWh)	52.4	calculated from above

Note: All costs are in 2003 dollars. The fixed O&M assumption is likely to be conservative because EIA does not include administration and general costs.

Finally, we assume that the wholesale electricity costs increase linearly between 2004 prices and the cost of a new natural gas combined-cycle in 2010. This assumption is based on the premise that prices will increase as capacity becomes increasingly scarce, up to the point where the price reaches the cost of a new power plant. Table 3.3 provides a summary of the resulting New England wholesale electricity prices.

Table 3.3 New England Gas and Wholesale Electricity Prices: 2003-2015

Year	Natural Gas Prices ($/MMBtu)	Wholesale Electricity Price ($/MWh)
2004	4.87	40.58
2005	4.57	42.56
2006	4.55	44.53
2007	4.54	46.51
2008	4.53	48.48
2009	4.47	50.46
2010	4.64	52.44
2011	4.79	52.70
2012	4.93	52.96
2013	5.02	53.23
2014	5.09	53.49
2015	5.09	53.76

4. The Vermont RPS

A copy of the legislation is included as Attachment A to this report. It defines renewable energy quite broadly as "energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate." The RPS legislation specifies that hydro generation is eligible for the RPS only if it is produced from facility with a generating capacity of 80 megawatts or less. The legislation specifically allows biomass generation to be eligible for the RPS, as long as it is produced from "methane gas and other flammable gases produced by the decay of sewage treatment plant wastes or landfill wastes and anaerobic digestion of agricultural products, byproducts, or wastes."

Based on these definitions, we have included the following resource types in our analysis: wind, landfill gas, biomass co-fired with coal plants, biomass co-fired with gas plants, increased biomass generation at existing facilities, dedicated biomass plants, and hydro facilities of less than 80 MW. However, some of these renewable types are not eligible for the renewable portfolio standards in Massachusetts or Connecticut. In those cases, we have limited the amount of renewable energy to that which could be used to meet the Vermont RPS.

We expect that there will be a substantial amount of relatively low-cost renewables available from New York and Canada. We have assumed for the purpose of this analysis that these imports will be eligible for the Vermont RPS.

For the purposes of this study, we have limited our analysis to include only new renewable generators, as opposed to those renewable generators in operation today. If existing renewable generators are eventually deemed to be eligible for the Vermont RPS, then additional analysis will need to be undertaken to estimate the costs of that approach.

The percentage targets for the Vermont RPS have not yet been determined. One of the objectives of this study is to provide cost information that might assist with that determination. Accordingly, we have estimated the cost impacts of three illustrative RPS targets:

- <u>One-half percent per year</u>. Beginning in 2006 the RPS target will be 0.5 percent, and will increase by 0.5 percent per year until 2015 when it reaches five percent.
- <u>One percent per year</u>. Beginning in 2006 the RPS target will be one percent, and will increase by one percent per year until 2015 when it reaches ten percent.
- <u>Two percent per year</u>. Beginning in 2006 the RPS target will be two percent, and will increase by two percent per year until 2015 when it reaches twenty percent.

The energy associated with these three targets are presented in Table 4.1 below.

Table 4.1 Renewable Energy Required By Three Illustrative Vermont RPS Targets (GWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Half Percent	30	60	91	124	157	191	226	262	299	336
One Percent	59	120	183	247	314	382	453	524	597	672
Two Percent	119	240	365	494	628	765	906	1,049	1,195	1,345

Note: Our Vermont electricity sales forecast is presented in Section 6.

The total demand for renewable energy in New England will equal the Vermont RPS demand plus the demand created by the Massachusetts and Connecticut renewable portfolio standards, plus the demand created by customers wishing to purchase green power.[4] Table 4.2 presents those demand levels, plus the total renewable energy demand in New England. The Massachusetts, Connecticut and Vermont retail electricity sales for 2000 were all taken from EIA 2002, and were forecast to grow at the New England retail sales growth rate from the ISO-NE CELT report (ISO-NE 04/2003).

Table 4.2 Renewable Energy Required to Meet New England Renewable Energy Demand (GWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
VT (One Percent)	59	120	183	247	314	382	453	524	597	672
Massachusetts	1389	1,689	1,999	2,318	2942	3,585	4,246	4,915	5,601	6,304
Connecticut	644	1,142	1,655	2,016	2,387	2,425	2,462	2,493	2,526	2,558
Green Power	100	150	200	250	300	350	400	450	500	550
Total New England	2,193	3,101	4,036	4,831	5,943	6442	7,560	8,383	9224	10,085

4 We do not include the Maine RPS requirement in our New England RPS demand calculation. The Maine RPS target is 30% of retail sales, but it allows existing renewables to meet this target. The amount of existing renewable generation in Maine (from existing hydro and biomass) is currently roughly 50% of retail sales; therefore this generation is expected to serve the entire Maine RPS demand. The Maine RPS will therefore not contribute to the demand for new renewables, which is the subject of this report.

5. Cost and Availability of Renewables in the Region

5.1 Hydropower

New England Hydro

Hydropower could play a significant role in the Vermont RPS if it is considered an eligible technology. The technical potential for the development of small hydropower sites and upgrades of existing facilities in New England is considerable, particularly in Vermont and Maine. We analyzed three categories of hydro sites: repowering (new turbines at existing hydro facilities), existing dams without turbines, and new projects at undeveloped sites. Studies done by the Idaho National Engineering and Environmental Laboratory (INEEL) indicate that there is technical potential in New England for 140 MW of hydro repowering and 412 MW of hydro development at existing dams. (INEEL 1995-1998) We excluded new projects at undeveloped sites in New England from our analysis due to the significant regulatory barriers that such projects would face and their higher capital costs.

The vast New England hydro potential notwithstanding, some hydro developers and experts in the region are pessimistic about the future of an industry that has become largely stagnant in recent years. They believe that the development of new hydro resources will be severely constrained by the following reasons:

- Most of the existing hydropower sites in the region are close to fully developed and have little exceedance, meaning that upgrades or repowering may not significantly improve their capacity
- Compared to other generating facilities, hydro projects are very long lived from an accounting perspective. Operating lives are typically assumed to be about 50 years. An RPS incentive that lasts 10 to 15 years might provide some financial stimulus, but only if hydro developers are assured that the RPS premium will be substantial and sufficient over the life of the incentive.

In June 2003, INEEL released its Hydropower Resource Economics Database, which contains detailed cost estimates for over 2,000 potential hydro projects across the country. The database includes detailed cost estimates for each project, including capital and O&M costs, and also has approximate site probability factors for each project.

The INEEL database contains 19 hydro repowering sites in New England comprising 126 MW of capacity with site probabilities of at least 0.50. The median per unit capital cost of developing these sites is about $1,500/kW. Based on the pessimistic outlook of hydro developers in the region, we assumed that 25 percent of the 126 MW of potential repowering capacity is available to meet the Vermont RPS.

The database also includes 18 existing dam sites in New England with site probabilities of at least 0.75, comprising 175 MW of capacity. The median cost of these sites is $1,900/kW. Because of the higher average probability factor of these sites, we assumed that 50 percent of the 175 MW of existing dam resource potential is available to meet the RPS. We also imposed a 20 percent cost premium on the INEEL cost assumptions to reflect the "real world" experience of hydro developers.

We determined a generic, New England-wide capacity factor by calculating the weighted average of the state-by-state capacity factors provided in the INEEL study.

Table 5.1 New England Hydro Availability and Cost Assumptions

	2009	2012	2015
Hydro Repowering			
Available Capacity (MW)	10	21	31
Available Energy (GWh)	47	98	144
Levelized Cost ($/MWh)	$52.7	$52.7	$52.7
New Projects at Existing Dams			
Available Capacity (MW)	29	57	86
Available Energy (GWh)	135	265	400
Levelized Cost (c/kWh)	$68.6	$68.6	$68.6

Table 5.2 Cost and Performance Assumptions for New England Hydro

	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
Hydro Repowering	0.53	$1,800	$18.0	$4.3
Existing Dams	0.53	$2,280	$16.0	$3.4

Québec Hydro

In Quebec, several new hydro projects are in the planning and construction stages, including a handful of projects that fall within the proposed 80 MW size threshold. Last year, Hydro Quebec issued an RFP for hydro projects of 50 MW or less. Three projects

Last year, Hydro Quebec issued an RFP for hydro projects of 50 MW or less. Three projects at existing dam sites were selected, totaling 75 MW, or 337 GWh of energy, at an average price of just 4.3 cents Canadian per kWh.[5] The projects are expected to be commissioned for operation in 2005-2006. The cost of these projects is consistent with Canadian cost estimates for small hydro projects, which typically range from 4.5 to 6 cents per kWh.[6]

Six other publicly owned sites have also been allocated for potential hydroelectric development. Hydro-Quebec estimates the potential capacity of these sites to be 34 MW, although this appears

[5] Canadian Electricity Association (CEA). *Small hydroelectric generations: Hydro-Quebec Production announces the selected bidders*, November 26, 2002, available at http://www.canelect.ca/english/News2002/HydroQuebec63.html

[6] Environment News Service (ENS). *Quebec Proposes 36 Hydroelectric Dams on 24 Rivers*, by Martin Stone, July 25, 2001.

to be a conservative estimate.[7] While the cost of developing these sites is probably low relative to wholesale electricity prices in New England, it is unknown how much, if any, of the generation from these sites will be exportable to New England, given transmission constraints and political factors.

In addition to these independent generator projects, Hydro-Quebec is in the process of planning and building several hydroelectric sites across the province. Among these are the Chute Allard (70 MW) and Rapides-des-Coeurs (80 MW) run-of-the-river projects in the Haut Saint-Maurice region, which are in the feasibility study phase. The Mercier Power Station is a 60 MW project at an existing dam that is currently under construction. According to the Hydro-Quebec website, the cost of the project is $95 million (CAD), or roughly $1,170/kW in USD.[8] Table 5.3 presents a list of the hydro projects of 80 MW of less that are currently planned or under construction in Quebec.

Table 5.3 Hydro Projects at Existing Dams of 80 MW or Less Under Construction or Planned in Quebec

Project	Size (MW)	Date Operational	Status	Capacity Factor	Cost (CAD)
Magpie	38	2005-2006	Planned	0.51	4.3 c/kWh
Matawin	12	2005-2006	Planned	0.51	4.3 c/kWh
Courbe du Sault	25	2005-2006	Planned	0.51	4.3 c/kWh
Chute Allard	70	2008	Feasibility Study	0.60	?
Rapides-des-Coeurs	80	2006	Feasibility Study	0.66	?
Mercier	60	2006	Construction	0.59	$95 million

Note: Capacity factors and cost for the Magpie, Matawin, and Courbe du Sault projects are averages of the three projects.

The generation from hydro projects such as these could swamp the Vermont RPS, if the electricity they generate can be economically delivered across the border. There does not appear to be a clear pattern to the cost of these projects. While the 60 MW Mercier existing dam project only cost $95 million CAD, a turbine replacement/ repowering project at the Outardes-4 Generating Station will increase capacity by 55 MW at a cost of $141 million CAD, or about $1,900/kW USD. However, a similar upgrade project at the Outardes-3 Generating Station will increase the facility's capacity by 250 MW at a cost of just $177 million CAD, or $520/kW USD.[9]

Two completed projects at existing dams in Ontario also showed a wide range of costs. An 800 kW new facility at an existing dam cost $1.8 million CAD, or about $1,700/kW USD, and a 350

[7] Quebec Ministry of Natural Resources. *List of eligible sites for Hydro-Quebec's call for tenders*, available at http://www.mrn.gouv.qc.ca/english/energy/forces/forces-new-listhq.jsp.

[8] http://www.hydroquebec.com/mercier/index.html

[9] Hydro-Quebec website.

kW repowering cost approximately $300,000 CAD, or just $630/kW USD.[10] Table 5.4 shows the range of cost from these projects along with the Hydro-Quebec Outardes projects.

Table 5.4 Hydro Upgrades and Repowering in Quebec and Ontario

Project	Project Type	Original Capacity (MW)	Upgraded Capacity (MW)	Estimated Cost ($000 CAD)	Cost per additional kW ($USD)
Outardes-3	Upgrade	756	1006	$177,000	$520
Outardes-4	Repowering	630	685	$141,000	$1,900
Almonte	Repowering	-	0.35	$300	$630
Cordova	Existing Dam	-	0.8	$1,800	$1,700

The current capacity of hydro projects in Canada of 50 MW or less is 3,160 MW.[11] One could assume that a third of this capacity, or about 1,000 MW, is situated in Quebec. The New York RPS Cost Analysis assumed 300 MW of available hydro upgrade capacity in Quebec. We assumed 150 MW of upgrade and existing dam capacity, or about 15% of existing small hydro capacity in the province, is available to meet the Vermont RPS. We adopted cost assumptions from the NY RPS study and OEI 2003, and adjusted the three-point resource supply curve to reflect the broad range of costs described above.

If the Chute Allard and Rapides-des-Couers projects are developed as planned, they will comprise 150 MW of new hydro at undeveloped sites. Assuming that they are developed and that one-third of their output is exportable to New England would result in 50 MW of available undeveloped hydro capacity. Lacking specific cost data for these projects, we have relied on a report that lists the costs of several recently developed or under construction small hydro projects in Ontario.[12] The average per unit capital cost of those projects is $1,890/kW.

[10] CanREN website, 9/5/2003.

[11] http://www.canren.gc.ca/resou_asse/index.asp?CaId=54&PgId=274

[12] Generating Investment in Ontario: Final report of the Renewable Energy Task Force, Appendix 1, December 12, 2002.

Table 5.5 Quebec Hydro Availability and Cost Assumptions

	2006	2009	2012	2015
Hydro Upgrade – Quebec				
Available Capacity (MW)	45	90	150	150
Available Energy (GWh)	177	355	591	591
Levelized Cost (c/kWh)	$53.5	$53.5	$53.5	$53.5
New Hydro – Quebec				
Available Capacity (MW)	15	30	30	50
Available Energy (GWh)	66	131	219	219
Levelized Cost ($/MWh)	$61.8	$61.8	$61.8	$61.8

Table 5.6 Pe rformance and Cost Assumptions for Quebec Hydro

	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
Hydro Upgrade Quebec	0.45	$1,200	0	$5.0
New Hydro Quebec	0.50	$1,900	0	$5.0

5.2 Biomass

Co-Firing with Fossil Fuel

Biomass feedstock can be co-fired with coal or natural gas in plants that are retrofit with the proper equipment. It appears that biomass co-firing with both coal and natural gas will meet the current eligibility requirements of the Vermont RPS, but only co-firing with natural gas, which is a more advanced, low-emission technology, will qualify for the Massachusetts and Connecticut standards.

We adopted many of the coal co-firing cost assumptions of the Massachusetts RPS study. (Smith et. al. 2000, and Grace et. al. 2000) Since the original Massachusetts RPS cost study was developed, it has been determined that biomass co-firing with coal is not an eligible resource under the Massachusetts RPS or the more restrictive tier of the Connecticut RPS. Thus, we have downgraded the available coal co-firing capacity from that study to reflect the likelihood that less capacity will be devoted to this technology. We assume that the average cost of biomass fuel will be $2.00/MMBtu, based on the findings of the Massachusetts RPS Cost Analysis and corroborated by biomass experts in the region.

A California Energy Commission report on biomass co-firing with natural gas assumes that the capital cost of co-firing retrofits is currently $700/kW (CEC 2002). Although technological enhancements and improved economies of scale could reduce the cost in the next several years, it is unclear how significant an impact the technology will have in New England, and we have conservatively assumed that the capital cost will remain at $700/kW through 2015.

Biomass fuel availability may be the limiting factor in determining the co-firing resource availability. The New England states that have the greatest supply of low-cost mill wastes and forest residues are also the ones with the least natural gas fired generation. Maine, New Hampshire, and Vermont all have access to low-cost biomass feedstock, but (with the possible exception of Maine) do not have sufficient natural gas capacity to generate significant amounts of biomass co-firing.

According to EGRID data, in 2000, Maine, New Hampshire and Vermont combined for about 3,350 GWh of natural gas fired generation. Assuming that two-thirds of this generation is located within range of low-cost biomass feedstock and not subject to expensive permitting requirements (i.e. Clean Air Act New Source Performance Standards), we calculate approximately 300 MW of gas-fired generation that is available for retrofitting with biomass gasification systems. Assuming three percent annual growth in natural gas combined cycle generating capacity (which is similar to EIA projections for New England), there would be about 430 MW of capacity in 2015. Assuming that 10 percent of a plant's fuel input is biomass, this yields 43 MW of available resource.

Our biomass co-firing assumptions are detailed in Tables 5.7 and 5.8 below.

Table 5.7 Biomass Co-Firing Availability and Cost Assumptions

	2006	2009	2012	2015
Co-Firing with Coal				
Available Capacity (MW)	0	25	50	50
Available Energy (GWh)	0	186	372	372
Levelized Cost Premium ($/MWh)	–	$10.1	$10.1	$10.1
Co-Firing with Natural Gas				
Available Capacity (MW)	14	29	43	43
Available Energy (GWh)	113	234	347	347
Levelized Cost Premium ($/MWh)	($5.7)	($4.9)	($9.2)	($10.7)

Note: The Levelized Cost Premium for the co-firing technologies represents the incremental cost of each MWh of biomass-fired generation over the generator's base generation cost.

Table 5.8 Cost and Performance Assumptions for Biomass Co-Firing

Technology	Capacity Factor	Capital Cost ($/kW)	Fixed O&M Cost ($/kw)	Biomass Fuel Cost ($/MMBtu)[a]	Heat Rate (Btu/kWh)
Co-Firing with Coal	0.85	261	$10.0	$0.2	10,489
Co-Firing with Natural Gas	0.92	$700	$5.0	$(2.76)[b]	9,300

Notes:
[a] *Represents the cost premium of biomass fuel over coal, which is assumed to cost $1.80/mmBtu*
[b] *Average of the difference between biomass fuel cost and the natural gas forecast price in each of the snapshot years.*

Increased Capacity at Existing Biomass Plants

Existing biomass plants can make capital improvements to expand their capacity. If the increased output from these plants is considered eligible by the Vermont RPS, this resource can play a significant role in meeting the Vermont renewable generation targets. Since the release of the original Massachusetts RPS cost study, it has become apparent that increased biomass capacity at existing plants will not qualify for the Massachusetts or the more restrictive tier of the Connecticut renewable portfolio standards (Class I).

Because existing biomass plants are not eligible for the Massachusetts and Connecticut standards, the increased output from the large stock of these plants in New England could dominate the Vermont RPS. According to the Department of Energy's Renewable Energy Plant Information System (REPiS), there is roughly 785 MW of operating biomass capacity in New England. As seen in the following table, the majority of this capacity is found in Maine.

Table 5.9 Existing New England Biomass Plants by State

State	Number of Plants	Total Capacity (kW)
Connecticut	1	150
Maine	24	561,100
Massachusetts	2	18,530
New Hampshire	12	129,100
Rhode Island	0	0
Vermont	7	75,900
Total	**46**	**784,780**

Assuming that several of these plants are subject to economic dispatch and operating at low capacity factors, one supposes that their eligibility in an RPS would result in an increase in the prices they receive, thus allowing many plants to increase their output. It is highly possible that these plants could do so without incurring additional capital costs, since their operating permits probably do not stipulate maximum generating outputs or capacity factors. A more likely scenario would involve some plants needing to purchase NOx emission allowances to cover their increase in emissions or retain credits that they otherwise would have sold. These costs are probably negligible compared to the capital costs of NOx control technologies such as SNCR or low-NOx burners.

The eleven largest New England biomass plants for which EGRID data is available operated with an average capacity factor of 0.71 in 2000. Using the Massachusetts RPS cost study assumptions, and a biomass fuel cost of $2.00/mmBtu, the marginal cost of operation of these plants is only $33.7/MWh. This very low cost suggests that the RPS premium necessary to encourage additional generation at these plants ought to be very small, but also implies that many of the existing biomass plants in the region may already be operating at or near their availability factor.

We assumed that the existing biomass plants in New England are capable of increasing their capacity factor by an average of five percent without incurring significant pollution control costs. At an average capacity factor of 0.75, this equals about 37 MW of increased capacity. We applied a $1.5/MWh NOx emission adder to the plants' operating cost (calculated using a NOx emission rate of 3.0 lb/MWh and a NOx emission allowance cost of $2,350 per ton based on current SIP Call forward trading prices[13], and applied to 5/12th of the increased generation).

Table 5.10 Existing Biomass Availability and Cost Assumptions

	2006	2009	2012	2015
Available Capacity (MW)	18	35	35	35
Available Energy (GWh)	121	241	241	241
Levelized Cost ($/MWh)	$33.5	$33.5	$33.5	$33.5

Table 5.11 Cost and Performance Assumptions for Existing Biomass

Capacity Factor	Capital Cost ($/kW)	Fixed O&M Cost ($/kw)	Variable O&M ($/MWh)	Biomass Fuel Cost ($/mmBtu)	Heat Rate (Btu/kWh)
0.75	0	$0.5	$2.0	$2.0	15,000

Manure Digestion

Anaerobic manure digestion technology provides farm operations with a viable option for on-site energy generation and organic waste management. Due to its small scale and limited applicability, however, it is expected to play a limited role in the Vermont RPS.

We adopted the major manure digester cost and performance assumptions from the New York RPS report. The resource availability was determined by estimating the number of dairy farms in New England with greater than 200 cows (200 head was suggested as a practical threshold in the New York report), estimating the number of cows at each farm, and applying the 1200 kWh of digester production per cow per year estimated in a recent report from the New York State Energy Research and Development Authority (NYSERDA 2003). We assumed that 7 percent of the dairy farms in New England outside of Vermont have 200 or more head. In Vermont, where dairy operations appear to be larger and more abundant than in the rest of New England, we assumed the figure to be 10 percent. We further assumed that the farms with greater than 200 head had an average of 350 head, which is the approximate herd size per farm in New York (New York Agricultural Statistics Service 2003). Finally, we assumed that 80 percent of the farms with greater than 200 head can actually install manure digesters in a CHP configuration. Using this methodology, we calculated the New England manure digestion resource potential to be 84.5 MWh per year from 70,420 cows by 2009.

[13] Obtained from Cantor Fitzgerald Market Price Index, available at <http://www.emissionstrading.com/index_mpi.htm>.

Table 5.12 Manure Digestion Availability and Cost Assumptions

	2006	2009	2012	2015
Available Capacity (MW)	8	16	16	16
Available Energy (GWh)	42	84	84	84
Levelized Cost ($/MWh)	$58.7	$58.7	$58.7	$58.7

Table 5.13 Cost and Performance Assumptions for Manure Digestion

Capacity Factor	Capital Cost ($/kW)	Other Fixed Costs ($/kW)	O&M and Fuel Costs ($/MWh)
60%	$3,266	$(1,000)	$10.0

Note: The other fixed costs represent an estimate to account for the avoided capital cost of the thermal production from the CHP system and the cost of addressing environmental and odor problems which often drive manure digestion development (NYDPS 2003).

Other Biomass Technologies

We have excluded from our analysis certain biomass technologies that we believe will not be cost effective contributors to any of the renewable energy standards in New England. These include biomass gasification, direct biomass combustion, and repowering of coal plants to burn biomass. We do not expect the costs of these technologies to be competitive with other renewable resources during our study period.

5.3 Landfill Gas

Landfill gas to energy is a relatively low cost resource that relies on a "mature" technology. Thus, it is expected to play a significant role in meeting generation requirements in the early years of the New England renewable energy standards until the available resource is exhausted. We have adopted the major cost, performance, and availability assumptions of the Massachusetts RPS cost study. This study divides landfill gas projects into two size categories and assumes that the smaller projects carry a cost premium of $10/MWh in 2006 and $5/MWh thereafter.

Table 5.14 Landfill Gas Resource Availability and Cost Assumptions

	2006	2009	2012	2015
Large Landfill Gas				
Available Capacity (MW)	118	121	124	124
Available Energy (GWh)	930	954	978	978
Levelized Cost ($/MWh)	$45.0	$43.9	$41.8	$41.8
Small Landfill Gas				
Available Capacity (MW)	93	97	100	100
Available Energy (GWh)	733	765	788	788
Levelized Cost ($/MWh)	$53.9	$47.8	$46.8	$46.8

Table 5.15 Cost and Performance Assumptions for Landfill Gas

Year	Capacity Factor	Capital Cost ($/kW)	Variable O&M ($/MWh)	Other Costs ($/MWh)
Large Landfill Gas	0.90	$1,727	$15.0	–
Small Landfill Gas	0.90	$1,727	$15.0	$10.0 in 2006, $5.0 after

5.4 Wind

Specific Wind

A number of wind development projects in New England are currently in the planning or proposal stages. The authors of the Massachusetts RPS cost study interviewed project developers to obtain estimates of the potential and cost of these projects. For simplification, we have grouped all of these projects into a single category, using a weighted average cost and aggregated the potential capacities of the individual projects.

Table 5.16 Specific Wind Resource Availability and Cost Assumptions

	2006	2009	2012	2015
Available Capacity (MW)	225	225	225	225
Available Energy (GWh)	591	591	591	591
Levelized Cost ($/MWh)	$53.4	$53.4	$53.4	$53.4

We assume that the current production tax credit (1.8 ¢/kWh) will be available for those wind projects that are installed by 2006, but not for those installed in later years. All of the specific wind projects are installed by 2006 and thus benefit from this subsidy.

Generic Wind

In addition to the specific wind projects underway, we assume that there is the potential for additional wind development in New England. Our assumptions regarding these "generic" wind projects are primarily based on the Massachusetts RPS cost study, and are presented in the following tables. These generic wind estimates only include land-based wind projects.

Table 5.17 Generic Wind Resource Availability and Cost Assumptions

	2009	2012	2015
Available Capacity (MW)	129	310	600
Available Energy (GWh)	345	842	1,682
Levelized Cost ($/MWh)	$64.5	$61.6	$58.0

We assume that the current production tax credit (1.8 ¢/kWh) will be available for those wind projects that are installed by 2006, but not for those installed in later years. However, none of the generic wind is assumed to be installed by 2006, and thus do not benefit from this subsidy.

Table 5.18 Cost and Performance Assumptions for Generic Wind

Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
2009	0.31	$812	$17.0	$5.0
2012	0.31	$772	$17.0	$5.0
2015	0.32	$733	$17.0	$5.0

Offshore Wind

The offshore wind resource potential in New England is large, but the technology has yet to be implemented in the United States. Although offshore wind parks require higher capital investment than land-borne wind projects, these costs can be offset by the higher capacity factors that are obtainable offshore. The 420-megawatt Cape Wind project, which would be the first offshore wind park in the country, may come online in 2005 if its developers successfully clear the regulatory and legal challenges facing the project.

We have adopted cost and performance assumptions from the Massachusetts RPS cost update study. We have assumed a 50 percent fixed operation and maintenance cost premium over generic wind, which is roughly consistent with the offshore wind assumptions from the OEI study.

Table 5.19 Offshore Wind Resource Availability and Cost Assumptions

	2006	2009	2012	2015
Available Capacity (MW)	200	600	1,000	1,500
Available Energy (GWh)	683	2,102	3,592	5,453
Levelized Cost ($/MWh)	$66.2	$79.1	$75.4	$73.3

We assume that the current production tax credit (1.8 ¢/kWh) will be available for those wind projects that are installed by 2006, but not for those installed in later years. This is why the 2006 wind costs are so much lower than in later years.

Table 5.20 Cost and Performance Assumptions for Offshore Wind

Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)
2006	0.39	1,587	$25.5	$5.0
2009	0.40	1,504	$25.5	$5.0
2012	0.41	1,454	$25.5	$5.0
2015	0.42	1,420	$25.5	$5.0

Québec Wind

The technical potential for wind development in Quebec is considerable. A study by the Canada Centre for Mineral Energy Technology estimated the technical potential in the province to be nearly 10,000 MW (CANMET 1992). However, the amount of wind that will actually be developed in the next 10 to 15 years is likely far less, and the portion of the developed wind energy that is available for export to New England is even more difficult to estimate. We have adopted the assumptions about the availability and cost of Quebec wind from the New York RPS and Massachusetts RPS studies. These assumptions are summarized in Tables x and x.

The amount of Quebec wind that will actually be used to meet New England RPS demand will be constrained by the cost premium incurred in transmitting the generation from an intermittent resource. We have assumed that the Quebec wind generation that is imported into New England will incur an import premium of $8.00/MWh and experience line losses of 4 percent (Grace et. al. 2002).

Table 5.21 Quebec Wind Resource Availability and Cost Assumptions

	2006	2009	2012	2015
Available Capacity (MW)	250	400	580	750
Available Energy (GWh)	723	1,156	1,677	2,168
Levelized Cost ($/MWh)	$74.0	$71.1	$68.2	$64.8

Table 5.22 Cost and Performance Assumptions for Quebec Wind

Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Import Premium ($/MWh)
2006	0.33	1,010	$17.0	$5.0	$8.0
2009	0.33	944	$17.0	$5.0	$8.0
2012	0.33	878	$17.0	$5.0	$8.0
2015	0.33	800	$17.0	$5.0	$8.0

5.5 Imports From New York

The amount of renewable generation that is imported from New York to meet New England RPS demand is dependent on technical and economic transmission constraints and the cost premium of the new renewables developed in New York. If the trading price of renewable credits in New York is considerably lower than the price of RECs in the New England GIS, then one would expect significant imports of lower-priced renewable generation into New England.

The New York RPS study assumes that 25 percent of the New England RPS demand (exclusive of Vermont) will be met by New York renewable imports (NYDPS 2003). This assumption is based on the expectation that New York renewable energy credits will be lower cost than New England's. Instead of assuming a predetermined quantity of New York renewable generation that is applied towards meeting New England's RPS demand, we have modeled New York renewable imports in a similar way to the other resources in our analysis. We have assumed that 25 percent of New England's renewable potential (exclusive of Vermont) can be *potentially* met by New York imports, subject to cost. By this method, the amount of generation that is actually imported from New York will depend upon the marginal price at which New England's renewable demand intersects the supply curve.

We assumed that the base cost of New York renewable imports would equal the RPS cost premium in any given year from the results of the New York RPS study. Consistent with our methodology for analyzing other resources, we have divided New York imports into three tiers of various costs. As in the Massachusetts RPS cost sensitivity analysis, these cost tiers are determined by applying a range of outwheeling costs and locational marginal price (LMP) premiums to the base premium price of New York renewable generation. Table x summarizes the cost and availability assumptions of renewable imports from New York.

Table 5.23 New York Imports Availability and Cost Assumptions

	2006	2009	2012	2015
Available Energy (GWh)	509	1084	1677	2216
Levelized Cost	$60.4	$62.3	$67.7	$71.4

Table 5.24 Assumed Cost Adders for New York Imports

	Outwheeling Cost ($/MWh)	Locational Price Adder ($/MWh)
Low	$0.0	$2.0
Average	$6.0	$2.0
High	$7.5	$2.5

5.6 Solar

While there is likely to be some development of rooftop photovoltaics systems in New England that are eligible for the Vermont RPS, these resources are likely to be much more expensive than other renewables, and to be developed for niche applications only. We do not expect them to play a significant role in setting the renewable premium or affecting the RPS costs. Consequently, we have left solar resources out of our analysis for simplification purposes.

5.7 Assumptions Regarding the Range of Cost Estimates

All of the cost and operating assumptions discussed in this section involve some amount of uncertainty and unpredictability. We have accounted for this by assuming three levels of costs and availabilities for each of the resource types. For each renewable resource type discussed above we assume a low, medium and high level of cost and availability. This methodology and our assumptions regarding the three levels are based on the Massachusetts RPS studies. (Grace et. al. 2002, Smith et. al. 2000)

This approach provides a more detailed supply curve, and allows for greater opportunities for a low-cost version of one type of renewable to displace a high-cost version of another type. The results provided in Section 6 present an aggregated result for all of the three levels for each resource type.

5.8 Interconnection Costs

Our cost analysis includes interconnection costs for the renewable energy technologies. We adopted the interconnection costs used by EIA as inputs to NEMS (National Energy Modeling System). EIA assigns these costs by region. In New England, the interconnection cost per kilowatt is assumed to be $218/kW.

Wind technologies are assigned an additional interconnection cost to account for their increased distances from transmission lines. In New England, wind generators that are located within ten miles of existing transmission lines are assigned an additional interconnection cost of $38/kW. We have applied this cost adder to all wind facilities in New England and Quebec, whether offshore or land-based.

Interconnection costs were not included for biomass co-firing with fossil fuel and existing biomass plants. These plants will not require additional interconnection costs because they are already connected to the electricity grid.

We have not included interconnection costs in our estimate of future wholesale market prices in New England. Including interconnection costs in our estimate of the levelized generating cost of a new combined cycle natural gas plant would cause a significant increase in the wholesale price projection and reduce the premium cost of renewable generation. We have made this conservative assumption to avoid understating the cost impacts of the RPS, and to account for the possibility that interconnection costs can be minimized for a new combined cycle plant by siting it an existing plant site.

6 The Mix of Renewables Supplying the Vermont RPS

Some Renewables are Eligible Only in Vermont

Vermont allows more types of renewables to be eligible for the RPS than Massachusetts or Connecticut.[14] In particular, Vermont allows hydro facilities to be eligible as long as they are smaller than 80 MW. Vermont also allows more types of biomass to be eligible, including biomass/coal co-firing, expansion of existing biomass facilities, and anaerobic digestion of agricultural products.[15]

Our analysis suggests that these additional renewable resources are generally low-cost and are quite plentiful relative to the Vermont RPS demand. Thus, under the current RPS eligibility definitions in Vermont, we would expect that generation from hydro power and Vermont-eligible biomass (especially expansion of existing biomass facilities) to be sufficient to meet the *entire* Vermont RPS demand. We would also expect the renewable premiums and the RPS cost impacts to be quite low because these additional renewable resources cost little, or no, more than the New England wholesale electricity price.

In order to provide informative estimates of the potential costs of the Vermont RPS, we have prepared two sets of cost estimates.

- Vermont-Only RPS. This assumes that the Vermont RPS legislation remains unchanged, and will allow small hydropower and all types of biomass generation to be eligible. These renewable sources will cost significantly less than other renewables used to meet the renewable portfolio standards in other states. Therefore, the RECs from hydro and Vermont-eligible biomass projects will be traded separately from those of other renewables. In other words, there will be a separate REC market for these low-cost renewable types, and the supply curve for the Vermont RPS will be based on this market, not the market for RECs in Massachusetts and Connecticut.

- Vermont-Only RPS, Excluding Hydro-Québec. There is some uncertainty as to whether Hydro-Québec will be able to use its renewable generation to comply with the Vermont RPS. In order to do so, Hydro-Québec will first need to establish a system for creating and accounting for Renewable Energy Credits that is consistent with the New England Generation Information System. The hydro generation from Hydro-Québec plays an important role in the renewables mix in the Vermont-Only analysis. Thus, we have developed a set of cases to test the effect of excluding the Hydro-Québec small hydro generation from the Vermont-Only mix of renewables.

[14] The Connecticut RPS includes two classes, or tiers, of renewables. Class I includes solar, wind, fuel cells, methane gas from landfills, and sustainable biomass. Class II trash-to energy biomass, other biomass sources, and hydropower. Our analysis includes the Connecticut Class I renewables, but excludes the Class II renewables as a simplifying assumption. The Massachusetts RPS requires that biomass resources meet certain technology and emissions requirements, which essentially exclude expansion of exiting biomass facilities and co-firing at existing coal plants.

[15] The Vermont RPS also allows biomass generation from sewage treatment plant wastes. While this may be an important resource, we expect that the total energy available will be quite small. Consequently, we have not included it in this analysis.

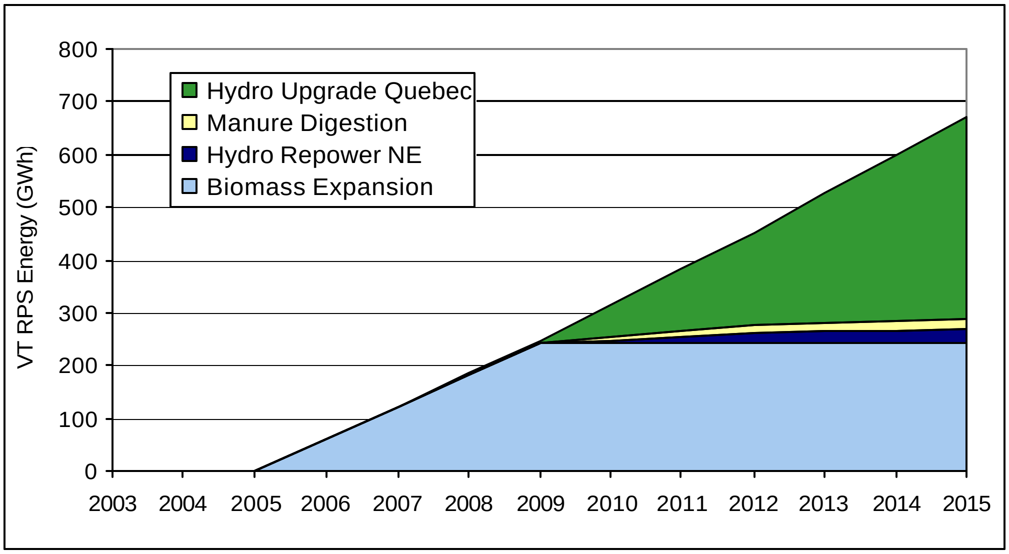
- New England RPS. This assumes that the Vermont RPS legislation will be modified to exclude those resources that are not eligible in Massachusetts and Connecticut.[16] Hydropower and certain biomass facilities will not be included in any of the three RPS states. Consequently, there will be a single REC market for the renewable portfolio standard in all three states, and the supply curve for the New England RPS will dictate the costs required to meet the Vermont RPS.

In the following sections we present the mix of renewable resources that are expected to supply these three types of renewable portfolio standards in Vermont. In Section 7, we present the cost results separately for these types of renewable portfolio standards.

The Mix of Renewables to Supply the Vermont-Only RPS

Figure 6.1 and Table 6.1 present a summary of the mix of resources expected to meet the Vermont RPS. This mix includes relatively low-cost generation from increased generation at existing biomass facilities, a small amount of repowering of existing hydro facilities in New England, a small amount of generation from manure digestion, and a considerable amount of generation from upgrades at small hydro facilities in Québec.

Figure 6.1 The Mix of Renewables Supplying the Vermont RPS



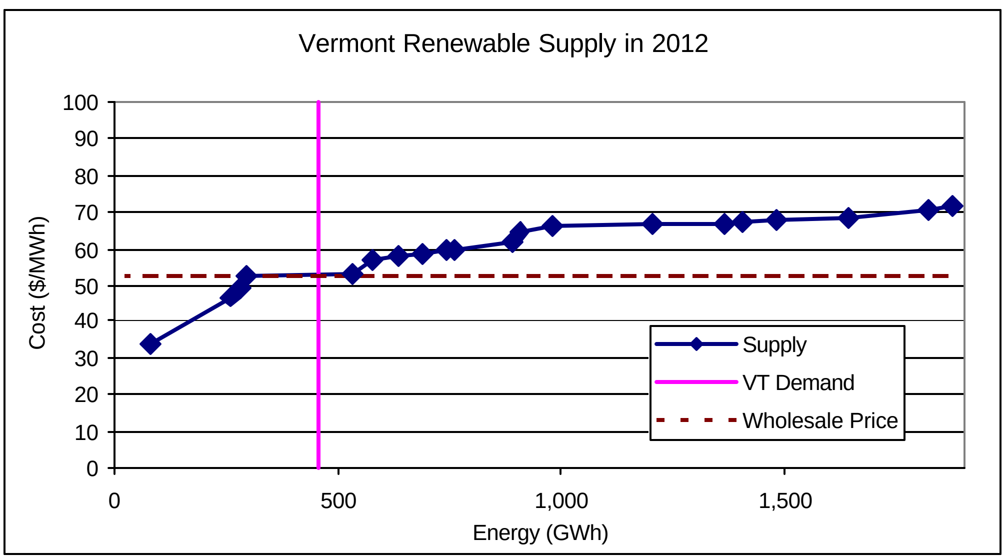
[16] Again, for Connecticut we are only including Class I renewables, where the biomass resources are limited to methane gas from landfills and sustainable biomass.

Table 6.1 Generation From the Vermont-Only Renewable Types (GWh)

Year	Bio-Cofire With Coal	Biomass Expansion	Hydro Repower NE	Hydro Upgrade Quebec	Manure Digestion
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	59	0	0	0
2007	0	120	0	2	0
2008	0	181	0	4	0
2009	0	241	0	6	0
2010	0	241	7	63	5
2011	0	241	13	120	10
2012	0	241	20	177	14
2013	0	241	23	247	15
2014	0	241	26	316	16
2015	0	241	29	385	17

Figure 6.2 presents the supply curve for the Vermont-Only RPS case, along with the RPS demand and the wholesale market price, for the year 2012. It shows that if the Vermont RPS demand is based on the one percent per year target, there will be enough renewable generation to meet that demand for less than the wholesale market price. However, the supply curve begins to gradually exceed the wholesale price after roughly 600 GWh of generation. If the Vermont RPS demand begins to exceed that level of generation in this year, then there will be small positive renewable premiums associated with that demand.

Figure 6.2 Supply Curve for the Vermont-Only RPS in 2012



The Mix of Renewables to Supply the Vermont-Only RPS, Excluding Hydro-Québec

Figure 6.3 and Table 6.2 present a summary of the mix of resources expected to meet the Vermont RPS if generation from Hydro-Québec is excluded from the mix. As indicated, the generation from Hydro-Québec hydropower is replaced with generation from: additional hydro repowering in New England, additional manure digestion, development of New England hydro at existing dams, and biomass co-firing at coal plants.

Figure 6.3 Mix of Renewables Supplying the Vermont-Only RPS, Excluding Hydro-Québec

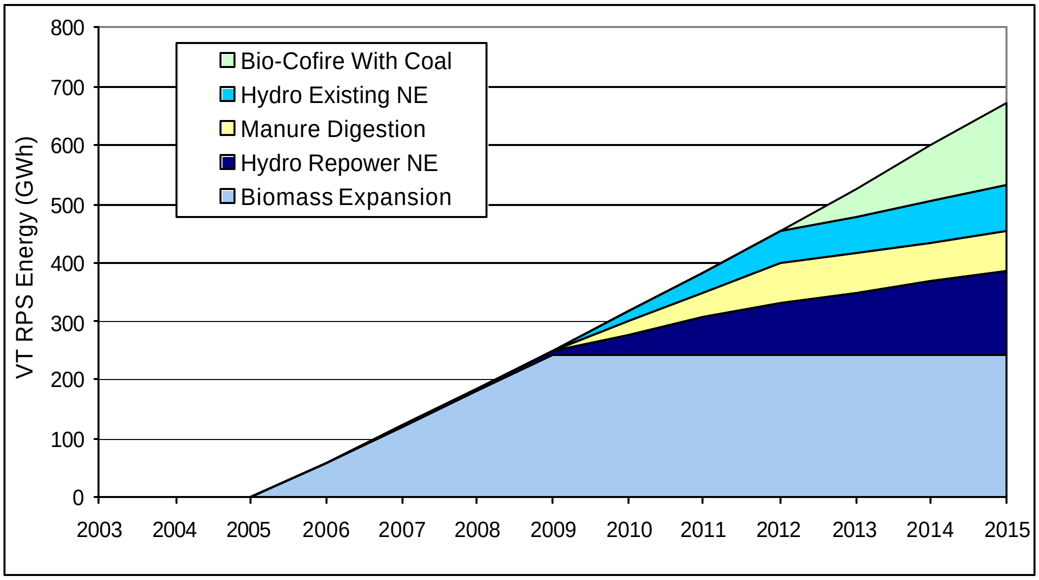


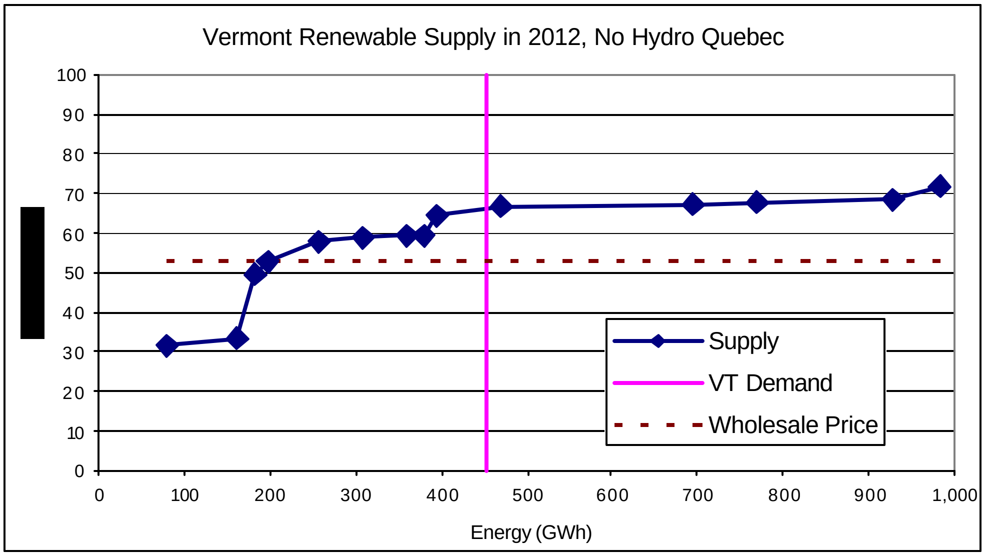
Table 6.2 Generation From the Renewables Supplying the Vermont-Only RPS, Excluding HQ (GWh)

Year	Bio-Cofire With Coal	Biomass Expansion	Hydro Existing NE	Hydro Repower NE	Manure Digestion
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	59	0	0	0
2007	0	120	0	2	0
2008	0	181	0	4	0
2009	0	241	0	6	0
2010	0	241	18	34	22
2011	0	241	35	63	45
2012	0	241	53	91	67
2013	46	241	62	109	67
2014	93	241	71	127	67
2015	139	241	80	144	67

Figure 6.4 presents the supply curve for the Vermont-Only RPS case excluding Hydro-Québec, along with the RPS demand and the wholesale market price, for the year 2012. It shows that in this case the intersection of the demand and supply curve is above the wholesale market prices.

The supply curve is relatively flat for generation levels above the Vermont demand, suggesting that modest changes to our renewables assumptions would be unlikely to significantly change the cost results.

Figure 6.4 Supply Curve for the Vermont-Only RPS in 2012, Excluding Hydro-Québec



The Mix of Renewables to Supply the New England RPS Demand

Figure 6.5 and Table 6.3 present a summary of the mix of resources expected to meet the New England RPS. Landfill gas represents a significant portion of the mix, especially in the early years. Wind generation also represents a large portion of the mix, especially in later years. As a simplifying assumption, we have assumed that all of the new RPS demand between 2012 and 2015 will be met with generic and off-shore wind facilities.

Figure 6.5 Mix of Renewables Supplying the New England RPS

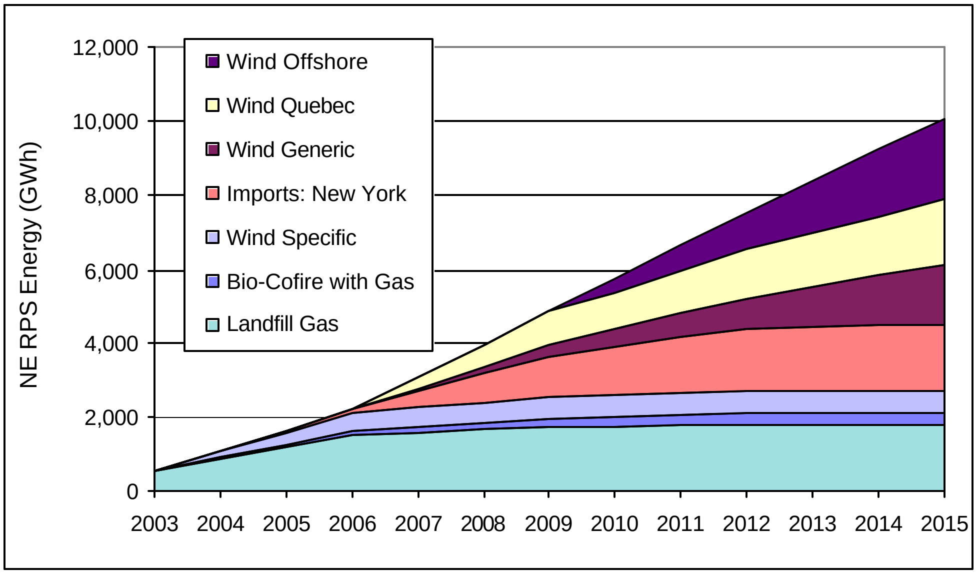
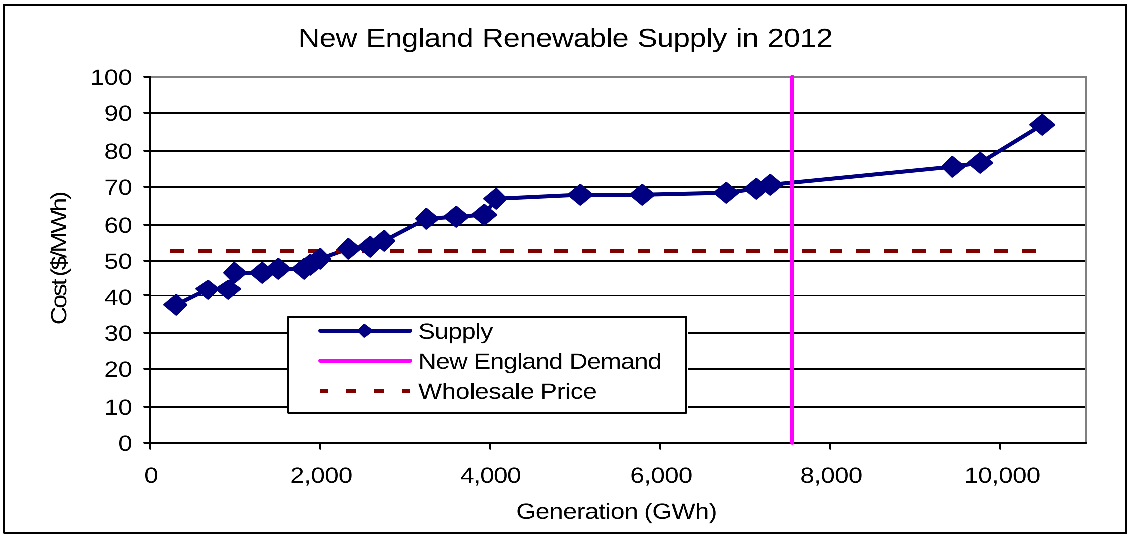


Table 6.3 Generation From the Renewables Supplying the NewEngland RPS (GWh)

Year	Bio-Cofire with Gas	Imports: New York	Landfill Gas	Wind Generic	Wind Offshore	Wind Quebec	Wind Specific
2003	0	0	534	0	0	0	0
2004	38	34	858	0	0	0	158
2005	75	68	1,182	0	0	0	315
2006	113	102	1,505	0	0	0	473
2007	153	429	1,577	92	1	308	512
2008	193	757	1,648	184	1	617	552
2009	234	1,084	1,719	276	2	925	591
2010	271	1,282	1,734	465	333	1,064	591
2011	309	1,479	1,750	653	665	1,203	591
2012	347	1,677	1,766	842	996	1,341	591
2013	347	1,709	1,766	1,122	1,395	1,472	591
2014	347	1,741	1,766	1,402	1,793	1,603	591
2015	347	1,773	1,766	1,682	2,192	1,734	591

Figure 6.6 presents the supply curve for the New England RPS, along with the New England RPS demand and the wholesale market price, for the year 2012. In this case the intersection of the demand and supply curve is well above the wholesale market prices. Again, the supply curve is relatively flat in the region surround the New England level of demand, suggesting that modest changes to our renewables assumptions would be unlikely to significantly change the cost results.

Figure 6.6 Supply Curve for the Vermont-Only RPS in 2012, Excluding Hydro-Québec



7. Potential Cost Impacts of the VT RPS

7.1 Vermont Electricity Sales and Prices

Current retail electricity sales, prices and bills in Vermont are taken from the US Energy Information Administration (EIA 03/2003). In 2001 typical monthly electric bills for residential, commercial and industrial customers were $74, $427, and $25,669, respectively.[17]

Vermont electricity sales are assumed to increase in the future at the same growth rate as sales in New England (ISO-NE 04/2003). Vermont retail electricity prices and bills are assumed to increase in the future at half of the growth rate of the New England wholesale electricity prices, since the wholesale prices currently represent roughly half of the retail prices.

Table 7.1 Vermont Electricity Prices, Sales and Costs

Year	Average Retail Price ($/MWh)	Retail Electricity Sales (GWh)	Total Retail Electric Costs (mil$)
2003	112.36	5,701	641
2004	112.36	5,785	650
2005	115.10	5,858	674
2006	117.77	5,928	698
2007	120.38	6,005	723
2008	122.94	6,091	749
2009	125.45	6,181	775
2010	127.90	6,275	803
2011	128.22	6,373	817
2012	128.54	6,470	832
2013	128.87	6,554	845
2014	129.19	6,639	858
2015	129.51	6,724	871

7.2 Base Case: RPS Set at One Percent Per Year

Vermont-Only RPS

Our base case assumes that the Vermont RPS target will be one percent per year for ten years, beginning in 2006. All of the energy to meet this RPS target can be obtained from the relatively low-cost renewables that are not eligible for renewable portfolio standards in other New England

[17] Because Vermont has a relatively small number of industrial customers, the monthly bills appear to be skewed by some very large customers in Vermont. These average monthly industrial bills are substantially higher than any other state in New England. Therefore, the RPS bill impacts for industrial customers should used with caution.

states. The mix of renewables is presented in Figure 6.1 As a result, we find that, as currently structured, the Vermont RPS is unlikely to cause any increase in electricity costs.[18]

Small hydro power plants from Québec are expected to play a large role in providing power to the VT RPS, and these plants are one of the reasons that the RPS is expected to have such low costs under this scenario. There is some uncertainty as to whether Hydro Québec will be able to sell this power into New England as certified renewable energy. Thus, we have developed a set of cases to test the effect of excluding the Hydro-Québec small hydro generation. In this case, we find that the Hydro-Québec hydro generation is replaced with generation from manure digesters, hydro development in New England and biomass co-firing at coal plants in New England. The mix of renewable generation in this case is presented in figure 6.2

The results of this sensitivity are presented in Table 7.2 below. [19] From the marginal cost perspective, the RPS premium gradually increases to slightly higher that $10/MWh, and the percent increase in electric costs increase to just under one percent by 2015. From the average cost perspective, the cost impacts are considerably lower. Figure 7.1 presents these results graphically.

Table 7.2 Cost Impacts: 1% Target; VT-Only Renewables, Excluding Hydro-Québec

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	1.70	0.2	0.03%	0.04	0.0	0.00%
2008	3.41	0.6	0.08%	0.08	0.0	0.00%
2009	5.11	1.3	0.16%	0.12	0.0	0.00%
2010	6.48	2.0	0.25%	1.18	0.4	0.05%
2011	7.84	3.0	0.37%	2.25	0.9	0.11%
2012	9.21	4.2	0.50%	3.31	1.5	0.18%
2013	9.76	5.1	0.61%	3.65	1.9	0.23%
2014	10.31	6.2	0.72%	3.99	2.4	0.28%
2015	10.86	7.3	0.84%	4.33	2.9	0.33%

[18] Due to the uncertainty involved in this type of analysis, there may be some renewable resources contributing to the RPS whose costs exceed the wholesale market price, but if that occurs the costs impacts will be small.

[19] Unless otherwise noted, all costs in this report are presented in constant 2003-year dollars.

Figure 7.1 Cost Impacts: 1% Target; VT-Only Renewables, Excluding Hydro-Québec

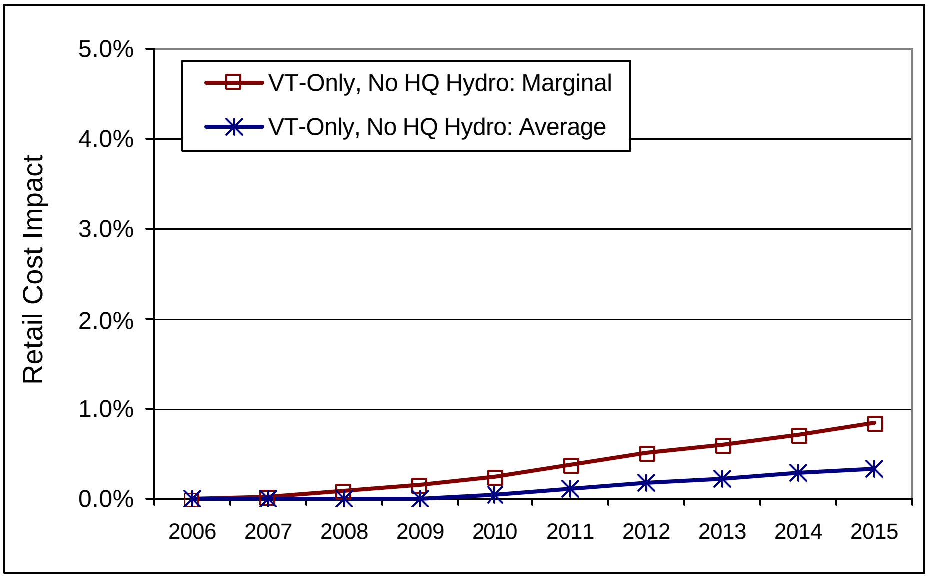


Table 7.3 presents the estimated impact on typical bills from this scenario. It shows that residential ratepayers are likely to see their bills increase by less than $1, commercial customers are likely to see their bills increase by roughly $1 to $4, and industrial customers to see bill increases ranging from roughly $100 to $250 by the end of the period. The industrial customer bill increases appear to be so large because the typical industrial customer bill in Vermont is currently over $25,000. Thus, a small percentage increase in the bill results in apparently large absolute increases.

Table 7.3 Bill Impacts: 1% Target; VT-Only Renewables, Excluding Hydro-Québec

	Marginal Renewable Cost Electric Bill Impacts: ($/month)			Average Renewable Cost Electric Bill Impacts: ($/month)		
Year	Typical Residential Customer	Typical Commercial Customer	Typical Industrial Customer	Typical Residential Customer	Typical Commercial Customer	Typical Industrial Customer
2006	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.02	0.13	8.10	0.00	0.00	0.19
2008	0.07	0.40	24.30	0.00	0.01	0.57
2009	0.14	0.81	48.61	0.00	0.02	1.13
2010	0.22	1.28	76.97	0.04	0.23	14.06
2011	0.32	1.86	111.82	0.09	0.53	32.04
2012	0.44	2.55	153.15	0.16	0.92	55.08
2013	0.54	3.08	185.54	0.20	1.15	69.39
2014	0.64	3.67	220.55	0.25	1.42	85.32
2015	0.75	4.29	258.19	0.30	1.71	102.85

New England RPS

Table 7.4 presents the cost impacts assuming that the RPS in Vermont is changed to exclude the Vermont-only resources (hydropower and some biomass). In this case, the RPS premiums are significantly higher than those for the Vermont-Only case, because it does not include some of the low-cost resources. Under the marginal cost approach, the renewable premiums range from roughly $14/MWh to $23/MWh, and the RPS would cause an increase in retail electric costs of roughly 1.5 percent by the later years of the study period. Under the average cost approach, the renewable premiums and the impacts on electric costs are roughly half of those based on the marginal approach. These results are presented graphically in Figure 7.2.

Table 7.4 Cost Impacts: 1% Target; New England RPS Perspective

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	13.65	0.8	0.1%	4.23	0.3	0.0%
2007	16.80	2.0	0.3%	5.39	0.6	0.1%
2008	19.95	3.6	0.5%	6.55	1.2	0.2%
2009	23.10	5.7	0.7%	7.71	1.9	0.2%
2010	22.88	7.2	0.9%	8.17	2.6	0.3%
2011	22.67	8.7	1.1%	8.63	3.3	0.4%
2012	22.46	10.2	1.2%	9.10	4.1	0.5%
2013	21.50	11.3	1.3%	9.04	4.7	0.6%
2014	20.53	12.3	1.4%	8.97	5.4	0.6%
2015	19.57	13.2	1.5%	8.91	6.0	0.7%

Figure 7.2 Cost Impacts: 1% Target; New England RPS Perspective

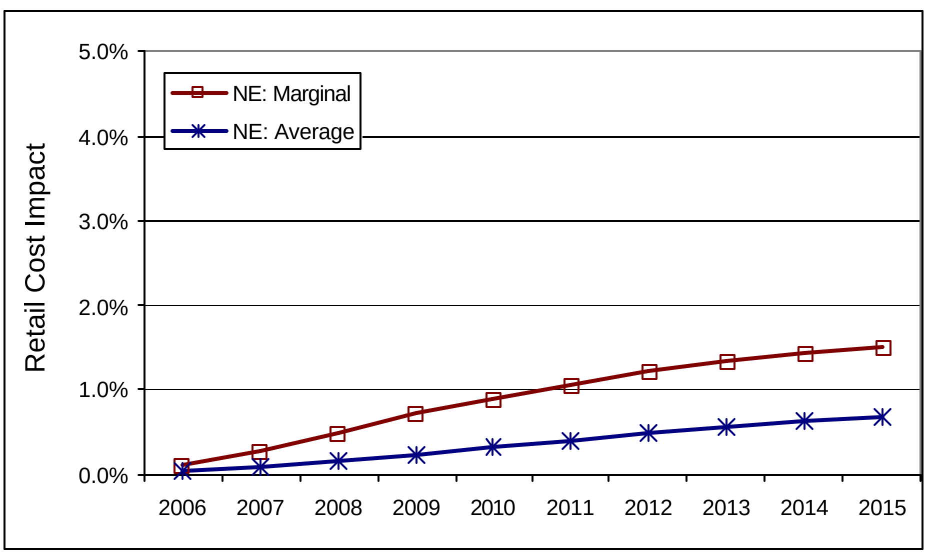


Table 7.5 presents the estimated impact on typical bills from this scenario. It shows that residential ratepayers are likely to see their bills increase by roughly $0.61 to $1.34, commercial customers are likely to see their bills increase by roughly $4 to $8, and industrial customers to see bill increases ranging from roughly $200 to $465 by the end of the period.

Table 7.5 Bill Impacts: 1% Target; New England RPS Perspective

	Marginal Renewable Cost Electric Bill Impacts: ($/month)			Average Renewable Cost Electric Bill Impacts: ($/month)		
Year	Typical Residential Customer	Typical Commercial Customer	Typical Industrial Customer	Typical Residential Customer	Typical Commercial Customer	Typical Industrial Customer
2006	0.09	0.54	32.43	0.03	0.17	10.06
2007	0.23	1.33	79.84	0.07	0.43	25.62
2008	0.41	2.36	142.23	0.13	0.78	46.69
2009	0.63	3.65	219.59	0.21	1.22	73.26
2010	0.79	4.52	271.96	0.28	1.61	97.08
2011	0.93	5.37	323.32	0.36	2.05	123.11
2012	1.08	6.21	373.67	0.44	2.52	151.34
2013	1.18	6.79	408.73	0.50	2.86	171.80
2014	1.27	7.30	439.21	0.55	3.19	191.98
2015	1.34	7.73	465.11	0.61	3.52	211.86

7.3 Low RPS Case: RPS Set at One-Half Percent Per Year

This sensitivity assumes that the Vermont RPS target is one-half percent per year. Here the RPS premiums are lower than in the Base Case, because a smaller RPS target requires less of the more expensive renewables. In addition, since the total RPS energy is smaller than in the Base Case, the RPS cost impact (in millions of dollars) will be smaller as well.

For the Vermont-only case, the renewable generators are again found to cost less than the wholesale market price, as would be expected. Consequently, there would be no increase in electricity costs in this case. For the Vermont-only case with Hydro-Québec hydro generation excluded, the cost impacts are quite small, as indicated in Table 7.6.

Table 7.6 Cost Impacts: 0.5% Target; VT-Only Renewables, Excluding Hydro-Québec

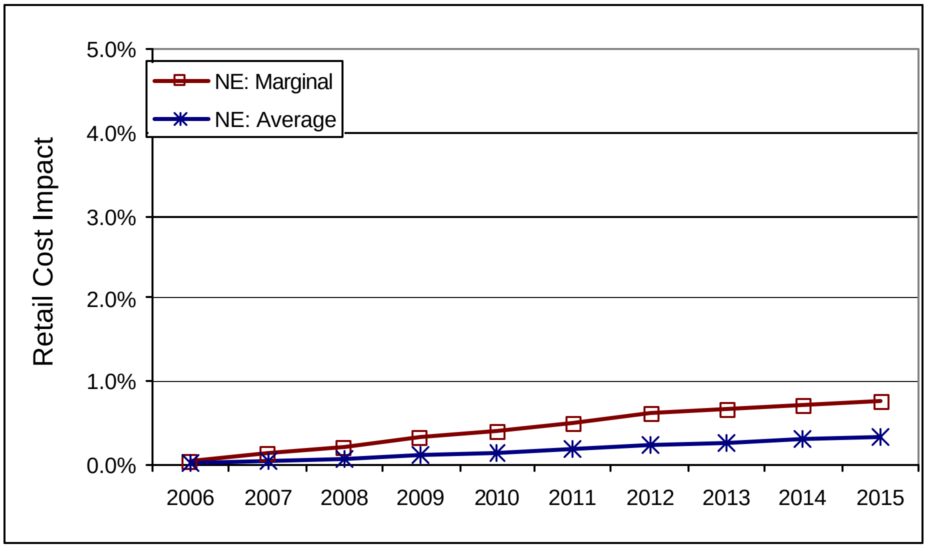
	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	0.00	0.0	0.00%	0.00	0.0	0.00%
2008	0.00	0.0	0.00%	0.00	0.0	0.00%
2009	0.00	0.0	0.00%	0.00	0.0	0.00%
2010	0.00	0.0	0.00%	0.00	0.0	0.00%
2011	0.00	0.0	0.00%	0.00	0.0	0.00%
2012	0.00	0.0	0.00%	0.00	0.0	0.00%
2013	1.69	0.4	0.05%	0.25	0.1	0.01%
2014	3.39	1.0	0.12%	0.49	0.1	0.02%
2015	5.08	1.7	0.20%	0.74	0.2	0.03%

Table 7.7 and Figure 7.3 present the results of the New England RPS case, where the Vermont-only renewables are excluded. Here the marginal-based premiums do not change, and the average based premiums only change slightly, relative to the 1% RPS case, because the Vermont RPS target will have a relatively small effect on the entire New England RPS market. The percent increase in retail electric costs, however, is roughly half of that in the 1% RPS case, because the renewable premium is applied to half as much energy.

Table 7.7 Cost Impacts: VT RPS at Half Percent; New England RPS Perspective

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	13.65	0.4	0.1%	4.10	0.1	0.0%
2007	15.99	1.0	0.1%	5.19	0.3	0.0%
2008	18.33	1.7	0.2%	6.28	0.6	0.1%
2009	20.67	2.6	0.3%	7.36	0.9	0.1%
2010	21.27	3.3	0.4%	7.80	1.2	0.2%
2011	21.86	4.2	0.5%	8.24	1.6	0.2%
2012	22.46	5.1	0.6%	8.68	2.0	0.2%
2013	21.50	5.6	0.7%	8.64	2.3	0.3%
2014	20.53	6.1	0.7%	8.59	2.6	0.3%
2015	19.57	6.6	0.8%	8.55	2.9	0.3%

Figure 7.3 Cost Impacts: VT RPS at Half Percent; New England RPS Perspective



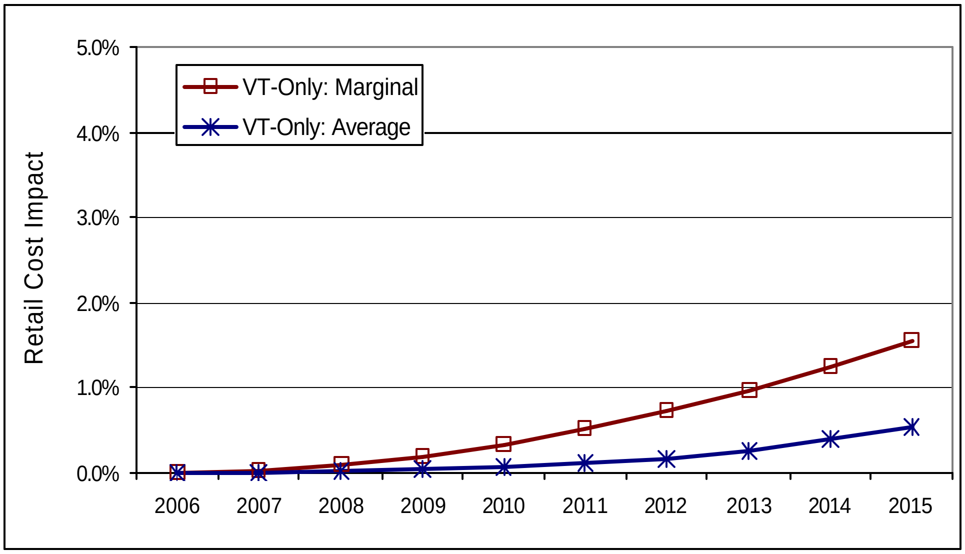
7.4 High RPS Case: RPS Set at Two Percent Per Year

The tables and figures below present the cost impacts of a Vermont RPS target of two percent per year. In the Vermont-Only case, the renewable premiums gradually increase to roughly \$3.5/MWh when based on average renewable costs, and to roughly \$10/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 0.5% and 1.5% by 2015, respectively.

Table 7.8 Cost Impacts: 2% Target; Vermont-Only Renewables

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium (\$/MWh)	RPS Premium Cost (million\$)	Percent of Retail Electric Costs	RPS Premium (\$/MWh)	RPS Premium Cost (M\$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	1.02	0.2	0.03%	0.27	0.1	0.01%
2008	2.04	0.7	0.10%	0.55	0.2	0.03%
2009	3.06	1.5	0.19%	0.82	0.4	0.05%
2010	4.27	2.7	0.33%	1.03	0.6	0.08%
2011	5.49	4.2	0.51%	1.23	0.9	0.12%
2012	6.70	6.1	0.73%	1.44	1.3	0.16%
2013	7.82	8.2	0.97%	2.11	2.2	0.26%
2014	8.94	10.7	1.25%	2.78	3.3	0.39%
2015	10.06	13.5	1.55%	3.45	4.6	0.53%

Figure 7.4 Cost Impacts: 2% Target; Vermont-Only Renewables

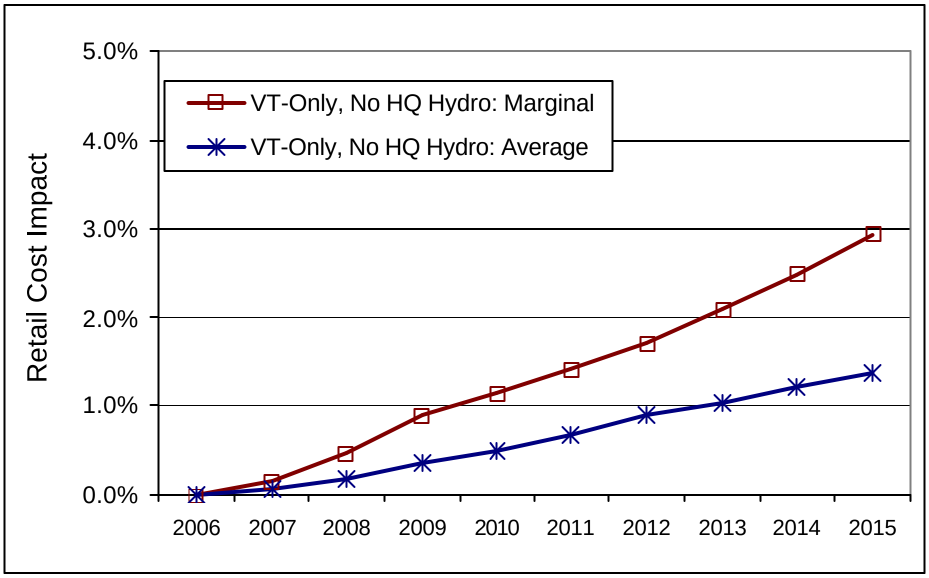


In the Vermont-only case excluding Hydro-Québec hydropower, the renewable premiums gradually increase to roughly $8.8/MWh when based on average renewable costs, and to roughly $19/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 1.4% and 3.0% by 2015, respectively. These cost impacts are considerably higher than in the base case (1% target), because the renewable premiums are higher and the amount of energy to which they are applied are twice as high.

Table 7.9 Cost Impacts: 2% Target; VT-Only Renewables, Excluding Hydro-Québec

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	4.72	1.1	0.16%	1.84	0.4	0.06%
2008	9.43	3.4	0.46%	3.68	1.3	0.18%
2009	14.15	7.0	0.90%	5.51	2.7	0.35%
2010	14.64	9.2	1.14%	6.40	4.0	0.50%
2011	15.13	11.6	1.42%	7.28	5.6	0.68%
2012	15.62	14.1	1.70%	8.16	7.4	0.89%
2013	16.74	17.5	2.08%	8.38	8.8	1.04%
2014	17.85	21.3	2.49%	8.61	10.3	1.20%
2015	18.97	25.5	2.93%	8.84	11.9	1.36%

Figure 7.5 Cost Impacts: 2% Target; VT-Only Renewables, Excluding Hydro-Québec

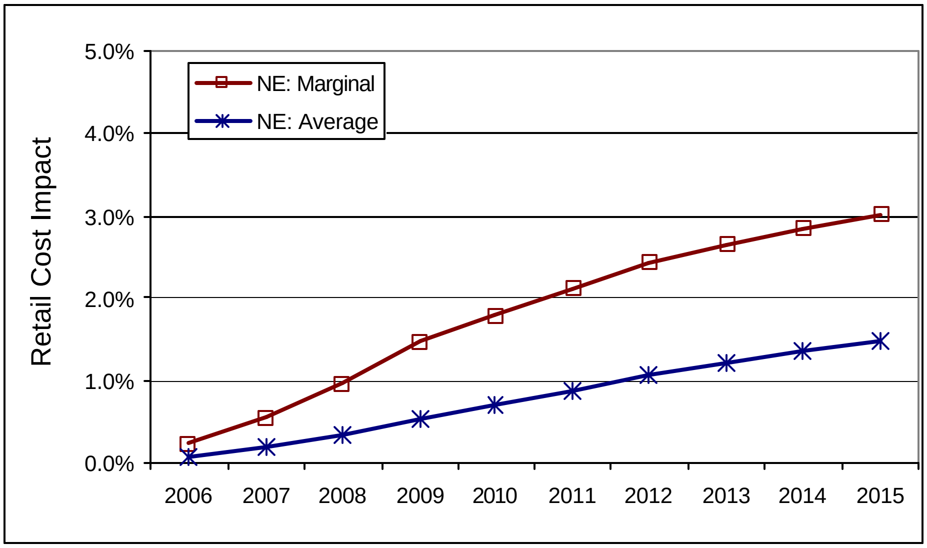


For the New England RPS case, the marginal RPS premium does not change from the base case, because the Vermont RPS has only a small impact on the overall New England RPS demand. Consequently, for the marginal case the total RPS costs and the electric bill impacts are twice those for the base case. In this case, the renewable premiums gradually increase to roughly $9.6/MWh when based on average renewable costs, and to roughly $20/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 1.5% and 3.0% by 2015, respectively.

Table 7.10 Cost Impacts: 2% Target; New England RPS Perspective

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	13.65	1.6	0.2%	4.48	0.5	0.1%
2007	16.80	4.0	0.6%	5.80	1.4	0.2%
2008	19.95	7.3	1.0%	7.13	2.6	0.3%
2009	23.10	11.4	1.5%	8.46	4.2	0.5%
2010	22.88	14.4	1.8%	8.92	5.6	0.7%
2011	22.67	17.3	2.1%	9.39	7.2	0.9%
2012	22.46	20.3	2.4%	9.85	8.9	1.1%
2013	21.50	22.5	2.7%	9.76	10.2	1.2%
2014	20.53	24.5	2.9%	9.67	11.6	1.3%
2015	19.57	26.3	3.0%	9.58	12.9	1.5%

Figure 7.6 Cost Impacts: 2% Target; New England RPS Perspective



7.5 Sensitivity To New England Wholesale Electricity Prices

We have conducted one set of sensitivities to test how our results would change with different forecasts of wholesale electricity prices. While there are several components of the wholesale electricity price that could be higher or lower than our base case, we make the simple assumptions that the wholesale prices would be 20 percent higher in all years for the High Wholesale Price sensitivity and 20 percent lower in all years for the Low Wholesale Price sensitivity. The resulting wholesale market prices are presented in Table 7.11 below. All of our sensitivities are relative to the Base Case assumption of a one percent RPS target in Vermont.

Table 7.11 Wholesale Market Prices in the Base Case and Sensitivities ($/MWh)

Year	Low Case	Base Case	High Case
2004	32.46	40.58	48.70
2005	34.04	42.56	51.07
2006	35.63	44.53	53.44
2007	37.21	46.51	55.81
2008	38.79	48.48	58.18
2009	40.37	50.46	60.55
2010	41.95	52.44	62.92
2011	42.16	52.70	63.24
2012	42.37	52.96	63.56
2013	42.58	53.23	63.87
2014	42.79	53.49	64.19
2015	43.01	53.76	64.51

Low Wholesale Prices Sensitivity

The tables below present the results of the Low Wholesale Price Sensitivity. For the Vermont-Only case, the renewable premiums are now positive in all years. The impact on retail electric rates is still relatively low, reaching a roughly 0.4 percent increase by 2015 for the average approach, and roughly 0.8 percent increase for the marginal approach.

Table 7.12 Cost Impacts: 1% Target; Vermont-Only Renewables – Low Wholesale Prices

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	2.06	0.2	0.03%	0.05	0.0	0.00%
2008	4.13	0.8	0.10%	0.10	0.0	0.00%
2009	6.19	1.5	0.20%	0.14	0.0	0.00%
2010	7.61	2.4	0.30%	0.86	0.3	0.03%
2011	9.03	3.5	0.42%	1.57	0.6	0.07%
2012	10.45	4.7	0.57%	2.29	1.0	0.12%
2013	10.47	5.5	0.65%	3.10	1.6	0.19%
2014	10.49	6.3	0.73%	3.91	2.3	0.27%
2015	10.51	7.1	0.81%	4.72	3.2	0.36%

In the Vermont-only case excluding Hydro-Québec hydropower, the renewable premiums gradually increase to roughly $11/MWh when based on average renewable costs, and to roughly $21/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 0.9% and 1.7% by 2015, respectively.

Table 7.13 Cost Impacts: 1% Target; VT-Only, Excluding HQ – Low Wholesale Prices

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (M$)	Percent of Retail Electric Costs
2006	0.00	0.0	0.00%	0.00	0.0	0.00%
2007	4.67	0.6	0.08%	0.11	0.0	0.00%
2008	9.35	1.7	0.23%	0.22	0.0	0.01%
2009	14.02	3.5	0.45%	0.33	0.1	0.01%
2010	15.78	5.0	0.62%	2.88	0.9	0.11%
2011	17.54	6.7	0.82%	5.43	2.1	0.25%
2012	19.30	8.7	1.05%	7.99	3.6	0.43%
2013	20.02	10.5	1.24%	8.98	4.7	0.56%
2014	20.74	12.4	1.44%	9.98	6.0	0.69%
2015	21.46	14.4	1.66%	10.97	7.4	0.85%

In the New England RPS case, the renewable premiums gradually increase to roughly $18/MWh when based on average renewable costs, and to roughly $30/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 1.4% and 2.3% by 2015, respectively.

Table 7.14 Cost Impacts: 1% Target; New England RPS Perspective – Low Wholesale Prices

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	22.55	1.3	0.2%	11.47	0.7	0.1%
2007	26.10	3.1	0.4%	12.82	1.5	0.2%
2008	29.64	5.4	0.7%	14.18	2.6	0.3%
2009	33.19	8.2	1.1%	15.53	3.8	0.5%
2010	33.14	10.4	1.3%	16.19	5.1	0.6%
2011	33.10	12.7	1.5%	16.84	6.4	0.8%
2012	33.05	15.0	1.8%	17.50	7.9	1.0%
2013	32.14	16.9	2.0%	17.61	9.2	1.1%
2014	31.23	18.7	2.2%	17.73	10.6	1.2%
2015	30.32	20.4	2.3%	17.84	12.0	1.4%

High Wholesale Price Sensitivity

In the sensitivities with high wholesale prices, the renewable premiums are correspondingly lower than in the base case. Thus, for the Vermont-Only case, the renewable resources are still less than the wholesale market prices, and the cost impacts of this case are expected to be zero or negligible.

In the Vermont-only case excluding Hydro-Québec hydropower, the renewable premiums are zero all the way through to 2013, at which point they gradually increase to roughly $0.03/MWh when based on average renewable costs, and to roughly $0.27/MWh when based on marginal renewable costs. These premiums result in negligible increases in Vermont retail electric costs.

Table 7.15 presents the results for the New England RPS case. Here the renewable premiums gradually increase to roughly $2/MWh when based on average renewable costs, and to roughly $9/MWh when based on marginal renewable costs. These premiums result in Vermont retail electric cost increases of roughly 0.2% and 0.7% by 2015, respectively.

Table 7.15 Cost Impacts: 1% Target; New England RPS Perspective – High Wholesale Prices

	Marginal Renewable Cost			Average Renewable Cost		
Year	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs	RPS Premium ($/MWh)	RPS Premium Cost (million$)	Percent of Retail Electric Costs
2006	4.74	0.3	0.0%	0.24	0.0	0.0%
2007	7.49	0.9	0.1%	1.01	0.1	0.0%
2008	10.25	1.9	0.3%	1.78	0.3	0.0%
2009	13.00	3.2	0.4%	2.55	0.6	0.1%
2010	12.63	4.0	0.5%	2.54	0.8	0.1%
2011	12.25	4.7	0.6%	2.52	1.0	0.1%
2012	11.87	5.4	0.6%	2.51	1.1	0.1%
2013	10.85	5.7	0.7%	2.40	1.3	0.1%
2014	9.83	5.9	0.7%	2.30	1.4	0.2%
2015	8.82	5.9	0.7%	2.20	1.5	0.2%

8. Summary of Results

Our analyses suggest that the Vermont RPS as currently designed will have very small impacts on Vermont retail electricity costs – if it has any impact at all. If the RPS target were set at one percent per year, increasing to 10 percent by 2015, the costs would be negligible. The Vermont RPS target could be as high as two percent per year, increasing to 20 percent by 2015, and the impact on retail costs would still be only 1.5 percent by that year.

If Hydro-Québec is unable to use its generation to supply the Vermont RPS, then the renewable premiums will be noticeably higher, but costs of the VT RPS will still be quite low. If Hydro-Québec is excluded from our base case, with an RPS target of one percent per year, the increase in retail electric costs is expected to be less than one percent by 2015.

If the Vermont RPS is modified to include only those renewables that are eligible in the Massachusetts and Connecticut renewable portfolio standards, then the renewable premiums will be higher still. However, even these renewable premiums will result in relatively moderate impacts on Vermont retail electric costs. Assuming an RPS target of one percent per year, the modified Vermont RPS would increase retail electric costs in 2015 by roughly 0.7 percent to 1.5 percent, depending upon whether the premiums turn out to be based on the average or the marginal costs.

The future wholesale market price in New England will have a large impact on the eventual cost impacts of the Vermont RPS. If the wholesale market prices turn out to be 20 percent lower than our forecast (which would make them lower than today's prices), then the Vermont-only RPS would still have a small cost impact, remaining under one percent by 2015. If Hydro-Québec generation is excluded, then the cost impact would still be less than two percent of retail costs by 2015. From the New England RPS perspective, the Vermont retail cost impact would reach a peak of 2.3 percent by 2015.

If the wholesale prices turn out to be 20 percent higher than our forecast, then the cost impacts of all the scenarios would be reduced considerably. Even from the New England RPS perspective, the Vermont retail electric costs would not increase by more than 0.7 percent.

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Appendix A

§ 8004. RENEWABLE PORTFOLIO STANDARDS FOR SALES OF ELECTRIC ENERGY

(a) The public service board shall design a proposed renewable portfolio standard in the form of draft legislation. The standard shall be developed with the aid of a renewable portfolio standard collaborative. The renewable portfolio standard collaborative, composed of representatives from the electric utilities, industry, renewable energy industry, ratepayers, environmental and consumer groups, the department of public service, and other stakeholders identified by the board, shall aid in the development of a renewable portfolio standard for renewable energy resources, as well as requirements for implementation of and compliance with that standard. The proposed renewable portfolio standard shall be applicable to all providers of electricity to retail consumers in this state. The proposed renewable portfolio standard developed by the board will be presented to the house committee on commerce, the house and senate committees on natural resources and energy, and the senate committee on finance in the form of draft legislation for consideration in January 2004.

(b) In developing the renewable portfolio standard, the board shall consider the following goals, which shall be afforded equal weight in formulating the standard:

(1) increase the use of renewable energy in Vermont in order to capture the benefits of renewable energy generation for Vermont ratepayers and citizens.

(2) maintain or reduce the rates of electricity being paid by Vermont ratepayers and lessen the price risk and volatility for future ratepayers.

§ 8002. DEFINITIONS

For purposes of this chapter:

[...]

(2) “Renewable energy” means energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate.

(A) For purposes of this subdivision (2), methane gas and other flammable gases produced by the decay of sewage treatment plant wastes or landfill wastes and anaerobic digestion of agricultural products, byproducts, or wastes shall be considered renewable energy resources, but no form of solid waste, other than agricultural or silvicultural waste, shall be considered renewable.

(B) For purposes of this subdivision (2), no form of nuclear fuel shall be considered renewable.

(C) For purposes of this chapter, the only energy produced by a hydroelectric facility to be considered renewable shall be from a hydroelectric facility with a generating capacity of 80 megawatts or less.