The Deerfield Wind Project:

Assessment of the Need for Power and the Economic and Environmental Attributes of the Project

Prepared for:
Deerfield Wind LLC.
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I. Introduction

This work was undertaken at the request of Deerfield Wind LLC, to forecast the need for, and benefits of, the proposed Deerfield Wind project ("the Project") for Vermont and the broader region. In particular, we examine project benefits in the following areas:

1. Long-term power supply needs in Vermont and New England;
2. Requirements for renewable sources of electricity in Vermont and New England;
3. Regional air quality, overall air emissions, and economic benefits of reduced air emissions from the electric generation sector.

In addition, we have made a preliminary assessment of the levelized cost of the project based on publicly available data, and we review the anticipated sources of revenue to suggest whether or not the project is likely to be economically viable.

We conclude that the Deerfield project would provide a clean, reliable source of power, with long-term cost stability, in a region in which the availability of cost-stable resources is quickly diminishing. We find that the project would offer significant air quality and reduced emissions benefits to the region by reducing dependence on fossil fuel combustion, and we value these benefits at between $0.6 million and $1.2 million per year. Finally, we find that the economics of the project appear sound based on projections of both project costs and the value of the project's output.

II. Benefits as a Source of Renewable Energy

Deerfield addresses Vermont's long-term power supply needs

Approximately 35% of the electric power consumed in Vermont (and 70% of in-state production) comes from a single source: the Vermont Yankee nuclear generating station, owned by Entergy Nuclear Vermont Yankee LLC[1] ("Entergy"). Vermont Yankee began operation in 1973, and the original operating license expires on March 21, 2012. The power purchase agreement (PPA) between Vermont utilities and Entergy terminates upon the expiration of this original license. Entergy has announced plans to apply for a 20-year license renewal, and experience in the industry suggests that they will be successful. At that point, the power will be available for sale throughout NEPOOL and beyond at market prices; there will no longer be any guarantee that the plant will represent long-term price stability as a source of power for Vermont consumers.

Another third of Vermont's electricity supply is imported under long-term contracts from Hydro Quebec. These contracts will begin to expire in 2015. As with the Yankee plant, this energy source may remain available, although probably at a diminished level as more of the power is retained to satisfy Quebec's own energy requirements. Vermont ratepayers will have no particular claim on the remaining output, which will be sold at market rates anywhere in the northeast United States or eastern Canada.

[1] http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/vermontyankee.html.

The termination of these long term contracts means that two-thirds of Vermont's power supply, now shielded from market price volatility, will become available only at market rates, if at all, and subject to competition from other purchasers (Figure 1). Because market prices in New England are set by fossil fuel sources such as natural gas-burning combined cycle plants, they are sensitive to fuel price volatility and emissions costs, including the anticipated cost associated with future CO_2 emissions regulation.

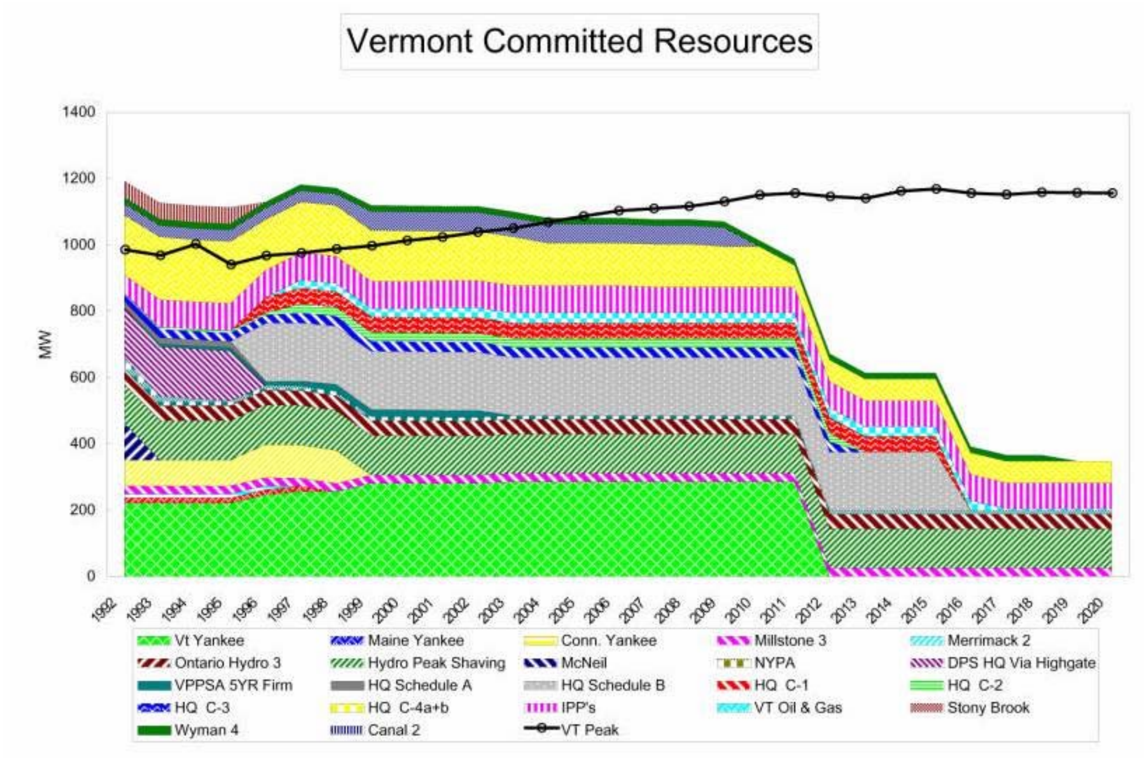

Figure 1: Committed electric supply resources in Vermont. From Vermont DPS *2005 Vermont Electric Plan.*

This loss of committed resources does not necessarily mean that Vermont is facing an impending *physical* shortage of capacity. There is currently a surplus of generating capacity in New England relative to load, at least outside of specific transmission-constrained areas such as Boston and southwestern Connecticut. What it does mean is that Vermont utilities are poorly hedged against both high prices and price volatility in electricity markets beginning in 2012. This puts pressure on Vermont utilities to obtain new long-term sources of supply which will not be affected by fluctuations in fuel or emissions costs. According to the 2005 Vermont Electric Plan:[2]

> Major challenges ahead include the replacement of major power source contracts representing roughly two-thirds of the Vermont energy mix in the period from 2012 and 2015. Many individual Vermont electric utilities face major resource decisions even sooner. Steps taken today by the State, Vermont utilities, and other stakeholders today will create opportunities for addressing tomorrow's challenges.

[2] Vermont Department of Public Service, *2005 Vermont Electric Plan*, available at http://publicservice.vermont.gov/pub/state-plans/state-plan-electric2005.pdf.

The Deerfield wind project would represent a long-term source of power for the region, generating enough energy to supply the total requirements of up to 20,000 Vermont homes.[3] This energy source would be insulated from volatile fossil fuel prices and from escalating emissions costs. In fact, in June of 2005 the Vermont General Assembly adopted renewable energy goals that specifically support this objective, as follows:[4]

> The general assembly finds it in the interest of the people of the state to promote the state energy policy established in section 202a of this title by:
>
> (1) Balancing the benefits, lifetime costs, and rates of the state's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the state flow to the Vermont economy in general, and to the rate paying citizens of the state in particular.
>
> (2) Supporting development of renewable energy and related planned energy industries in Vermont, in particular, while retaining and supporting existing renewable energy infrastructure.
>
> (3) Providing an incentive for the state's retail electricity providers to enter into affordable, long-term, stably priced renewable energy contracts that mitigate market price fluctuation for Vermonters.
>
> (4) Developing viable markets for renewable energy and energy efficiency projects.
>
> (5) Protecting and promoting air and water quality by means of renewable energy programs.
>
> (6) Contributing to reductions in global climate change and anticipating the impacts on the state's economy that might be caused by federal regulation designed to attain those reductions.

We conclude that the Deerfield project would provide substantial benefit to Vermont's resource base as a fixed-cost source of renewable energy, consistent with prudent procurement practice and with the specific goals of the Vermont General Assembly.

Deerfield addresses regional demand for renewable energy

A large number of states in the northeast and across the United States are implementing policies to encourage the development of renewable energy such as wind, solar, and biomass-fueled generation. Twenty states, plus Washington, D.C., have implemented Renewable Portfolio Standards (RPS) that require utilities to purchase a certain percentage of their energy from renewable sources. In the New England region, four states (Connecticut, Maine, Massachusetts, and Rhode Island) have adopted RPS.

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[3] Assuming 45 MW total capacity, a 36% capacity factor, and annual average household consumption of 7,142 kWh per U.S. Department of Energy estimate: http://www.eia.doe.gov/emeu/reps/enduse/er01_new-eng_tab1.html.

[4] No. 61. An Act Relating to Renewable Energy, Efficiency, Transmission, and Vermont's Energy Future (S.52), available at http://www.dsireusa.org/documents/Incentives/VT04R.doc

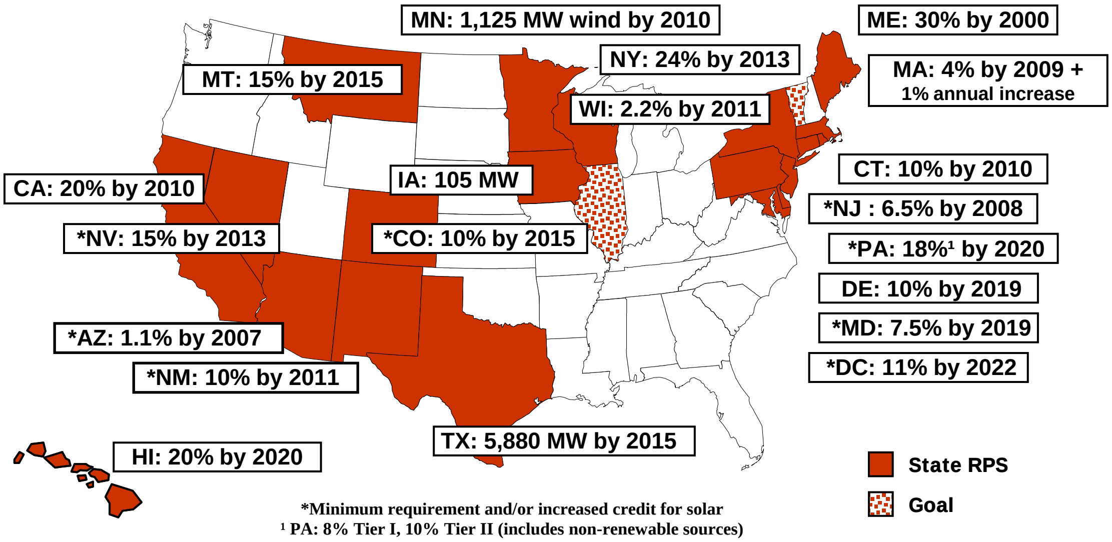

Figure 2: Renewable Energy Portfolio Standards in the United States.
Source: The Database of State Incentives for Renewable Energy (DSIRE).

The RPS approach requires retail providers to account for a prescribed (and generally increasing) percentage of their retail sales with the output from qualified renewable generating facilities. This does not mean that utilities in RPS programs have to contract directly for power from renewable sources, however. Instead, they may purchase the environmental attributes associated with renewable generation, separately from their power purchases, as renewable energy certificates (RECs). These RECs can be used to satisfy a part or all of state RPS requirements, with one REC produced for each MWh of renewable generation. The use of RECs allows utilities flexibility in meeting renewable energy goals, while still guaranteeing that the target amount of generation will be produced from clean, renewable sources every year.

While the definition of qualified RECs differs from state to state, the programs which are most effective at promoting development of renewable resources require that the renewable energy be produced from newer sources to qualify. In Massachusetts and Rhode Island, for example, qualifying sources must have been brought on line after 1997, or consist of incremental generation capacity added to existing facilities after this date. This restriction prevents existing biomass incineration and hydropower facilities from flooding the REC market and driving prices downward,[5] and promotes the goal of encouraging new investment in renewable energy supply. Because the sale of RECs provides an important source of long-term revenue for renewable generation projects, maintaining a REC value which reflects the cost of producing environmental attributes is necessary for meeting state renewable energy goals.

RECs can be traded within and among states in New England, and are tracked and verified through the NEPOOL Generation Information System (GIS). Because state requirements differ, distinct REC markets have developed. The Massachusetts and Rhode

[5] The eligibility rule for Connecticut Class I REC category has been recently modified by allowing existing biomass facilities with adequate emission controls to qualify. This had the effect of flooding the CT Class I REC market and reduced associated prices dramatically.

Island markets have the most stringent requirements and fetch the highest price; and RECs which qualify in these markets would also qualify in other states.

Vermont does not currently have a REC requirement. However, the Legislature adopted specific renewable energy targets under Act 61. This act calls for Vermont utilities to meet all of their growth in energy deliveries from 2004 to 2012, up to 10% of total sales, through renewable energy development supported by long-term contracts.[6] If these targets are not met voluntarily as of 2012, the Public Service Board is required to implement an RPS system similar to that in other New England states. Thus Vermont has no current requirement for purchasing RECs (until 2012), but state utilities have a strong incentive to contract for energy from renewable sources such as Deerfield. In addition, a formal RPS program must be instituted after 2012 if the specified targets are not met. For now, RECs produced in Vermont can be used to meet other states' RPS requirements. RECs produced from new wind projects such as Deerfield would qualify for credit in any RPS program in New England.

Annual renewable energy targets in New England, as a percentage of the total applicable retail sales, [7] are shown in Table 1. These numbers only tell a part of the story because, as noted above, not all programs are equally stringent in terms of qualifications. Maine has the highest renewable percentage requirement in the United States, for example, but its program does little to promote *new* renewable generation because the eligibility requirements are broad enough to include existing hydropower facilities and cogeneration. The combined current output of these sources already exceeds the 30% of retail sales threshold.

Table 1. Renewable energy targets in New England by state and year.

	CT		ME	MA		RI		VT*
	Class I	Class II		Max	Min	New	Old	
2003			30.0%	1.0%				
2004	1.0%	3.0%	30.0%	1.5%				0.0%
2005	1.5%	3.0%	30.0%	2.0%				1.6%
2006	2.0%	3.0%	30.0%	2.5%				3.1%
2007	3.5%	3.0%	30.0%	3.0%		1.0%	2.0%	4.5%
2008	5.0%	3.0%	30.0%	3.5%		1.5%	2.0%	5.9%
2009	6.0%	3.0%	30.0%	4.0%		2.0%	2.0%	6.9%
2010	7.0%	3.0%	30.0%	5.0%	4.0%	2.5%	2.0%	7.8%
2011	7.0%	3.0%	30.0%	6.0%	4.0%	3.5%	2.0%	8.2%
2012	7.0%	3.0%	30.0%	7.0%	4.0%	4.5%	2.0%	9.1%

*The Vermont targets represent the forecast percentage load growth over 2004 levels according to the state electric plan; this would be the renewable energy target under Act 61.

Another source of revenue for renewable energy projects is the voluntary green power market, in which customers choose to pay a premium for their retail power purchases in order to promote the development of renewable energy resources. Although the impact of the voluntary green market has been small compared to that of state RPS, this market has

[6] This program is referred to as Sustainably Priced Energy Enterprise Development, or SPEED.
[7] Existing RPS programs in New England do not apply to municipal and publicly owned utilities.

been growing, and some states are promoting voluntary green power purchases by providing incentives to customers who sign up. For example, Rhode Island has two financial incentive programs for customers participating in the voluntary green programs,[8] and the Massachusetts Technology Collaborative provides a matching fund for renewable energy projects in proportion to the money paid by consumers in these programs.[9] To prevent double-counting and to ensure that the goal of promoting renewable energy development is furthered, RECs which are sold through voluntary programs are not available to meet state RPS requirements.

Figure 3 presents a visual representation of the projected growth in renewable energy demand in New England from 2004 to 2012 due to RPS policies, Vermont's SPEED program, and voluntary green power programs. According to these data, New England retail providers will be required to produce or procure almost 5000 GWh from new renewable energy development under RPS, plus almost 200 GWh under voluntary markets, in 2009.[10] The primary demand is in Massachusetts (2,180 GWh) and Connecticut (2,110 GWh), although as noted above, the Connecticut market is now open to a much broader range of resources. Starting in 2010, Massachusetts plans to increase its target by 1% annually unless the Division of Energy Resources (DOER) elects to suspend the increase. Assuming DOER allows the program to go forward, we estimate that New England would produce or procure approximately 7,000 GWh from RPS and 420 GWh from voluntary green markets by 2012.

The demand for renewable energy in Vermont itself is projected to be 630 GWh in 2012. Reaching this goal will require four to six projects the size of Deerfield to be on line by 2012.

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[8] The Rhode Island Renewable Energy Fund at http://www.riseo.state.ri.us/riref/programs/index.html .
[9] The Massachusetts Technology Collaborative at http://www.cleanenergychoice.org/learn_more.htm .
[10] The RPS effects are estimated by applying state-specific targets to the retail load forecasts by the ISO-New England's CELT report, available at http://www.iso-ne.org/. The potential of voluntary green market in the states of New England region are based on the assumptions used for the Regional Greenhouse Gas Initiative. See Sustainable Energy Advantage, LLC and LaCapra Associates, 2005, "RGGI Renewable Energy Modeling Assumptions," presentation on October 15, 2004.

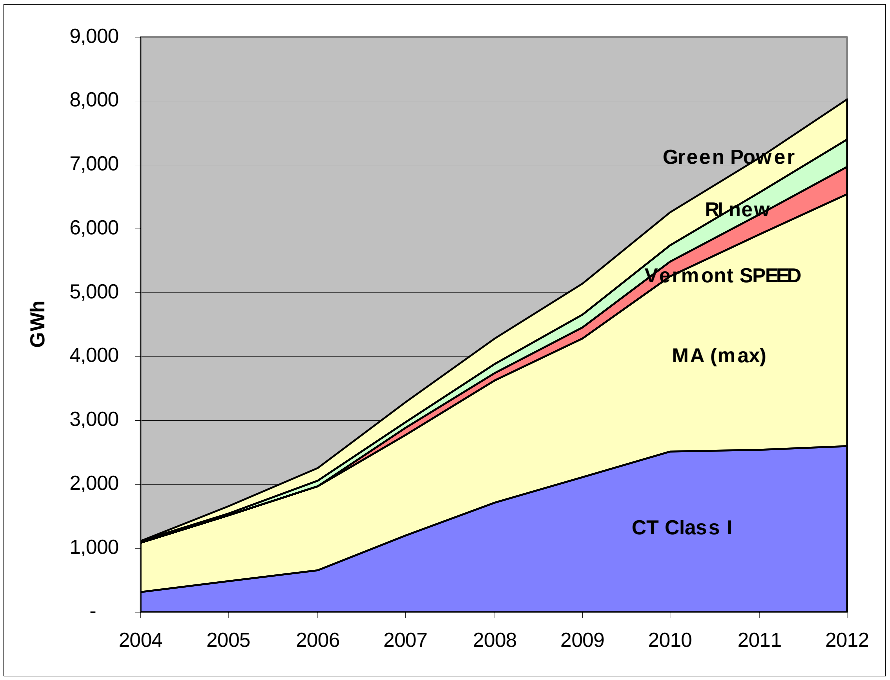


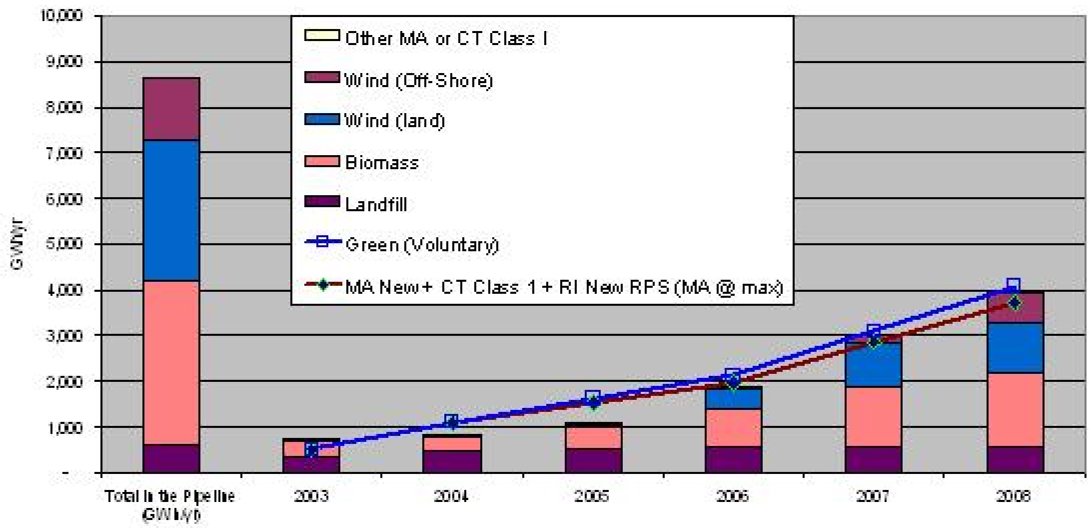
Figure 3: Cumulative new renewable energy targets in New England[11]

Today, the Massachusetts REC market is experiencing a significant supply shortage, resulting in the highest REC prices in New England at over $50 per MWh equivalent.[12] This REC price is very close to the alternative compliance payment (ACP) that Massachusetts utilities can make in lieu of purchasing RECs. In 2004, roughly 40% of the Massachusetts target was met through the ACP.[13] Although the Massachusetts DOER expects a substantial number of new renewable energy projects in the future, the REC supply may be expected to remain stretched as new RPS requirements commence in New York in 2006 and Rhode Island in 2007, and as the renewable percentage obligation in Connecticut increases starting in 2007.[14] It is not clear how the SPEED program in Vermont will affect the region-wide demand for RECS, but if a compulsory RPS program is instituted in Vermont in 2012, this would represent an additional significant market for RECs at that time.

One estimate of the supply/demand balance for RECs was provided by Robert Grace of Sustainable Energy Advantage (Figure 4). This study investigated the renewable energy project pipeline in New England and compared likely renewable capacity for each year with demand from state RPS and voluntary green power programs. Projects shown for each year are derated according to Mr. Grace's estimate of their probability of success. As seen in Figure 4, demand and supply remain quite closely linked over this period,

[11] CT indicates new renewable energy from Connecticut Class I and RI indicates Rhode Island's new renewable energy.
[12] As of July 25, 2006, Massachusetts RECs were trading at $53/MWh for a one year REC according to Evolution Markets (http://www.evolutionmarkets.com/).
[13] Massachusetts Division of Energy Resources, February 2005, *Renewable Energy Portfolio Standard Annual RPS Compliance Report for 2003.*
[14] Ibid.

suggesting that REC prices will continue to support new resource development. The pipeline shown includes the Deerfield project, referred to in his study as EnXco Searsburg/Readsboro, with a range of 30 to 45 MW capacity.



Source: Robert C. Grace (Sustainable Energy Advantage, LLC), 2005, "New England Renewable Energy Supply & Demand Outlook," presentation to RI Renewable Energy Fund on February 18, 2005.

Figure 4. Projected supply and demand for renewable energy in New England. The left-most column shows all known renewable projects in the pipeline, and other columns show R. Grace's estimate of likely projects in service for each year. The lines show Grace's projections of renewable energy demand with and without voluntary markets during this period.

We conclude that there is a strong and growing demand for renewable energy and RECs in the region, which will continue to require and support new projects over the coming decade and beyond. The Deerfield project can play a role in meeting this demand both in Vermont and region-wide, and the project economics will be strengthened by continuing demand for RECs in Massachusetts and Rhode Island, and likely in other states as well.

III. Air Quality Benefits

The addition of wind energy to the regional electricity grid has the benefit of decreasing the emission of harmful air pollutants, such as NO_x, SO_2, and CO_2, from fossil fuel-fired electric generating plants (and to some degree, biomass plants).[15] These pollutants are associated with social and economic costs[16] related to adverse health impacts, acid rain, regional haze, and global climate change. Some of these economic impacts, in some regions, are quantified and internalized in the cost of emission allowances. In this case

[15] Other pollutants, not included in this analysis, include mercury and fine particulate matter. Mercury emissions are generally associated with coal combustion, and the benefits of displacing oil and gas generation are minimal in this respect. Fine particulates have only recently been recognized to be a significant health risk and may well be regulated in the future. This would represent an additional significant environmental and economic benefit for emissions-free wind generation.

[16] See for example US EPA Clean Air Interstate and Clean Air Mercury Rules.

they are ultimately passed on to the consumer in the form of higher electricity prices. Other impacts remain as external costs which are borne by the surrounding region (or in the case of greenhouse gases, through the global impact on climate) but are not internalized in the cost of electricity.

The production of electricity from wind produces no pollutants, and in fact reduces overall regional pollutant emissions by reducing the load on conventional sources of energy. This environmental benefit can be quantified by estimating the emission rates of power plants which are displaced as a result of the new wind energy. The economic benefit of displacing fossil fuel generation and its associated emissions can also be estimated. These economic benefits are diverse, widely dispersed and their quantification involves significant uncertainty; however, there are often regulatory or market indicators which offer some indication of their general value to society. For this study, we rely on the language of Vermont Public Service Board Orders 5270 and 5980 to provide statutory guidance on estimating this value.

Near-term marginal emission displacement

For near term analysis (up to four years), the first step in determining displaced emissions associated with wind energy production is to determine which unit or units would be *marginal* in any given hourly dispatch. System operators generally dispatch generating units in economic merit order–that is, in order of increasing operating costs per MWh produced. New resources with low operating costs, such as wind, effectively “shift up” all of the more expensive units, lowering overall operating cost by specifically reducing the output of the least efficient unit or units running, referred to as the marginal units.[17] It is these units which will be backed down when new sources are brought on line, so it is their emission rates that should be considered when calculating short-term avoided emissions. This number is then multiplied by the projected output of the renewable resource to forecast total displaced emissions.

There are several considerations to keep in mind when calculating displaced emissions based on the marginal unit:

- The marginal unit will be different under different load levels, as the number of resources required to meet load varies.
- Loads rise during the day and fall at night. The lowest cost generating units – base load units – operate at full load around the clock. In New England, these might be hydropower and nuclear units, which have very low fuel costs and zero emissions. Their output is unlikely to be affected by the addition of a wind generator to the system.
- Higher cost units are turned on or off as the load fluctuates, increasing their output during the day, for example, and decreasing it during the night. In New England these include a large number of gas-fired combined-cycle (CC) units.

[17] More than one unit can be marginal during any hour for a number of reasons, including transmission constraints and the ability of only certain units to change their output rapidly to follow load. This complexity would not significantly affect the calculation of displaced emissions in this study, and is therefore not considered.

More expensive (less efficient) gas- and oil-fired units are brought on line during the daytime when loads are highest, and gas- or oil-fired combustion turbines (CTs) may be dispatched only during the highest few peak hours per year.

Figure 5 is a simplified representation of plant dispatch in a hypothetical system during a typical summer week. Note that the base load units such as coal, hydropower[18] and nuclear are run during all hours, while the more expensive units are only used when required to meet load. During most hours of this week, the gas and oil peaking units are on the margin; during lower load hours gas CCs are on the margin, and during a few peak hours combustion turbines play this role.

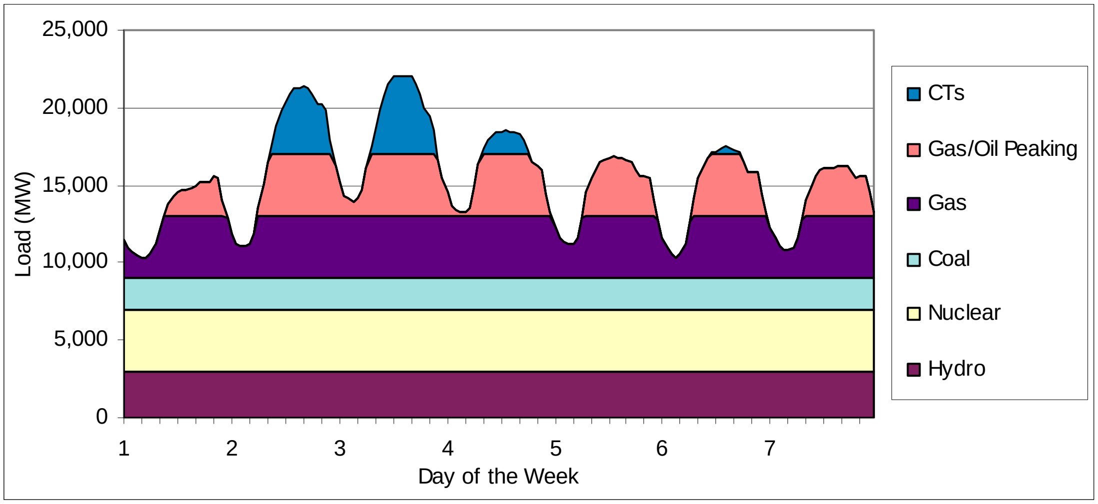


Figure 5. Hypothetical generating unit dispatch during a typical summer week

Long-term marginal emissions displacement

For longer-term analysis (greater than four years), the most significant impact to be modeled is the effect of additional resource on capacity investments and retirements in the region. The underlying assumption is that the system will have had time to re-equilibrate through new entry and retirements so that peaking units, for example, will experience the same load factor that they would have experienced in the absence of the new resource. The approach in this case is to use the emissions characteristics of the most likely marginal units to be built or retired, and apply this rate to the output of the new unit. For the purposes of this study, the following assumptions were made:

- New units added are assumed to be gas-fired combined-cycle units with NO_x controls (SCR). These units are assumed to have heat rates of 7,000 Btu per kWh and NOx emission rates of 0.06 lb/MWh. SO_2 emissions are assumed to be zero.[19]
- Old units retired are oil- or oil/gas-fired steam units built before 1960. Emission rates are assumed to be: 2.4 lb/MWh NO_x and 1.8 lb/MWh SO_2. These rates are

[18] Hydropower units serve a variety of purposes in interconnected electric grids, depending on specific characteristics. Base load hydropower is available from so-called run of the river plants with no storage. On the other hand, hydropower facilities with storage capability are often used as peaking units.
[19] AEO 2005.

the average of all the pre-1960 oil and oil/gas steam units in ISO New England, New York ISO and PJM.

- Because the demand for electricity is assumed to be growing in general, capacity added is assumed to be greater than capacity retired by a ratio of three to one.[20]

Displaced Emissions Benefit of the Deerfield Project

To quantify the expected displaced emissions associated with the Deerfield wind project, we relied upon a displaced emissions workbook developed by Synapse Energy Economics, Inc. for the Ozone Transport Commission.[21] To produce this workbook, short-term displaced emissions were calculated based on a series of hourly simulations using the PROSYM power system dispatch model to determine the weighted average marginal emission rates of NO_x, SO_2, and CO_2 for on and off-peak periods, during the ozone season (summer) and non-ozone season (winter). Long-term displaced emissions were based on the new entry and retirement unit characteristics as described above. The short-term analysis approach is used for years one through four of the project's operation, and the long-term approach for years eight and beyond. During the intermediate period (years five through seven) we assume that both effects play a role, and use displaced emission rates intermediate between the short- and long-term values.

We begin with a projection of an overall 36% capacity factor based on data collected by Deerfield at the proposed site.[22] We determined wind resource output characteristics in Vermont based on data from the US Department of Energy,[23] finding that the output during the winter period (October through April) may be expected to be just over twice as great as during the summer period. Using these parameters, we forecast the total annual displaced emissions associated with the project, for project sizes of 30 and 45 MW nameplate capacity.[24] Note that due to the overall dispatch process in the region, the specific reductions in emissions may occur anywhere in the northeastern United States or eastern Canada. These results are shown in Table 2.

[20] Keith, G., D. White and B. Biewald, *The OTC Emission Reduction Workbook*, prepared by Synapse Energy for the Ozone Transport Commission, 2002. The workbook is available at http://www.synapse-energy.com/Downloads/Synapse-otc-workbook%202.1.zip; the manual may be found at http://www.synapse-energy.com/Downloads/Synapse-otc-workbook%202.1-manual.pdf.
[21] Ibid.
[22] Deerfield estimates that the project will have a capacity factor of between 36% and 38%, substantially better than the performance of the existing Searsburg wind farm nearby. This is due to the superior location and increased height of the proposed project relative to Searsburg. We use the more conservative estimate of 36% throughout this analysis.
[23] National Renewable Energy Laboratory, *Wind Energy Resource Atlas of the United States*, 1986. Available at: http://rredc.nrel.gov/wind/pubs/atlas/.
[24] The project is designed to have a nameplate capacity of up to 45 MW.

Table 2. Forecast of avoided emissions attributable to Deerfield Wind Project.

Annual Avoided Emissions (tons)			
	Weighted Average Emission Rate (lbs/MWh)	**Annual emissions reduction at 30 MW**	**Annual emissions reduction at 45 MW**
	Years 1 through 4		
NOx	2.0	94	141
SO2	5.4	257	386
CO2	1,415	66,924	100,386
	Years 5 through 7		
NOx	1.3	64	96
SO2	3.0	140	211
CO2	1,227	58,060	87,090
	Year 8 and Beyond		
NOx	0.7	33	50
SO2	0.5	24	35
CO2	1,040	49,196	73,794

Valuation of avoided environmental externalities in Vermont

In addition to the quantification of displaced emissions, we can estimate the economic value of these avoided environmental externalities. Because these benefits are widely dispersed and their quantification involves uncertainty, it is helpful to look to regulatory guidance on the valuation of these benefits in Vermont.

In Public Service Board (PSB) Docket 5270, Order of April 16, 1990, the PSB directed that in performing a total resource cost comparison, a 5% adder to the avoided cost be used in evaluating demand-side investments to represent the avoided cost of environmental externalities. In so doing, the Board described this as a conservative estimate, and that the true value may "significantly exceed 5% of the current market price of some supply technologies."[25]

In addition, the Board mandated a 10% reduction in the estimation of demand side program costs for planning purposes, to reflect their lower risk relative to conventional generation resources. Although not based on a specific, analytical quantification of avoided costs, both of these values have been accepted by the Board in other dockets in the intervening years and thus reflect a consistent indication of the Board's expressed valuation of alternative resources.

The 5% environmental externalities adjustment is clearly appropriate for use in this case, as the displaced emissions associated with wind energy generation are exactly the same as those associated with a demand-side resource. The applicability of the 10% cost reduction is more subtle, and requires a consideration of the specific risks associated with fossil fuel generation that would be negated by wind power generation. The advantages

[25] Vermont Public Service Board Docket No. 5270 Order, Volume IV, Page 8.

related to reduced risks that the Board cited in the Order in Docket 5270 include short lead times, availability in small increments and simultaneous growth with loads; these benefits are not provided by Deerfield. Other averted risks have to do with risks to fuel supply, fuel cost, and emissions costs, and these risks are avoided by Deerfield. Once a mature renewable energy resource such as Deerfield is in place, it produces emissions-free energy immune to any fuel supply or pollution issues; in this sense it is equivalent in impact to a demand side resource. Thus we conclude that it is appropriate to consider both the 5% adder to represent avoided environmental externalities, and one-half of the 10% discount on project cost to represent avoided risk, in quantifying the economic benefit of displacing fossil fuel based generation with the Deerfield project.

As discussed in Section IV, we project the direct avoided energy costs associated with the Deerfield project to be approximately $60/MWh over the life of the project, based on a recent study by the New England AESC Study Group.[26] In addition, we estimate that the all-in cost of production will be $64 per MWh produced. By this analysis, the benefit of avoided emissions and risk, based on Docket 5270, is 5% of $60, plus 5% of $64, or a total of $6.20 per MWh of generation.

In 1999, the Board issued an order in Docket 5980 that provides a similar value for avoided environmental externalities from another perspective. While explicitly limited in scope and precedential value, this Order accepted an 0.7 cents/kWh adder to replace the 5% rebuttable presumption from Docket 5270. PSC staff has updated the 5980 value to $8.30 per MWh, in 2006 dollars, to account for inflation[27].

The estimated benefits associated with avoided environmental externalities, calculated following each of these standards, is shown in Table 2.

Table 2. Projected annual avoided environmental externality cost associated with Deerfield, assuming a 36% overall capacity factor.

	Annual Avoided Externality Value	
Avoided Cost Model	*30 MW Capacity*	*45 MW Capacity*
Docket 5270	$0.58 million	$0.88 million
Docket 5980	$0.74 million	$1.11 million

IV. Economic Analysis

In this section we present a preliminary comparison of the costs and revenues we would anticipate for the Deerfield project. All of the data used in this analysis are based on public sources, although some of the financial model parameters have been checked for reasonableness and applicability with personnel associated with the Deerfield project. We find that, given recent electricity price projections and a capacity factor of 36%, electricity market revenues alone are likely to provide sufficient income to sustain the project. However, additional revenues from the capacity market and from the sale of

[26] AESC post-Katrina study under development, to be available to the general public in January, 2006.
[27] Based on updated spreadsheet for calculating avoided costs and externality values (DSM Screening Tool) provided to Synapse by Dave Lamont of the Vermont PSC.

renewable energy credits will provide a crucial margin of confidence. Indeed, this is the very reason for the existence of these two markets.

We further find that future electricity prices may be significantly higher than current projections suggest, due either to higher than expected fuel costs or to costs associated with air emissions, including emissions of greenhouse gases. Zero emissions, renewable energy sources such as the Deerfield project, whose production costs are insensitive to fossil fuel prices, represent a valuable long-term hedge against both of these.

Estimated project costs

To project the annualized cost of the Deerfield project, we implemented a standard levelized cost model with the input assumptions as shown in Tables 3 and 4. All calculations are performed on a per kW-yr or per-MWh basis, for fixed and variable costs, respectively, in real 2005 US dollars. The data shown here were provided by Deerfield Wind and are consistent with Synapse estimates based on market observations and review of public sources. While these costs are representative of realistic project costs in this region, they do not necessarily reflect actual costs or financing plans for any specific Deerfield project configuration.

Table 3. Financial model parameters

Project output	
Capacity factor	36%
Annual generation per MW capacity	*3154 MWh*
Fixed Costs	
Fixed O&M	$18.75 per kW-yr
Insurance	$8.35 per kW-yr
Property Tax	$10 per kW-yr
Total Fixed Costs:	*$37.10 per kW-yr*
Variable Costs and Credits	
Variable O&M cost	$5 per MWh
Annual land payment cost*	$2.40 per MWh
Production tax credit (PTC)**	($19) per MWh
Net Variable Costs:	*- $11.60 per MWh*

Table 4. Financial model parameters (continued)

Financial Parameters	
Cost of debt	8%
Cost of equity	14%
Debt/equity ratio	50:50
Blended cost of capital	11%
Book life	20 years
Tax life	5 years
Federal tax rate	34%
State tax rate	9%
Capital Recovery Factor:	*10.56% per year*

*Land payment is calculated as 3.5% of gross revenues assuming an estimated electricity price of $68/MWh
**PTC is inflation-adjusted from the original value of $15/MWh in 1992.

Based on these inputs, we estimate that the all-in cost of production would be $64 per MWh produced.

Estimated project revenues

The cost calculated above may be compared to projected "avoided costs" of approximately $60/MWh over the next several years, as projected by the most recent New England AESC Study Group analysis.[28] Avoided cost represents the marginal cost of energy production from other sources that would be negated by an alternative source of energy, such as the Deerfield project, or from an energy efficiency initiative. Under the market structure in NEPOOL, this is the revenue that the Project would receive in the spot market, and it is also the projected revenue that would most likely be used in structuring a long-term energy contract.

In addition, although the details of the future capacity market structure in NEPOOL are in flux, the Deerfield project is likely to earn capacity payments at a level corresponding to its capacity factor. If we assume that the capacity price will be between $3 and $8 per kW-month[29], and using the parameters in Table 3, the project will receive between $4 and $11 per MWh produced in capacity payments.

As another source of revenue, Deerfield would be able to sell the environmental attributes of its production as RECs in the high-priced markets in Massachusetts and Rhode Island as discussed above. In 2005, Massachusetts retail providers paid prices which approached the alternative compliance cost of $53.19 per MWh[30] due to a severe shortage of available RECs. There is considerable uncertainty regarding the future price of RECs because any change in eligibility requirements can cause a large shift in the balance between supply and demand. Regulators are under pressure on the one hand to promote strong renewable energy development, and on the other to avoid an undue burden on utilities that will ultimately be passed on to consumers. In addition, one large project, such as the proposed offshore wind farm new Cape Cod, could significantly alter the dynamics of the REC market and produce a reduction in price.

Nonetheless, the purpose of RPS programs is to promote development of renewable energy, and this remains the policy goal of several northeastern states. It is unlikely that these programs will be rendered meaningless by regulatory fiat, and the annually increasing requirements suggest that they will continue to support the development of new resources in the coming years. In addition, the current supply shortage of wind turbines in the United States makes it unlikely that a large amount of new wind capacity will come on line quickly to compete in this market. Our analysis shows that RECs are

[28] ICF Consulting, Inc., "Avoided Energy Supply Costs in New England", prepared for the New England AESC study group, December, 2005.
[29] This represents Synapse' estimate of future capacity payments under various proposed capacity market structures under consideration. The ISO's proposal has a target price based on the carrying charges of a new peaking plant net of energy revenues, or about $8 per kW-month. Current capacity market prices are considerably lower.
[30] Massachusetts Division of Energy Resources, http://www.mass.gov/doer/.

likely to provide a significant and important additional source of income for the Deerfield project but, given the likely revenue streams from the energy and capacity markets, high REC prices are not necessarily required for financial viability.

Hedge value of fuel price insensitive power

The electricity price projections based on "avoided cost" estimates, described in the previous section, represent one possible future price trajectory. It is entirely possible that electricity prices could be much higher.

Figure 6 shows the monthly average day-ahead prices for the Vermont zone in NEPOOL. As is evident in Figure 6, prices rose dramatically during the summer of 2005 and have remained generally high by historical standards ever since. Specifically, they have been consistently higher than the $60/MWh that we have forecast based on AESC avoided cost study data. These high prices reflect the high cost of natural gas, at least part of which is generally associated with supply disruptions from hurricanes Katrina and Rita during the summer.

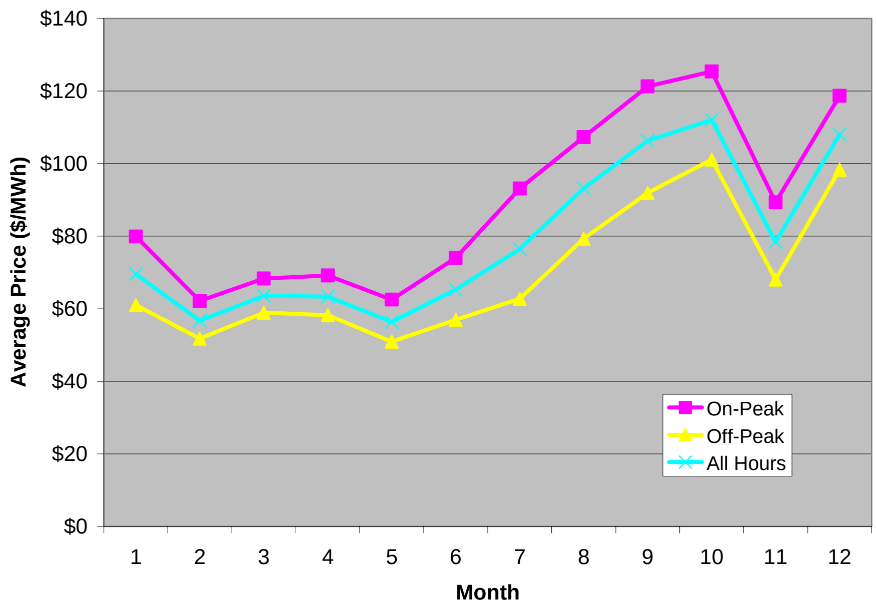


Figure 6. 2005 monthly average day-ahead electricity prices in the Vermont zone.

There are many reasons to expect that gas supplies will remain constrained for the foreseeable future, and that gas prices (and consequently electricity prices) will remain at an elevated level. For example, NYMEX prices[31] posted in December 2005, for the first months of 2006, are $14 per million BTUs; the futures remain around $10 or above per million BTUs into 2008. Beyond this period the prices begin to decline but this is a poor indicator of investor expectation as it reflects almost no trading activity. Gas prices at this level suggest electricity prices which would be $80 to $100 per MWh for much of the year, and much higher during peak hours.

[31] www.NYMEX.com.

While some of this current high gas price may be a residual effect related to the recent hurricanes, this is clearly not the whole story. Natural gas prices have been pushed upwards recently both by escalating demand (a large number of new, gas-fired power plants have been built in the last five years) and by the dwindling productivity of domestic sources of supply. Because of these factors, many more new gas discoveries have been required each year to keep up with growth in demand. For example, according to a September, 2005 EIA report,[32] during the five years from 1995 to 1999 an average of 12,233 natural gas wells were completed each year in the United States for total discoveries of 18.7 trillion cubic feet (tcf) of gas. During the subsequent five years from 2000 to 2004, the yearly average was 19,828—a 62% increase in the number of new wells. However, annual gas discoveries for those same years totaled just 19.4 tcf, just 3% greater than the previous five years' average. As this illustrates, natural gas recovery in the United States is becoming progressively more difficult, more expensive, and less productive, at the same time that demand continues to increase due in large part to increasing demand for gas-fired generation.

Finally, we note that there are about 45 current proposals for new liquefied natural gas (LNG) import terminals in the United States. While it is clear that not all of these will be built, and indeed there would be insufficient global supply of LNG to serve them all, the fact that so many investors are endeavoring to develop these LNG assets suggests that the market expectation is for gas prices to remain high for the foreseeable future.

In addition to the risk associated with fuel cost and supply, fossil fuel generators (and consumers) face the prospect of much higher emissions costs in the future due to regulation of carbon dioxide and other greenhouse gases. This could drive the price of electricity up by $10/MWh or more, depending on the details of the regulations and the technologies available to control emissions. Electricity production at Deerfield would emit no greenhouse gases, and would not be subject to these costs.

The cost of production for most of the new generation investments throughout New England is sensitive to the price of natural gas and the future cost of greenhouse gas emissions. Production costs for Deerfield are not. This represents a significant hedge value for this project in the face of great uncertainty and risk in the electricity market as a whole.

V. Conclusion

The Deerfield project represents a reliable and much needed source of power, with long-term cost stability, in a region in which the availability of cost-stable resources is quickly diminishing. The impending expiration of long-term contracts with Entergy (for power from Vermont Yankee) and with Canadian hydropower sources makes it imperative that utilities find alternative sources for long-term, price-stable supply. The Deerfield project is likely to represent such a resource.

[32] Office of Oil and Gas, U.S. Energy Information Administration, *Advance Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2004 Annual Report*, September, 2005. Available at http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2004/adsum2004.pdf.

In addition, the Deerfield project will serve as a supply of renewable energy consistent with the Vermont SPEED requirements, and of renewable energy credits to satisfy renewable portfolio standards throughout New England. In addition, the development of in-state renewable energy sources today will serve as a source of RECs in the event that Vermont institutes its own RPS program in 2013, retaining the full value of renewable production for Vermont.

We find that the project would offer significant air quality and reduced emissions benefits to the region, preventing the annual emissions of hundreds of tons of NO_x and SO_x that cause acid rain, smog, and adverse health impacts. In addition, the project would prevent hundreds of thousands of tons of CO_2 from entering the atmosphere over the life of the project, contributing to the fight against global climate change. We find the economic value of these direct environmental benefits to be in the range of $0.6 million to $1.1 million annually, based on the project size and the Public Service Board's guidelines for valuing avoided environmental externalities in electricity markets.

Finally, we find that the project is likely to be economically viable in the current market environment for electricity and for renewable energy attributes, and that it may be extremely cost-effective if natural gas prices continue to increase, or if carbon emissions regulations come into force, in future years.