THE STATE OF NEW HAMPSHIRE
SITE EVALUATION COMMITTEE

In the matter of the Application for Certification Pursuant to RSA 162-H of ANTRIM WIND ENERGY, LLC	)	**Docket No. 2012-01**

NOTICE OF DISCLOSURE OF REDACTED REPORT AND FILING OF UNREDACTED REPORT WITH THE COMMITTEE

1. On June 18, 2012, pursuant to RSA 162-H:10, Counsel for the Public moved for authorization to retain Deloitte Financial Advisory Services to conduct a study and prepare a report of its analysis of the Applicant's business plan and financial capability. The motion indicated that the Deloitte report would be available before the testimony deadline but that Deloitte would not be present for cross examination for the budgeted fee. The motion stated that in the alternative, for additional compensation, Deloitte would be available to testify. Motion ¶ 4.

2. On July 11, 2012, the Presiding Officer entered an order granting Counsel for the Public's Motion. In the Order, the Presiding Officer took note of the fact that under the amount budgeted Deloitte would not be available for live testimony. Order at 6.

3. Due to Applicant's requirement that it would not release confidential information to Deloitte without a protective order from the Committee, work on the Report did not begin in earnest until after August 22, 2012.

4. Deloitte did not participate in technical sessions and no data requests were directed towards it and thus none were answered. Deloitte did not submit any prefiled testimony.

5. On September 24, 2012, Deloitte provided Counsel for the Public its final Report.

6. During its research, Deloitte obtained certain confidential information from the Applicant and made reference to such in its Report. Deloitte has redacted certain information that the Applicant claims is confidential.

7. On October 18, 2012, the Presiding Officer ordered Counsel for the Public to provide the parties a copy of the attached redacted report. The extent of the redactions and whether redacted information should be made available to parties willing to enter into confidentiality agreements is contested by Counsel for the Public and the Applicant and is

under consideration by the Presiding Officer. Submission of this redaction is without prejudice to Counsel for Public's arguments and objections with respect to those issues.

8. Simultaneously with the service to the parties of the redacted version, Counsel for the Public hereby submits the unredacted Report to the Committee under seal, subject to the Presiding Officer's decision on the Applicant's clarification motion of October 1, 2012. This submission is pursuant to RSA 162-H:10, III, IV and V.

Respectfully submitted this 19th day of October, 2012,

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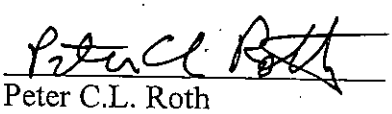
Certificate of Service

I, Peter C.L. Roth, do hereby certify that I caused the foregoing to be served upon each of the parties named in the Service List of this Docket.

Dated: October 19, 2012



Peter C.L. Roth

Report

Deloitte.

Financial Advisory Services

State of New Hampshire

Office of the Attorney General

Analysis of the Wind Generation Facility Proposed to be Built in Antrim, New Hampshire

Report Date: September 26, 2012

Audit.Tax.Consulting.Financial Advisory.

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Report

Prepared for

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Executive Summary

We assisted the State of New Hampshire with its assessment of a proposed 30 megawatt ("MW") wind power generation project in the Town of Antrim, New Hampshire (referred to hereafter as "Antrim Wind Project" or the "Project"). Antrim Wind Energy LLC ("AWE") is the Project's sponsor and has filed an application with the New Hampshire Site Evaluation Committee to gain approval of the proposed site to construct the Project. We performed assessments of the market for financing development-stage wind projects, the Project's business and funding plans, and the Project development team. Based on our analysis, our comments are provided below.

Market Assessment

In recent years, investment in wind power has grown significantly, spurred by federal and state tax incentives and state renewable portfolio standards ("RPS"). Going forward, the ability to develop new wind projects will depend, to a large extent, on the ability of developers to sign power purchase agreements ("PPAs") with offtakers at prices that provide an acceptable rate of return to the investors in the project. PPAs are in short supply relative to demand as low gas (and therefore electricity) prices and low Renewable Energy Certificate ("REC") prices have made it less expensive for utilities to meet RPS without entering into PPAs with owners of renewable projects or buying/developing such projects themselves.

In addition, the currently planned expiration of the Production Tax Credit ("PTC") at the end of 2012, will put additional pressure on the economics of wind projects as, all else equal, PPA prices will need to increase to provide acceptable rates of returns to investors. Even if the PTC is extended, the availability of tax equity financing (i.e. financing from equity investors with sufficient taxable income to be able to take advantage of the PTC and other tax benefits) is low.

In addition, forecasting future REC prices is difficult, especially in New Hampshire, given the intrinsic link between the New Hampshire market, the markets in the other New England States, and the New York market. Changes in the Connecticut and Massachusetts RPS policies are certain to affect the New Hampshire REC market, as those states comprise the largest loads in ISO-New England ("ISO-NE"). This has resulted in a wide range of expert views on future REC prices.

Despite these uncertainties, IBISWorld expects that, despite the possible expiration of the PTC, demand for wind turbines will likely continue, even if at a lower rate of growth, due to other favorable incentives,

strong interest in sustainable energy, and state RPS requirements. However, potential wind investors will likely be more selective in choosing wind investments due to these uncertainties.

Project Business Plan Assessment

In general, the Applicant had a reasonable basis for its estimates of the capital cost, revenue expectations, operating costs, and economic useful life of the Project. We made high-level comparisons of key assumptions based on publicly-available data on the cost and operating performance of other wind power projects and on assumptions made by the National Renewable Energy Laboratory ("NREL") in its economic analysis of wind power projects. In the absence of sufficient publicly-available data on recent PPA prices for wind projects, we also prepared an analysis to estimate an "all-in" market price that potential offtakers might consider as an alternative to signing a PPA with the Project.

The Applicant's assumptions were generally within ranges observed for comparably-sized projects in New England and were in line with assumptions made in NREL's analyses. We highlight two specific assumptions with respect to the revenue forecast for the Project, which we believe would lead a potential investor to execute additional due diligence : 1) The capacity factor (electricity production level relative to Project capacity) appears to be high relative to comparably-sized projects in New England. By way of explanation, the Applicant has indicated that the large turbines that it plans to use are capable of achieving higher capacity factors at a given site than the more commonly used small turbines and has provided a wind study supporting the assumption. We are not qualified to assess the reasonableness of this assumption; 2) The required PPA price to achieve satisfactory project economics (especially if the PTC is not available) is higher than our estimate of an "all-in" market price that potential offtakers might consider. However, estimates of future "all-in" prices vary widely and the Applicant has indicated that it is aware of wind PPAs that have been signed recently at prices that are supportive of its pricing assumptions. We were not able to verify this based on publicly-available data since there is little data available on PPA pricing.

Funding Plan Assessment

While the proposed terms provided by the Applicant for its non PTC case are outside of the parameters we observed through our discussions with financing sources active in the wind power market, we believe that the proposed terms should give the project enough room to absorb potential higher interest rates and larger equity capital requirements, and still meet the fixed charge requirements of lenders.

Given this, and the fact that CP Energy Group LLC, a well-known capital advisory group in renewable energy, is assisting in the financing aspects of this project, it appears likely that the Antrim project can be financed if the Project can attract a PPA with pricing that allows for adequate return to investors. The financeability of the project is contingent on the Project producing cash flows with a fixed charge coverage ratio of no less than [confidential material redacted], which is driven by a qualified PPA at approximately [confidential material redacted] per MWh in combination with a capacity factor approximating that stated by the Applicant.

Development Team Assessment

Based on the information provided to us by the Applicant and through our independent research we note that the majority of the development team has direct experience in wind and other power project development and financing. Based on additional research, which included searches of a number of proprietary databases that we subscribe to, we did not find any information that would negatively impact our conclusion that the team appears to be qualified to develop the Project.

Purpose and Use

The Services and this report (the "Deliverable") are solely for the State's internal use to assist it in its assessment of the Project. We understand that the Client intends to submit this Deliverable to the Committee as one of several items the Committee will review in its assessment of the Applicant's application for site approval.

Project Overview

Proposed Facility Description

The Antrim Wind Project is proposed to be a 30 MW, utility scale, wind energy generation facility located in the northwest portion of Antrim, NH. The Project will consist of the installation of ten wind turbine generators each with a nameplate generating capacity of 3 MW, a new access road, and an electrical substation along with electrical collector lines. AWE estimates that the Project will have an average annual net capacity factor of [confidential material redacted] to [confidential material redacted] percent. Based on this projected capacity factor, the Project is expected to produce between approximately 98,000 and 106,000 Megawatt hours ("MWh") of electricity per year.

The Project proposes to interconnect the generated electrical power to the Public Service of New Hampshire ("PSNH") 115 kV line known as L163. According to the Applicant, this eliminates the need for new transmission line construction. The on-site electrical system will include collector lines that are below ground along the extent of the ridge and pole-mounted along the access road to the point of interconnection.

The Project will require the construction of a joint collector system and interconnection substation as well as a maintenance building. The collector and interconnection substations will be located immediately to the north of the PSNH L163 transmission line. The final design of the interconnection substation will be performed by PSNH. The maintenance building is expected to be approximately 3,000 square feet in size.

Ownership Structure

AWE is a joint venture between Eolian Renewable Energy, LLC ("Eolian") and Westerly Wind, LLC ("Westerly Wind"). We understand that Eolian is focused exclusively on utility scale wind energy development and has been actively involved in the Antrim Project since 2009. Westerly Wind is a portfolio company of U.S. Renewables Group ("U.S. Renewables"), a U.S. based private equity firm focused on investing in renewable power, biofuels and clean technology infrastructure.

Overview of Eolian Renewable Energy, LLC

Eolian is based in Portsmouth, NH and was incorporated in 2009 to develop wind energy projects for communities in the U.S. The company also conducts third party carbon audits on its projects. It has projects under development in Maine, New Hampshire, and Vermont. The company is currently led by CEO Jack Kenworthy, who previously served as CEO at Cape Systems, Ltd and as founder and Director of Systems at Cape Eleuthera Institute. Eolian currently has three wind projects under development, with a total planned capacity of approximately 150 MW, in New Hampshire, Vermont and Maine.

Table I
Eolian Projects under Development

Power Plant Name	Planned Capacity (MW)	Operating Status	Type	NERC Region(s)	County/State	Estimated Construction Costs ($000)	Estimated Construction Costs ($/kW)
Antrim Wind Energy Project	30.0	Pre Construction	Wind	NPCC	Hillsborough, NH	45,000	1,500
Seneca Mountain Wind Project	100.0	Pre Construction	Wind	NPCC	Caledonia, VT	220,000	2,200
Mount Waldo Wind Project	18.0	Pre Construction	Wind	NPCC	Waldo, ME	39,600	2,200

Source: SNL Financial; construction costs estimated by SNL

It is our understanding that as of the date of this report, Eolian has yet to fully develop and place into operation a power project of any fuel type.

Overview of Westerly Wind, LLC

On March 9, 2010, U.S. Renewables announced the creation of Westerly Wind to provide development capital and expertise to wind developers working to advance projects. The company is led by CEO Joe Cofelice, who previously served as president of Catamount Energy Corp. and as CEO of American National Power Inc.

The company was incorporated in 2010 and is based in Braintree, Massachusetts. According to information gathered from the Energy Acuity database, Westerly Wind is also currently developing a 500 MW wind farm project located in Floyd County, Texas. Westerly Wind entered a Joint Development with Floyd County Wind Farm, LLC and Tri Global Energy, LLC to develop the project, and recently closed on the initial funding to form South Plains Wind Energy, LLC. The newly formed South Plains Wind Energy, LLC will receive initial development funding from Westerly Wind, LLC.

Overview of U.S. Renewables Group

U.S. Renewables is a private equity and venture capital firm specializing in investments in late venture, emerging growth, and acquisition investments. It seeks to acquire, develop, and manage renewable energy facilities, renewable energy generation projects, and clean fuels projects.

According to Capital IQ, it focuses on investments in geothermal, biomass, concentrated solar thermal, photovoltaic (PV) solar, wind, waste-to-electricity, landfill methane and hydro within the power generation sector. Within biofuels, the firm seeks to invest in ethanol, biodiesel, biogas, biomass pelletization, waste management and remediation, and renewable energy agriculture. Within infrastructure and services it seeks to invest in midstream biofuel assets, renewable energy related services companies, energy efficiency projects, carbon abatement or reduction projects, electricity storage, demand-side management, transmission infrastructure, and water infrastructure.

The firm seeks to invest in the U.S., and typically invests $30 to $70 million per project. It looks to acquire controlling equity interests in its portfolio companies but can also invest via project debt. U.S. Renewables was founded in 2003 and is based in Santa Monica, California with an additional office in New York, New York.

We understand that U.S. Renewables is only expected to contribute approximately $4 million to the Project to cover the cost of development efforts and that it is not expected to contribute additional equity capital to the Project. U.S. Renewables' portfolio companies are presented in the table below.

Table II
U.S. Renewables Power Generation Portfolio Companies[1]

Portfolio Company	Location	Initial Investment Year	Type	Description
FFP New Hydro	Boston, MA	2010	Hydro	FFP New Hydro is pursuing the development of a portfolio of new hydro power projects at existing dams throughout the United States.
Westerly Wind	Braintree, MA	2010	Wind	Westerly Wind is focused on providing development capital and expertise to wind energy projects.
Newberry Geothermal	Bend, OR	2008	Geother mal	Newberry Geothermal is a geothermal exploration and development company working to develop a greenfield power project in central Oregon.
Novo Development Company	Fort Collins, CO	2008	Biomass	Novo Development Company develops, owns, and operates renewable energy facilities.
SolarReserve	Santa Monica, CA	2008	Solar	SolarReserve is a utility-scale solar energy project development company developing over 3,000MW of projects.
Niagara Generation	Niagara Falls, NY	2007	Biomass	Niagara Generation is a 52MW multi fuel power plant located in New York. In 2007, the Project was converted from a coal fired power plant to burn wood biomass and tire derived fuel.
Oski Energy	Reno, NV	2007	Geother mal	Oski Energy is an integrated geothermal exploration and project development company.
Tracy Biomass	Tracy, CA	2007	Biomass	Tracy Biomass is the owner of a 21.5MW wood-fired facility located in Northern California.
Bottle Rock Power	The Geysers, CA	2005	Geother mal	Bottle Rock Power is the owner of a 55MW geothermal project located in northern California. The facility sells 100 percent of its power to Pacific Gas & Electric under a long-term power purchase agreement.
Penrose and Toyon Landfill Gas Conversion	Los Angeles, CA	2004	Biomass	Penrose and Toyon Landfill Gas Conversion is a 10 MW landfill gas to electricity project located in Southern California.

[1] U.S. Renewables Group official website ( ), Accessed 8/20/2012

State of the Wind Power Industry

Overview

The Wind Power industry has grown rapidly. Capacity has increased 30.1 percent annually to 65.9 gigawatts ("GW") in the five years leading to 2012, with an anticipated capacity increase of 14.7 percent from 2011 to 2012. Favorable government assistance has made this energy source cost competitive with other types of electricity generation sources in some portions of the U.S.

Various state and Federal government production and investment tax credits and state government mandates for renewable energy have made it attractive for players to construct wind farms. These incentives lowered the cost of wind power generation, while RPS requirements mandated certain downstream buyers to purchase renewable energy. RPS require electric utilities and other retail electric providers to supply a specified minimum amount of customer load with electricity generated from eligible renewable energy sources.

Stronger economic growth is expected going forward, as well as a continued interest in lifting energy self-sufficiency and reducing greenhouse gas emissions. Most predictions show further growth in 2012, as the cost of wind energy continues to decline as a result of lower wind turbine pricing and as developers rush to capture Federal incentives currently expected to expire at the end of this year. Forecasts for 2013 and beyond, however, span a particularly wide range, depending in part on assumptions about the possible extension of Federal incentives beyond 2012.

The 2011 Energy Information Administration ("EIA") reference case forecast assumes no extension of Federal tax incentives beyond 2012 and forecasts little need for new electric capacity additions over this period, resulting in a precipitous drop in projected 2013 wind installations. Other 2013 forecasts predict wind power capacity additions of 5,900-8,000 MW, presumably on the basis of an assumed continued extension of Federal policy incentives of some form. In total, from 2011 through 2013, these forecasts predict cumulative wind power additions of 12,100 to 26,000 MW; this amount of new wind power capacity would be capable of providing roughly 30-60 percent of the EIA's projected growth in total U.S. electricity demand over the 2011-2014 timeframe.

National Energy Market

Electricity and Natural Gas Prices

Low wholesale electricity prices have continued to challenge the relative economics of wind power facilities installed in recent years. A simple comparison of historical wind power prices to wholesale electricity prices throughout the U.S. demonstrates that while wind power had consistently been priced (on average) at the low end of the range of wholesale electricity prices going back through 2003, the drop in wholesale electricity prices in 2009 pushed wind energy to the top of that range, where it remained in 2010 (latest data available) across all regions of the country.

Although low natural gas prices are, in part, attributable to the recession-induced drop in energy demand, the discovery and early development of significant shale gas deposits has resulted in reduced expectations for increases in natural gas prices going forward. As a result, natural gas prices may not rebound to earlier levels as the economy continues with a slow recovery, putting the near-term comparative economic position of wind energy at some risk. While gas plants cannot be applied to a state's RPS, low gas prices give utilities a cleaner option than coal at a price lower than what many renewable power developers can match. Also gas-fired plants have a key advantage over wind and solar in that they are not intermittent sources that rely on the wind blowing or the sun shining. Unlike wind projects, they have the ability to quickly scale up, or scale down, the quantity of electricity they produce to meet demand.

Environmental Regulations

On December 21, 2011, the Environmental Protection Agency ("EPA") issued its final ruling on Mercury and Air Toxics Standards ("MATS"), which followed the July finalization of its Cross-State Air Pollution Rule ("CSAPR"). Together, the two rules would affect the utility industry by requiring retrofits of coal-fired facilities or possibly forcing plant retirements. Although the Court of Appeals for the D.C. circuit vacated CSAPR in August 2012, it advised that its "decision ... should not be interpreted as a comment on the wisdom or policy merits of EPA's Transport Rule" and that USEPA should "proceed expeditiously" to promulgate yet another replacement for CAIR..." CAIR is the Clean Air Interstate Rule, the predecessor rule to CSAPR. Thus, it is possible that there will be a new environmental rule at some point that will require significant investments in retrofits for coal plants or retirement of some coal plants.

According to Standard and Poor's, the industry has concerns that once MATS and a CSAPR-like rule are implemented, there could be power shortages in certain regions of the country. However, according to a report released by the Department of Energy ("DOE") on December 1, 2011, the two rules were not expected to trigger any resource inadequacy problems, provided that additional capacity was built before 2015 in addition to the increase in capacity that had already been planned.

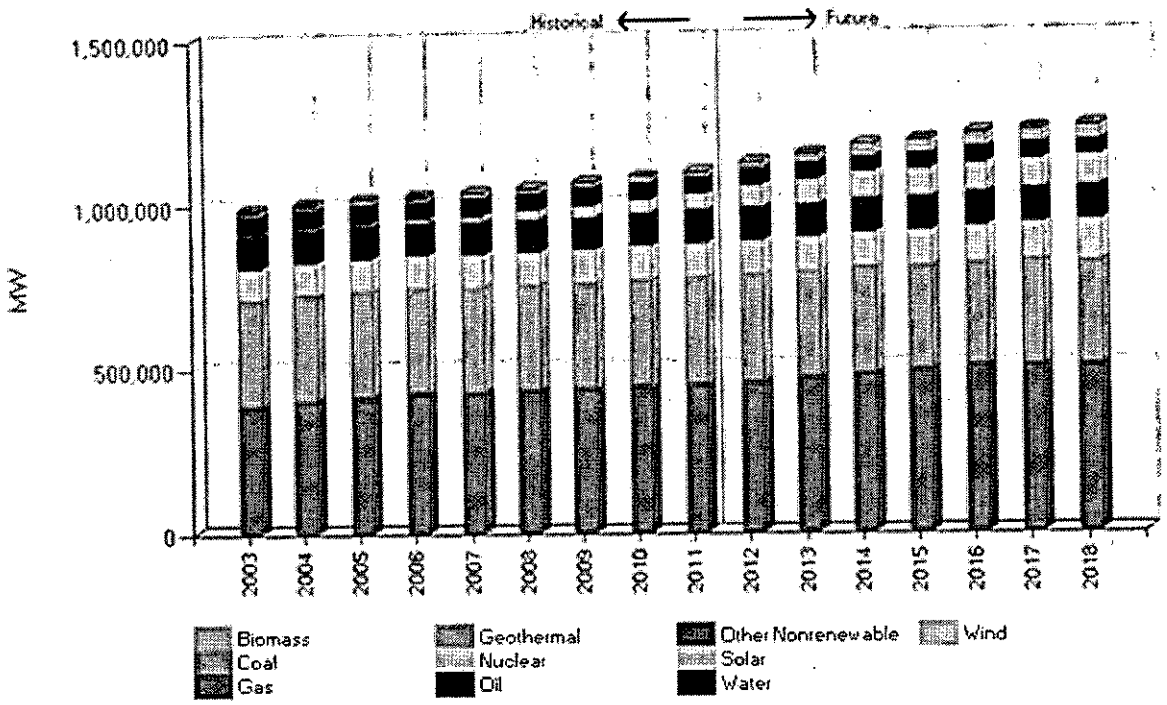
Growth of Installed Wind Power Capacity

Wind power comprised 25 percent of U.S. electric generating capacity additions in 2010. This is down from 42 percent in 2009, 43 percent in 2008, and 34 percent in 2007, but exceeds wind power's contributions in earlier years. In 2010, wind power was the third-largest new resource (behind natural gas and coal power plants) added to the U.S. electrical grid in terms of aggregate gross capacity, breaking a five-year streak in which wind power was second only to natural gas plants.

At the end of 2010, there were 258 GW of wind power capacity in the planning phase – more than six times current installed wind power capacity – that are administered by independent system operators, regional transmission organizations, and utilities. This wind power capacity represented more than 50 percent of all planned capacity additions within these queues at that time, and was more than twice as much capacity as the next-largest resource (natural gas). Most (91 percent) of this wind power capacity is planned for the Midwest, Mountain, Texas, PJM Interconnection, Northwest, and Southwest Power Pool regions. Projects currently in interconnection queues are often very early in the development process so much of this capacity is unlikely to be built as planned. Nonetheless, this data demonstrates a high level of developer interest in wind power.

The EIA's 2011 reference-case forecast projects that total U.S. electricity supply will need to increase at an average pace of roughly 41 terawatt hours ("TWh") (0.9 percent) per year from 2010 to 2035 in order to meet demand growth. On an energy basis, the annual amount of electricity expected to be generated by the new wind power capacity added in 2010 represents roughly 35 percent of this average annual projected growth in supply. By extension, if net wind power additions continued through 2035 at even the relatively slow pace set in 2010, then roughly 35 percent of the nation's projected increase in electricity generation from 2010 through 2035 would be met with wind electricity. Although future growth trends are hard to predict, it is clear that there are plans for a significant portion of the country's new generation needs to be met by wind.

Chart I
Historic and Future Power Plant Capacity
United States



Source: SNL Financial; Future capacity is based on actual planned/under construction projects, and not based on any projections of unreported new developments or retirements.

Table III
Historic and Future Power Plant Capacity in MW
United States

Type	2011	2012	2013	2014	2015	2016	2017	2018
Biomass	12,259.9	12,957.7	14,422.9	14,838.4	14,958.2	15,038.2	15,038.2	15,038.2
Coal	323,793.3	323,081.6	322,139.1	320,112.1	310,099.3	312,389.3	313,571.3	312,356.3
Gas	446,379.7	452,937.2	462,877.7	475,740.9	488,419.3	497,215.3	499,836.3	500,327.5
Geothermal	2,647.4	2,874.7	3,515.7	3,769.6	4,010.6	4,020.6	4,020.6	4,020.6
Nuclear	103,105.4	103,745.0	104,098.5	105,493.5	108,236.5	112,663.0	115,006.5	121,851.5
Oil	51,404.7	51,297.4	50,047.4	49,264.6	48,843.6	48,562.6	48,562.6	48,562.6

Type	2011	2012	2013	2014	2015	2016	2017	2018
Other Nonrenewable	4,484.7	4,599.7	4,734.7	4,734.7	5,834.7	5,834.7	5,834.7	5,834.7
Solar	1,873.3	4,463.7	9,849.4	15,641.9	19,626.8	22,557.8	23,057.8	23,957.8
Water	101,181.1	101,343.4	102,017.2	102,305.3	102,828.2	103,411.7	106,372.7	107,436.7
Wind	46,553.8	66,168.3	75,036.2	81,963.3	85,014.1	86,423.4	87,474.4	88,274.4
Total	**1,093,683.3**	**1,123,468.7**	**1,148,738.8**	**1,173,864.3**	**1,187,871.3**	**1,208,116.6**	**1,218,775.1**	**1,227,660.3**
Total Renewable	164,515.5	187,807.8	204,841.4	218,518.5	226,437.9	231,451.7	235,963.7	238,727.7
Renewable as % of Total	15%	17%	18%	19%	19%	19%	19%	19%
Wind as % of Total	4.3%	5.9%	6.5%	7.0%	7.2%	7.2%	7.2%	7.2%

Source: SNL Financial

Wind Project Costs

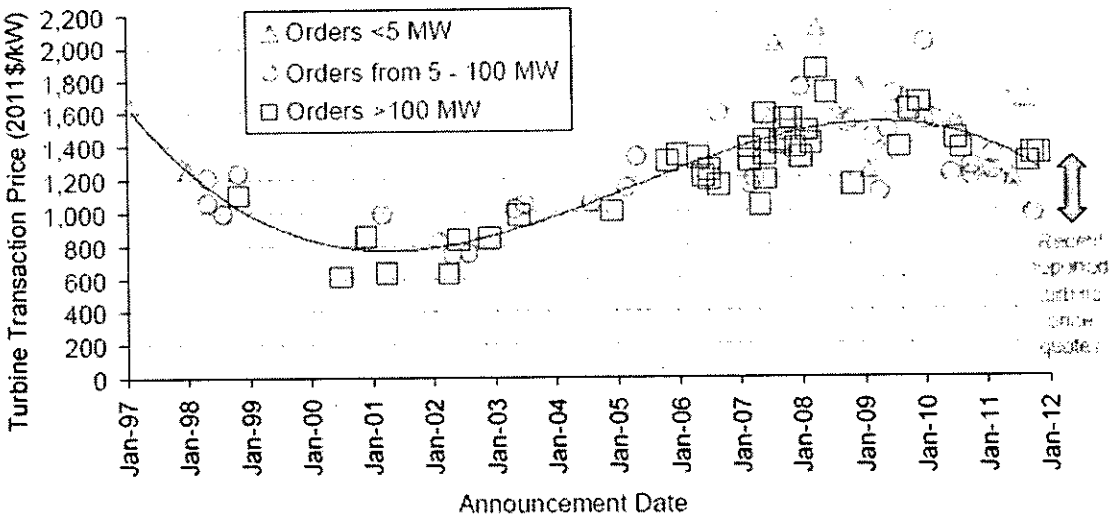
Turbine Costs

Wind turbine prices have dropped substantially in recent years, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters.

The Berkeley National Laboratory ("Berkeley Lab") has gathered price data for 96 U.S. wind turbine transactions totaling 26,600 MW announced from 1997 through 2011, including 12 transactions summing to 2,630 MW announced in 2011. After hitting a low of roughly $700 per kilowatt ("kW") of capacity from 2000 to 2002, average wind turbine prices increased by approximately $800 per kW (more than a 100 percent increase) through 2008, rising to an average of more than $1,500 per kW. The increase in turbine prices over this period was caused by several factors, including: a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy and labor input prices; a general increase in turbine manufacturer profitability due, in part, to strong demand growth and turbine and component supply shortages; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter.

However, wind turbine prices have declined substantially since 2008, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher, as well as increased competition among manufacturers and a shift to a buyer's market. As shown in Chart II, a number of turbine transactions announced in 2011 had pricing in the $1,150-$1,350 per kW range, while typical turbine prices in the U.S. in the first half of 2012 were reported by Bloomberg to be in the range of $900-$1,270 per kW depending on the technology. These figures suggest price declines of as much as 33 percent or more since late 2008, with an average decline closer to perhaps 20 percent for orders announced in 2011.

Chart II
Wind Turbine Costs
(Not Including Balance of Plant)



Source: Berkeley Lab

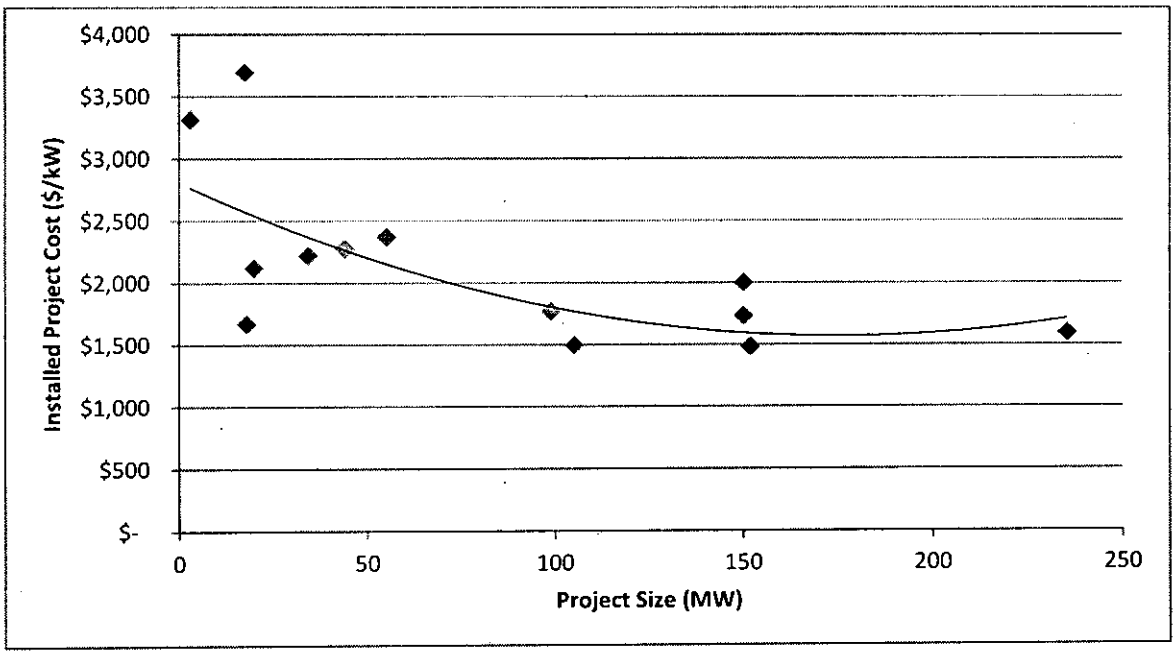
Moreover, these declines have been coupled with improved turbine technology and more-favorable terms for turbine purchasers (such as reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial operations and maintenance ("O&M") contract durations, improved warranty terms, and more-stringent performance guarantees). These price reductions and improved terms would be expected, over time, to exert downward pressure on total project costs and wind power prices.

Additionally, according to the Berkeley Lab, the average nameplate capacity of wind turbines installed in the U.S. doubled from 2001 to 2010. Along with this doubling in capacity, the average turbine hub height and rotor diameter also increased: hub height by 33 percent and rotor diameter by approximately 65 percent. These taller towers are not only taller, but also need to be wider and thicker to support the extra height. The rapid growth in turbine size has also impacted wind turbine prices on a dollar per kW of capacity basis. The fact that the capital cost of turbines can increase with size is widely understood, but the advantages in terms of lower balance of plant costs and higher levels of energy production typically outweigh those turbine price increases. The Berkeley Lab report states that increased rotor diameters and hub heights would be expected to improve capacity factors and further reduce wind power prices.

Installed Project Costs

The installed costs of wind power projects declined dramatically from the beginning of the industry in California in the 1980s through the early 2000s, but have more recently increased. In general, reported project costs reflect turbine purchase prices (discussed above) and installation, balance of plant, and any substation and/or interconnection expenses. However, installed project costs have shown signs of a potential plateau and reversal of recent increases. For example, the $2,155 per kW capacity-weighted average installed cost in 2010 was essentially unchanged from the $2,144 per kW seen in 2009; this $11 per kW (0.5 percent) increase was by far the smallest cost increase seen in the six years leading up to 2010.

Chart III
Installed Wind Project Costs (2010-2012 Projects)
(Including Balance of Plant; costs not trended)



In 2011, the capacity-weighted average installed project cost stood at nearly $2,100 per kW, down almost $100 per kW from the reported average cost in both 2009 and 2010. Moreover, a preliminary estimate of the average installed cost among a relatively small sample of 20 projects totaling 2.6 GW of capacity (that either have been or will be built in 2012) suggests that average installed costs may decline further in 2012, continuing to follow lower turbine prices.

Average installed project costs vary by region in the U.S., and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures. For projects that were installed from 2009 through 2011, the capacity-weighted average cost equaled $2,160 per kW nationwide over this period. Texas was the lowest-cost region, with installed project costs ranging from approximately $1,500 per kW to $2,600 per kW, while New England was the highest-cost region with installed project costs ranging from approximately $2,000 per kW to $4,500 per kW. All other regions came in close to the nationwide average.

On a global scale, Bloomberg analysts have cited the expectation that wind farms will be cost-competitive with a combined-cycle natural gas turbine by 2016. Buoyed by technology advancements and more competitive wind-manufacturing, the cost of wind energy is expected to continue to be pushed downward. Bloomberg analysts cited a long-term trend that showed a 7 percent cost reduction for the industry for every doubling of installed capacity.[2] Bloomberg went further to indicate that average turbine prices have fallen from €2.0 million per MW (€2,000 per kW) in 1984 to less than €0.88 million per MW (€880 per kW)

2. Andrew Engblom. "Bloomberg analysts project wind will reach fossil-fuel parity by 2016." *SNL.com*, 11 November 2011, http://www.snl.com/interactivex/article.aspx?id=13637732&KPLT=6 (accessed July 27, 2012).

in the first half of 2011 with capacity rising over that same period from 300MW to 240GW.[3] Furthermore, turbine output has been increasing as a percentage of nameplate capacity over the same period, up 13 percentage points to 34 percent.[4] At the same time, operations and maintenance costs have fallen approximately 78 percent since the 1980s. Operators have benefited from these lower costs but modernization of the turbines themselves has increased production. In the 1980s, each MW of wind capacity built on land could be expected to produce 1,800 MWh of electricity per year. Modern turbines can be expected to deliver 2,900 MWh per year.[5]

Power Purchase Agreements

Electric utilities are the dominant purchasers of wind power, either owning (25 percent) or buying (51 percent) of the power from 76 percent of the new capacity installed in 2011. Merchant/quasi-merchant projects were less prevalent in 2011 than they have been in recent years, accounting for 21 percent of all new capacity. Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracted and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 5- to 10-year period) rather than being locked in through a long-term PPA.

With PPAs in relatively short supply in comparison to wind developer interest, wholesale power prices at low levels, and a scheduled tax incentive expiration looming, it is likely that many of the merchant/quasi-merchant projects built in 2011 are merchant by necessity rather than by choice – i.e., building projects on a merchant basis may, in some cases, simply have been the most expedient way to ensure the deployment of committed turbines in advance of the scheduled expiration of important federal incentives (described further below).

The role of power marketers – defined here as corporate intermediaries that purchase power under contract and then re-sell that power to others, sometimes taking some merchant risk – in the wind power market has waned somewhat in recent years. In 2011, power marketers purchased the output of just 2 percent of the new wind power capacity, with 10 percent of the cumulative wind power capacity being sold to these entities.

Among the sample of wind power projects with PPAs signed in 2011 with publicly available pricing data, the capacity-weighted average levelized PPA price is $35 per MWh, down from $59/MWh for PPAs signed in 2010 and $72/MWh for PPAs signed in 2009. It is apparent that wind pricing has come down significantly in recent years, and is currently competitive with the range of wholesale power prices seen in 2011 according to data from the DOE.

Federal Incentives

Renewable Energy Production Tax Credit

Approximately 44 percent of all public or private U.S. energy investments in 2010 resulted from tax subsidies. One of these subsidies is the PTC, a per-kilowatt-hour Federal tax credit for electricity generated by qualified renewable energy resources and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by H.R. 1424 (Div. B, Sec. 101 & 102) in October 2008 and again by H.R. 1 (Div. B, Section 1101 & 1102) in February 2009.

The February 2009 legislation revised the credit by: (1) extending the in-service deadline for most eligible technologies by three years; and (2) allowing facilities that qualify for the PTC to opt instead to take the Federal investment tax credit ("ITC") or an equivalent cash grant from the U.S. Department of Treasury. The ITC or grant for PTC-eligible technologies is generally equal to 30 percent of eligible costs.

3. Ibid.
4. Ibid.
5. Ibid.

The tax credit amount is 2.2¢ per kilowatt-hour ("kWh") (equivalent to $22 per MWh) for wind facilities with an in-service deadline of December 31, 2012, and the duration of the credit is 10 years after the date the facility is placed in service. In addition, the tax credit is reduced for projects that receive other Federal tax credits, grants, tax-exempt financing, or subsidized energy financing. The PTC has spurred significant investment in wind power by directly lowering the cost of project development, thus allowing for an otherwise lower cost of power while still achieving a rate of return on the development projects that is adequate to attract investment. It was set to expire at the end of 2012. However, on August 2, 2012, the Senate Finance Committee passed a tax extenders package that included an extension of the PTC. Sen. Max Baucus, D-Mont., chairman of the committee, included the extension of the PTC and the ITC, which provides incentives for offshore wind development, in the chairman's mark of the Family and Business Tax Cut Certainty Act of 2012. The one-year extension (through 2013) must now go to the full Senate. If passed, the bill will go to the House of Representatives.

Without promises of an extension, wind development plans have subsided considerably, orders have dried up and large manufacturers are scaling back production or exiting the industry. However, IBISWorld expects that, despite the possible expiration of the PTC, demand for wind turbines will likely continue, on the back of other favorable incentives, strong interest in sustainable energy, and meeting RPS requirements. Increased interest in offshore wind is also expected to drive demand growth, as offshore wind farms continue to entice wind power developers. Furthermore, as noted by Bloomberg analyst Amy Grace, as a result of the aforementioned reductions in installed project costs, wind in the U.S. does not need the PTC subsidy to be competitive in the long term. However, in the near term "the industry will basically grind to a halt" without the extension of the PTC, with demand picking up again in 2014 and 2015 when renewable standards in some states require additional wind production.[6]

The importance of having a clear and predictable tax policy on U.S. renewable energy is demonstrated when tax incentives for wind projects have expired without the expectation of any extension. For example, when the PTC was terminated at the end of 2001 and not renewed until over a year later in March 2002, the uncertainty led to a 54 percent reduction in completed wind capacity in 2002 compared to 2001. Similarly, when the PTC expired in 2003 and was not renewed until October 2004, wind capacity fell 74 percent in 2004 compared to 2003.[7] A recent study has estimated that 8GW of capacity expected in 2012 could decline 75 percent to 2GW in 2013 if the PTC is not extended this year. The American Wind Energy Association estimates that wind capacity installations could be between 8GW and 10GW annually through 2016 should there be a four-year extension of the PTC.[8] The presidential election however only exacerbates the uncertainty over the expiration of the tax credits with nothing likely to happen before November. Those interested in doing deals in renewable energy are likely to try and put together deals before the expiration of the PTC.

Investment Tax Credit

The ITC was expanded significantly by the Energy Improvement and Extension Act of 2008 (H.R. 1424), enacted in October 2008. This law extended the duration -- by eight years -- of the existing credits for solar energy, fuel cells and microturbines; increased the credit amount for fuel cells; established new credits for small wind-energy systems, geothermal heat pumps, and combined heat and power systems; allowed utilities to use the credits; and allowed taxpayers to take the credit against the alternative minimum tax, subject to certain limitations.

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6 Andrew Engblom. "Bloomberg analysts project wind will reach fossil-fuel parity by 2016." *SNL.com*, 11 November 2011, http://www.snl.com/interactivex/article.aspx?id=13637732&KPLT=6 (accessed July 27, 2012).

7. Ashley Pipkin-Jones and Brian Collins. "Tax equity, Treasury cash grants: Investment trends in renewable energy." SNL.com, 29 February 2012, http://www.snl.com/interactivex/article.aspx?id=14307002&KPLT=6 (accessed July 27, 2012).

8. Ibid.

The credit for wind power developers is equal to 30 percent of expenditures, with no maximum credit for wind turbines placed in service after December 31, 2008. In general, credits are available for eligible systems placed in service on or before December 31, 2016. The American Recovery and Reinvestment Act of 2009 ("ARRA"), which allows PTC-eligible facilities to use the 30 percent ITC, enabled wind-energy systems of all sizes -- not only systems of 100 kW or less – to qualify for the 30 percent ITC.

Significantly, ARRA repealed a previous restriction on the use of the credit for eligible projects also supported by "subsidized energy financing." For projects placed in service after December 31, 2008, this limitation no longer applies.

Renewable Energy Grants

ARRA created a renewable energy grant program that is administered by the U.S. Department of Treasury ("Treasury"). This cash grant may be taken in lieu of the ITC.

Grants equal to 30 percent of the basis of the property are available to eligible wind facilities placed in service in 2009, 2010 or 2011 or placed in service prior to January 1, 2013, if construction began in 2009, 2010 or 2011. The guidelines included a "safe harbor" provision that sets the beginning of construction at the point where the applicant has incurred or paid at least 5 percent of the total cost of the property, excluding land and certain preliminary planning activities. (Only tax-paying entities are eligible for this grant).

New Hampshire Energy Market

New Hampshire is not an energy-intensive state; both total energy consumption and per capita energy consumption are among the lowest in the Nation. The transportation and residential sectors are New Hampshire's largest energy consumers. New Hampshire's residential electricity use is low compared with the national average, in part because demand for air-conditioning is low during the generally mild summer months and because few households use electricity as their primary energy source for home heating.

Although New Hampshire's total natural gas consumption is low compared to other States, demand has grown rapidly in recent years, particularly for use in electricity generation. The majority of the gas is supplied by pipelines entering the state from Maine and Canada. New Hampshire ships about one-half of the natural gas it receives to Massachusetts.

New Hampshire's net electricity generation is among the lowest in the Nation. Before 2003, the Seabrook nuclear power plant near Portsmouth provided more than one-half of the state's generation. Since then, however, that dominance has slipped somewhat as two new natural gas-fired power plants have come online. As in other New England States, the growing use of natural gas in New Hampshire's power industry has been driven by natural gas' lower emission levels compared with other fossil fuels and the ease of siting new natural gas-fired power plants. Natural gas-fired generation now accounts for about one-quarter of the state's power production.

The price of electricity in New Hampshire is currently well above the national average. According to data from the EIA, the average prices of residential, commercial, and industrial energy are 37.8 percent, 37.0 percent, and 80.1 percent higher than the national averages, respectively. As of May 2012, New Hampshire was ranked fifth among the fifty states ranked by high power prices.

New Hampshire also produces electricity from renewable energy sources, including wind, hydroelectric power, fuel wood, landfill gas, and municipal solid waste. Ten percent of New Hampshire's electricity generation is derived from these renewable sources.

The table below illustrates the current mix of historic and future power plant capacity in New Hampshire by fuel type. Future capacity is based on actual, reported planned/under construction projects, and not based on any projections of unreported new developments or retirements.

Table IV
Historic and Future Power Plant Capacity (MW)
New Hampshire

Fuel Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Biomass	156	162	163	152	152	227	244	244	244	244	244
Coal	580	580	576	595	595	595	595	595	595	595	595
Gas	1,470	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396
Nuclear	1,245	1,245	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247	1,247
Oil	530	528	528	528	528	528	528	528	528	528	528
Water	506	506	509	510	510	510	510	510	510	510	510
Wind	124	124	124	124	172	172	172	172	172	172	172
Total	**4,611**	**4,542**	**4,545**	**4,553**	**4,601**	**4,676**	**4,693**	**4,693**	**4,693**	**4,693**	**4,693**

Source: SNL Financial

New Hampshire's RPS, established in May 2007, requires the state's electricity providers -- with the exception of municipal utilities -- to acquire RECs equivalent to 24.8 percent of retail electricity sold to end-use customers by 2025. Due to the nature of the power pool, renewable and nonrenewable power cannot be traced from specific power plants to the power pool and back out to a specific customer. RECs provide the mechanism to track power generation from renewable resources. Each REC is a marketable/tradable security that represents one MWh of power generation from a renewable energy source. To comply with an RPS, electricity suppliers must purchase RECs to meet the minimum renewable percentages required by the RPS. If the electricity providers are not able to meet the RPS requirements by purchasing or acquiring RECs, they must pay penalties known as Alternative Compliance Payments ("ACP"). The 2012 alternative compliance payment prices vary by renewable energy sources, and is currently $64.02 per MWh for wind energy. Proceeds from the compliance payments are used to fund qualified renewable energy initiatives and projects. These penalties essentially create a ceiling on REC prices since utilities could always choose to pay the penalty should the price of RECs exceed the penalty price.

The New Hampshire Public Utilities Commission ("NHPUC") has established a REC program utilizing the regional generation information system of energy certificates administered by ISO-NE and the New England Power Pool ("NEPOOL"). RECs from customer-sited sources are assigned to the system owner, and behind-the-meter generation located in New Hampshire is eligible to participate in the RPS. Unused RECs from the prior two years may be used to meet up to 30 percent of a given year's compliance targets. Electric utilities may request to enter into multi-year contracts for RECs or electricity bundled with RECs to meet the RPS. Rural electric cooperatives may enter into multi-year contracts without NHPUC approval.

Generators must be sited within the New England control area, unless the source is located in a control area adjacent to the New England control area and the energy produced by the source is actually delivered into the New England control area for consumption by New England customers.

According to information obtained from the Database of State Incentives for Renewables & Efficiency ("DSIRE"), New Hampshire achieved 63.0 percent, 92.6 percent, and 87.9 percent of its RPS obligations in 2008, 2009, and 2010, respectively.

Given that the New Hampshire RPS does not require the purchased RECs to be associated with power generated within the borders of New Hampshire, but rather the New England control area (including the adjacent states of Maine, Vermont, Massachusetts, Connecticut and Rhode Island) the state could potentially meet its RPS requirements without the addition of new renewable energy projects within state borders. According to the NHPUC, New Hampshire's REC market and the regional REC market are inextricably linked not only with each other, but also with the REC market for New York, as a primary adjacent control area. The New Hampshire RPS, in its current structure, includes no requirements that favor New Hampshire providers of RECs over RECs that may come into New Hampshire from other states in New England and, with certain conditions, New York and New Brunswick, Canada.

According to the NHPUC, the current structure of the RPS in New Hampshire may create a "binary" market for RECs. In such a market, 1) the price of a REC rises to the amount of the ACP when demand for RECs exceeds supply, and 2) the price of a REC approaches zero when supply exceeds demand. The price ceiling of the ACP price results from market participants being unwilling to purchase RECs at a higher price than they would otherwise pay in the form of a penalty. Similarly, the price floor of zero exists due to the fact that excess RECs left over after each entity that must comply with RPS has satisfied their requirements have no value other than for banking for future compliance periods.

NHPUC data suggest that a downward trend in Class I REC prices from January 2008 through May 2011 indicates that there is currently a large regional supply of RECs relative to the demand for RECs, which suggests that New Hampshire electric service providers would not have difficulty purchasing RECs in the market and meeting their RPS obligations at reasonable costs. No providers made alternative compliance payments in lieu of purchasing Class I RECs in the most recent compliance period (2010).

However, forecasting future REC prices is problematic, given the intrinsic link between the New Hampshire market, the markets in the other New England States, and the New York market. Changes in the Connecticut and Massachusetts RPS policies are certain to affect the New Hampshire REC market, as those states comprise the largest loads for the ISO-NE. This has resulted in a wide range of expert views on future REC prices, with some experts predicting that REC prices may eventually fall to levels as low as $2.00 per REC, and others have predicting that prices will rise to reach the ACP, as the market goes through boom and bust cycles.

New Energy Development

Over the past five years, there have been seven renewable generation facilities completed in New Hampshire, as shown below. The last nonrenewable generation facility constructed in New Hampshire was the 800MW Granite Ridge natural gas-fired, combined cycle electric generating station located in Londonderry, New Hampshire, which was placed in operation in 2003.

Table V
Recently Completed Power Projects
New Hampshire

Power Plant	Plant Operator	Owner	City	Operating Capacity (MW)	Year First Unit in Service	Type
Colebrook Landfill	PPL Renewable Energy, LLC	PPL Renewable Energy, LLC	Colebrook	0.80	2010	Biomass
Ecoline Landfill Project	EMCOR Energy Services Inc	University of New Hampshire	Durham	4.60	2009	Biomass

Power Plant	Plant Operator	Owner	City	Operating Capacity (MW)	Year First Unit in Service	Type
Middleton	Middleton Building Supply, Inc.	Nancy Huot	Middleton	0.59	2008	Biomass
Middleton	Middleton Building Supply, Inc.	Lawrence	Middleton	0.59	2008	Biomass
Rochester Landfill Facility	SCS Energy LLC	University of New Hampshire	Rochester	3.20	2008	Biomass
Spaulding Avenue Industrial Complex	Tom Cusano	Tom Cusano	Rochester	0.30	2010	Hydro
Granite Reliable Power Windpark	Granite Reliable Power, LLC	Brookfield Renewable	Coos	99.00	2012	Wind
Lempster Mountain	Lempster Wind, LLC	Community Energy, Inc.	Sullivan	24.00	2008	Wind

Source: SNL Financial

In addition, all of the currently planned power projects in New Hampshire are renewable energy projects. The Seabrook nuclear power reactor, the largest in New England, provided 42 percent of New Hampshire's 2011 net electricity generation. The presence of such a large source of power has constrained the market appetite for larger, conventional power development.

Table VI
Power Projects under Development
New Hampshire

Project Name	Project Owner(s)	Planned Capacity (MW)	Status	Estimated Construction Cost($000)	Expected in Service Date	Fuel Type
Hopkinton Biomass	Diagnostic Inc	28.00	Announced	$150,000	-	Biomass
Manchester Solar Facility	Public Service Co. of NH	1.00	Announced	$10,000	-	Solar
Concord Industrial Park Project	Concord Steam Corp	17.00	Early Development	$80,000	2014	Biomass
Antrim Wind Energy Project	Antrim Wind Energy	30.00	Early Development	$65,000* *(Applicant's estimate is $55-$65 million)*	-	Wind
Clean Power Berlin Cogen Plant	Clean Power Berlin	26.10	Advanced Development	-	-	Biomass
Groton Wind Project	Iberdrola Renewables LLC	48.00	Construction Begun	$100,000	2012	Wind

Project Name	Project Owner(s)	Planned Capacity (MW)	Status	Estimated Construction Cost($000)	Expected in Service Date	Fuel Type
Berlin Biomass-Energy Project (Burgess BioPower)	Cate Street Capital, Starwood Energy	75.00	Construction Begun	$275,000	2013	Biomass

*Source: SNL Financial; Construction costs, aside from Antrim, estimated by SNL; *Antrim costs estimated by Applicant*

Clean Energy and Wind Power Investment

Compared to the first quarter of 2012, global clean energy investment rebounded 24 percent in the second quarter to $59.6 billion, although investment was still lower by 18 percent than investment during the second quarter of 2011. Wind and solar investment accounted for $21.6 billion and $33.6 billion in the second quarter, up 47 percent and 19 percent from the first quarter, respectively.[9]

China has led the way among individual countries with clean energy investments in the second quarter of $18.3 billion, up 92 percent from the first quarter. Hundreds of millions in financing have been secured for several of the large photovoltaic and wind projects in China. Public market investment in clean energy was almost double that of the first quarter at $1.2 billion, but 75 percent below the second quarter of 2011.

Venture capital and private equity investment in wind was off 28 percent from the first quarter at $1.5 billion.[10] One of the larger projects financed in the second quarter was the second phase of the 419-MW Flat Ridge Wind Farm in Kansas for $800 million that is jointly being developed by BP Wind Energy North America and Sempra U.S. Gas and Power, subsidiaries of BP plc and Sempra Energy, respectively, that is now in full construction.[11] There are approximately 110 wind projects that are currently under construction across the U.S. in the second quarter. Of those, seven wind projects are under construction in the northeastern U.S. (see Table VII), including a 48MW project in New Hampshire (Groton) expected to cost $120 million. The largest of these projects is Marble River, a 215 MW project in New York that is expected to cost approximately $475 million. Recent transactions of wind farms are presented in Table VIII.

9. Larry D'Alessandro. "Bloomberg analysts report rebound in clean energy investments." *SNL.com*, 11 July 2012, (accessed July 27, 2012).
10. Ibid.
11. Ibid.

Table VII
Wind Facilities Currently Under Construction
Northeastern U.S.

State	Project Name	Capacity (MW)	Turbine Rating	Turbine Manufacturer	Project Developer	Project Owner	Power Purchaser
MA	Equity Industrial Partners	4	2	Gamesa	Equity Industrial Turbines, LLC	Equity Industrial Turbines, LLC	City of Gloucester
MA	Hoosac	30	1.5	GE Energy	Iberdrola Renewables	Iberdrola Renewables	Nstar
ME	Bull Hill	34.2	1.8	Vestas	First Wind	First Wind	Nstar
NH	Groton	48	2	Gamesa	Iberdrola Renewables	Iberdrola Renewables	Nstar
NJ	Bayshore Regional Sewerage Authority (BRSA)	1.5	1.5	GE Energy	Bayshore Regional Sewerage Authority (BRSA)	Bayshore Regional Sewerage Authority (BRSA)	Not Disclosed
NY	Harbec Plastics	0.85	0.85	Gamesa	Harvest the Wind	Northern Developments, LLC	Not Disclosed
NY	Marble River	215.25	3	Vestas	EDP Renewables North America LLC	EDP Renewables North America LLC	NYSERDA/Merchant

Source: American Wind Energy Association

Table VIII
Recent Wind Facility Mergers and Acquisitions

Announce Date	Buyer	Target	Target State	Target NERC Region	Deal Value (Reported $000)
7/27/2012	Wisconsin Energy Corp.	Badger wind farm	WI	RFC	27,000
12/30/2011	Algonquin Power & Utilities	Four wind power projects	Various	Various	888,000
12/21/2011	Juhl Wind	Valley View power plant	MN	MRO	22,000
11/17/2011	Atlantic Power Corp.	Rockland wind	ID	WECC	12,500
9/13/2011	Edison Mission Group Inc.	Broken Bow Wind Farm	NE	MRO	8,036

Announce Date	Buyer	Target	Target State	Target NERC Region	Deal Value (Reported $000)
7/29/2011	Edison International	Crofton Hills wind farm	NE	MRO	4,500
5/24/2011	Duke Energy Corp	Shirley wind power facility	WI	MRO	47,700
4/28/2011	Juhl Wind	Woodstock Hills LLC	MN	MRO	100
4/8/2011	Edison International	Pinnacle wind force plant	WV	RFC	13,606

Source: SNL Financial; Includes only transactions with publicly available deal value

Industry Outlook

Total wind capacity in the U.S. is expected to grow 6.0 percent annually to 88.3 GW in the five years to 2017. Coupled with supporting legislation for renewables, utilities will continue to invest in wind power, along with other renewables, to meet demand expectations and new government requirements. However, the prospect of an extension of the Federal PTC after 2012 remains uncertain, limiting overall opportunity for wind to specific markets and locations with attractive characteristics for investors.

Underlying uncertainties about market and policy drivers have created some turmoil in the industry. On the positive side, the wind power industry benefits from some certainty on the available of Federal incentives for projects installed through 2012, and state policies have become more aggressive. Moreover, financing conditions have improved since 2009, and the availability of power purchase agreements has also begun to improve. With wind turbine prices having dropped, the recent trend of increasing project-level costs and prices will reverse.

On the other hand, with Federal tax credits slated to expire at the end of 2012, growth beyond 2012 is highly uncertain. Even before 2013, growth may continue to be negatively impacted by the limited need for new electric capacity additions to meet demand and RPS standards. With relatively low natural gas prices and reduced near-term price expectations, wind energy's primary competitor is more economically attractive than in previous years. The significant wind energy growth in recent years has also exceeded aggregate state RPS demands, resulting in softer incremental demand from RPS markets in the near term. Finally, wind energy is beginning to face stiff competition with solar in meeting state renewable energy requirements, as the cost of solar energy has declined substantially in recent years.

Impact Analysis

The following section summarizes the current and projected industry conditions that are likely to have a significant impact on the likelihood of the Project being financed and placed into commercial operation, as well as the risks it could be expected to face in achieving its financial goals.

Wholesale Electricity and Natural Gas Prices

The discovery and development of significant shale gas deposits, and the subsequent reduction in current and forecasted natural gas prices, has resulted in lower wholesale electricity prices throughout the U.S. The depressed price of electricity due to the glut of natural gas is putting the near-term comparative economic position of wind energy at risk.

According to data provided by SNL Financial, approximately 80 percent of net generation in New Hampshire in 2011 was provided by natural gas- and nuclear-fueled facilities, with 35 percent produced by natural gas fired facilities and 45 percent produced by nuclear fired facilities. Additionally, over half of

the power generated from New England power plants is derived from natural gas. With the combination of a significant amount of natural-gas fired generation in both the region and the state and low forecasted natural gas prices (and therefore wholesale electricity prices) wind projects economics are challenged.

Uncertain Regulatory Environment

The uncertainty surrounding environmental policy and regulations, which will affect the utility industry by requiring expensive retrofits of coal-fired facilities or possibly forcing plant retirements, is creating concerns that there could be power shortages in certain regions of the country once the programs are implemented.

While these regulations could benefit the wind energy industry in certain areas of the country, New Hampshire has demonstrated that it is capable of meeting its energy needs without the use of coal-fired facilities. To take advantage of plummeting power prices, PSNH has been taking its coal-fired Merrimack Station power plant offline frequently in recent months, replacing the energy generated from the 434 MW plant with cheaper electricity purchased on the open market.

On May 8, 2012, PSNH spokesman Mike Skelton stated, "The practice of not running Merrimack Station or any of our generation assets because we can purchase power more cheaply on the market is ongoing. It really can change week to week, or month to month, depending on our forecasts and what's happening in the market."

Given New Hampshire's lack of reliance on coal-fired generation, it is likely that the pending coal regulation would have a minimal impact on the ability of AWE to finance the Project.

Additional Capacity Requirements

Additional capacity will likely ultimately be needed in New England to meet RPS requirements. However, given the ability of New Hampshire electricity providers to purchase RECs from outside the state, it is difficult to predict the location and timing of additional capacity installations. Thus, it is likely that the renewable projects in New England that get completed will be those that are in specific markets and locations that offer attractive characteristics (i.e. acceptable returns and minimal regulatory and political hurdles) for investors.

Federal Incentives

Given the uncertainty surrounding the PTC's extension, a record or near-record number of wind installations are expected this year, as developers rush to take advantage of the PTC before it possibly disappears. Going forward, however, lenders may be unwilling to finance a project without certainty of the PTC's extension. According to the DOE, the currently-slated expiration of key federal tax incentives for wind energy at the end of 2012 threatens to dramatically slow new builds in 2013.

Additionally, many developers are not able to fully take advantage of the tax credits and benefits such as the PTC and ITC because they themselves are not profitable enough to benefit from the tax incentives nor have the tax liabilities that are compatible with the multi-year development, depreciation and cash-flow schedules of renewable energy projects. Therefore, developers must find investment partners with the income to benefit from the tax credits, and other tax attributes. There are over a dozen large entities (financial institutions and other corporate investors) and numerous smaller entities that have been active in tax equity investing in renewable energy.

However, given the pending expiration of the PTC at the end of 2012, the financing structure of the Project may not include tax equity.

Power Purchase Agreements

Wind PPAs are currently in relatively short supply in comparison to wind developer interest. It is likely that many of the merchant/quasi-merchant projects built in the U.S. in 2011 are merchant by necessity rather than by choice. However, we note that two PPAs have recently been signed in New Hampshire as shown in the table below.

Table IX
Recent PPAs Signed for New Hampshire Wind Projects

Power Plant	PPA Counterparty	PPA Contracted Start Date	Longest PPA Term (Years)	% of Nameplate Capacity Sold Under PPA
Granite Reliable Power Windpark	Central Vermont Public Service Corporation	4/1/2012	20	82.3%
Lempster Mountain	Public Service Company of New Hampshire	11/15/2008	15	90.0%

Source: SNL Financial

As stated by the Applicant in the Application, it is essential that a PPA be in place in order for a project to receive equity and/or debt financing. It is unlikely that a project finance investor would take on the risk of financing the project without a committed offtake agreement.

Renewable Energy Certificates

REC prices are a key determinant of whether new wind capacity is economically viable since utilities always have the option of buying power from the wholesale market or non-renewable sources and then purchasing RECs rather than entering into a PPA with a renewable project. However, forecasting future REC prices is problematic, given the intrinsic link between the New Hampshire and surrounding markets. This has resulted in a wide range of expert views on future REC prices, with some experts predicting that REC prices may eventually fall to levels as low as $2.00 per REC, and others have predicting that prices will rise to reach the ACP, as the market goes through boom and bust cycles.

This uncertainty may impact the ability to raise project financing.

Analysis of AWE Cash Flow Projections

The ability of the Project to attract the necessary capital to finance construction will be driven by its ability to generate an acceptable return on that capital. This, in turn, will be driven by the capital cost of the project, the revenue that it can generate, its useful life, and, to a lesser extent, operating expenses. Incentives such as the PTC and the ability of investors to realize tax benefits from accelerated depreciation are also important but are discussed in other sections of our report.

Project Capital Cost

The Applicant's estimated capital cost of the project is $55 to $65 million. The nameplate generating capacity of the project is expected to be 30 MW. Therefore the total cost of the project implies a cost of $1,800 to $2,000 per kW of capacity. In order to assess whether the estimated cost appeared to be within a reasonable or expected range, we compared it to costs of comparable facilities for which there was publicly-available data. We also compared it to estimates included in analyses prepared by the U.S. Department of Energy's National Renewable Technology Laboratory.

Comparison to Comparable Facilities

We compared this cost estimate with the cost indications from publicly-available sources presented in Chart III (presented earlier in this report) for wind farms installed in 2011 and 2012. Additional information for each of the seven plants is summarized in the table below:

Table X
Sample Installed Wind Project Costs
2010 - 2012

Project Name	Location	Capacity (MW)	Construction Cost	Construction Cost($/kW)
Broadview Wind Project	New Mexico	18.00	$30,000,000	$1,667
Bull Hill Wind Project (Blue Sky East)	Maine	34.20	$76,000,000	$2,222
Oak Glen	Minnesota	44.00	$100,000,000	$2,273
Pinnacle Wind Farm	West Virginia	55.20	$131,000,000	$2,373
Adams Wind Generation	Minnesota	19.8	$42,000,000	$2,121

Source: SNL Financial

For the five wind farms with capacities of between 15 MW and 60 MW (listed in Table VI above), the range of cost indications was approximately $1,600 to $2,400 per kW. The median cost of the above wind farms was $2,200 per kW and the average was $2,100 per kW.

The Applicant's estimated cost range is lower than the cost of all but one of the sub-60 MW projects represented in Table VI. Therefore, while we cannot say definitively that the Applicant's cost estimate is unrealistically low, it does appear to be 10 to 20 percent lower than comparably sized recent projects. The impact of a lower cost estimate from a financial analysis standpoint is that, all else equal, it would result in a higher estimate of the overall return on investment or higher net present value and therefore make the project look more attractive to investors relative to a higher cost estimate.

Comparison to National Renewable Energy Laboratory Analyses

In addition to analyzing the cost of comparable facilities, we also considered analyses prepared by NREL. In an April 2012 publication entitled 2010 Cost of Wind Energy Review (the "NREL Study"), NREL includes an analysis of the levelized cost of wind energy. The levelized cost is a measure of the life cycle costs of a power generation facility (installed capital cost, operating expenses, and financing costs) over the expected lifetime power output of the facility. As such, estimating the levelized cost of wind energy requires an estimate of the installed capital cost. In this study, NREL used a variety of sources including industry data and model projections to arrive at the best representative data for U.S. wind projects in 2010.

Based on a wind farm comprised of 1.5 MW turbines, NREL assumed a baseline installed capital cost of $2,155 per kW. The NREL Study notes that projects installed in 2010 had a wide range of installed capital costs ranging from $1,700/kW to $3,000/kW for "utility-scale wind farms." The study further notes that

there are many factors that can lead to differences in a project's capital cost. Because of these project-to-project capital cost fluctuations, NREL established best estimates using its proprietary model for each capital cost component, and then a market price adjustment was added to bring the all-in capital cost in line with the industry average. The market price adjustment accounted for fluctuations in component costs, profit margins, foreign exchange rates, supply chain constraints, and other market conditions. The report notes that it does not attempt to predict which capital cost components the market price adjustment influences, as it can vary drastically from one project to another.

It appears that relative to NREL's cost estimate and the observed cost range presented in the NREL Study, the Applicant's estimate is within the range although at the low end of the range. We note though that the NREL Study indicates that while installed capital costs for wind projects increased at a compound average annual growth rate of about 10 percent between 2004 and 2009, 2010 capital costs were generally unchanged from 2009, and preliminary 2011 estimates are down about 5 percent from 2010 to approximately $2,000/kW (the study references research by Wiser and Bolinger 2011).

Revenue

The two primary assumptions that drive revenue for a wind farm are the capacity factor and the price of energy generated by the wind farm. The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time. Therefore, the better the wind conditions at a site (in terms of frequency and velocity of wind), the higher the capacity factor and output of the project. The energy price will be determined by the price negotiated under a PPA. Typically PPAs for wind farms are priced so that the equity investor in the wind farm earns an acceptable rate of return on their capital based on reasonable assumptions for installed capital cost, operating performance, and financing costs. Therefore, a higher expected capacity factor would reduce the energy price required to provide an acceptable rate of return to an equity investor. The ability to offer a lower price would also make a project more attractive to potential offtakers.

Capacity Factor

In its financial modeling of the project, the Applicant assumes a capacity factor of [confidential material redacted] percent. The [confidential material redacted] percent capacity factor is based on a wind energy resource assessment prepared for Antrim by V-Bar. V-Bar estimated net capacity factors for the project as presented in the table below. The p-values in the table reflect the probability that a capacity factor would assume a value greater than or equal to the observed value strictly by chance. For example, a P-50 capacity factor of [confidential material redacted] percent indicates that, based on V-Bar's study, there is a 50 percent probability that the net capacity factor realized by the project will be [confidential material redacted] percent or greater.

Table XI
V-Bar Estimated Net Capacity Factors
2010 - 2012

[confidential material redacted]

Source: V-Bar, LLC

While we are not qualified to perform wind studies such as the study prepared by V-Bar, to assess the reasonableness of the capacity factor assumption, we compared it to capacity factors observed in other wind farms in the northeastern U.S. and New England specifically. This data presented in the tables below.

TableXII
Northeastern U.S. Wind Facility
2011 Annual Data

Power Plant	State	In Service Date	Nameplate Capacity (MW)	Capacity Factor (%)
Roth Rock Wind Project I	MD	2011	40.00	32.80
Hardscrabble (Top Notch) Wind Farm	NY	2011	74.00	23.45
Armenia Mountain Wind	PA	2010	100.50	29.31
Altona Wind Park	NY	2009	97.50	20.92
Chateaugay Wind	NY	2009	106.50	21.63
Wethersfield Wind Park	NY	2009	126.00	23.75
High Sheldon Wind	NY	2009	112.00	26.56
Cohocton Wind Farm I	NY	2009	87.50	21.45
Cohocton Wind Farm II	NY	2009	37.50	26.75
Locust Ridge II	PA	2009	102.00	22.92
North Allegheny Wind	PA	2009	70.00	26.19
Stony Creek Wind Farm	PA	2009	52.50	32.56
Highland Wind Project	PA	2009	62.50	58.75
Clinton Wind Park	NY	2008	100.50	19.81
Bliss Wind Park	NY	2008	100.50	21.68
Ellenburg Wind Park	NY	2008	81.00	23.67
Forward WindPower, LLC	PA	2008	29.40	22.89
Lookout WindPower, LLC	PA	2008	37.80	32.01
Munnsville Wind Farm	NY	2007	34.50	28.87
Maple Ridge	NY	2005	322.00	26.60
Max				58.75
Upper Quartile				28.98
Median				24.97
Mean				27.13
Lower Quartile				22.59
Min				19.81

Source: SNL Financial

Table XIII
New England Wind Facility
2011 Annual Data

Power Plant	State	In Service Date	Nameplate Capacity (MW)	Capacity Factor (%)
Record Hill (Roxbury) Wind Farm	ME	2011	25.30	17.51
Kibby Mountain Wind Project	ME	2009	132.00	24.08
Mars Hill Wind	ME	2007	42.00	34.67
Rollins Wind Farm	ME	2011	60.00	11.23
Stetson Mountain Wind II	ME	2010	25.50	26.75
Stetson Wind	ME	2009	57.00	30.91
Waymart Wind Farm	PA	2003	64.50	25.36
Searsburg Wind	VT	1997	6.00	23.77
Max				34.67
Upper Quartile				27.79
Median				24.72
Mean				24.28
Lower Quartile				22.21
Min				11.23

Source: SNL Financial

Compared to similar facilities in the northeastern U.S., the [confidential material redacted] percent capacity factor assumption is within the range of observed capacity factors, however, it is near the upper end of the range and well above the mean, median, and upper quartile of the data. However, only one of the twenty facilities in the sample had an observed capacity factor above 33 percent. Similarly, the [confidential material redacted] percent capacity factor assumption is significantly higher than the observed capacity factors of similar facilities in the New England region. The maximum observed capacity factor for the New England sample was approximately 35 percent, and the central tendency was closer to 25 percent.

In addition to comparing the estimated capacity factor with capacity factors for other wind farms in New England and the northeastern U.S., we also looked at capacity factor assumptions employed in the NREL Study. The NREL Study notes that because a wind farm's level of energy production is dependent on so many independent factors, it is typical to see varying capacity factors from wind farm to wind farm and from year to year within wind farms. A range of capacity factors from recent projects across the U.S. (based on research by Wiser and Bolinger 2011) is presented in the study. The range is from 25 percent to 45 percent. The baseline capacity factor selected for the NREL Study levelized cost analysis was 38 percent which is in line with the [confidential material redacted] percent estimate assumed by the Applicant. It should be noted also that the Applicant has indicated that the turbines that it plans to use for the project are larger than many turbines installed to date and are capable of achieving higher capacity factors than smaller turbines given identical site conditions. We were not provided with and are not aware of any analysis that quantifies what the improvement in capacity factor might be at a given site (including the supplemental prefiled testimony of Sean McCabe and Ellen Crivella and prefiled direct testimony of Ruben Segura-Coto on behalf of Antrim Wind Energy, LLC, dated August 22, 2012). As noted previously, we do not have expertise in assessing whether a certain turbine at a certain site is capable of achieving a

certain capacity factor. The purpose of this section is to illustrate that the capacity factor is an important driver of the economics of a wind farm and to provide comparative data from other wind farms in the same geographical area as the Project. This would be important as potential investors performed diligence on the Project.

Energy Price

As noted previously, energy sold under wind PPAs is typically priced so that equity investors earn an acceptable rate of return on their capital. Therefore, the acceptable price from an investor's standpoint will depend on operating assumptions (expected capacity factors, operating costs, and project life), financing assumptions (capital structure, cost of debt financing), the availability of incentives such as the PTC and the ability of investors to realize the economic benefits of such incentives as well as typical accelerated tax depreciation. In its base case analysis, the Applicant assumed an energy price of [confidential material redacted] per MWh over the life of the project. While this price assumes that all other assumptions are appropriate (including that the PTC will be available) and that this energy price results in an appropriate rate of return to investors, we performed an analysis to determine whether this price might be within an acceptable range for potential offtakers.

1. **Comparable PPA pricing** - We searched for publicly available information on pricing of recently signed PPAs in New England. While there is information available on signed PPAs, there is very limited pricing information such that we were not able to gather sufficient data to make this approach useful;

2. **Estimated "Proxy" PPA Pricing** - We prepared our own estimate of pricing of a "proxy" PPA based on current expectations for market energy prices, REC prices, and (less significantly due to low prices) Regional Greenhouse Gas Initiative ("RGGI") allowances. RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Together, these states have capped and will reduce CO2 emissions from the power sector by 10 percent by 2018.

   We estimated the market price that would accrue to a wind project located in the town of Antrim, in Hillsborough County, New Hampshire. The market price consists of the electricity sold to ISO-NE, the opportunity cost to buyers of not having to pay for CO2 emissions credits under the RGGI program, and the market value of RECs produced by the facility that could be sold to entities who need to satisfy their obligation to purchase RECs from the NEPOOL GIS, the regional registry of RECs.

Market Electricity Price

The forward price of on- and off-peak electricity delivered to a reference location in New England (ISO-NE Internal Hub) is available as an exchange-cleared over-the-counter (OTC) instrument. For purposes of this analysis the on- and off-peak prices were merged into an all-hours price. This price is quoted for about 18 months forward. Beyond that, the expected price is derived using the NYMEX-traded natural gas contract available through 2024 since there is a relationship between the prices of natural gas and electricity. The New England grid operator's market monitor uses the published spot price of natural gas and each generator's heat rate (the efficiency with which a power plant converts fuel into electricity) to verify that offers to supply electricity are competitively priced. A regression is used to project the forward price of electricity in the absence of market quotes.

Natural gas prices beyond 2024 were projected based on escalating the 2024 price at the risk-free rate. The NYMEX-cleared basis contract for gas deliveries to Algonquin city gate (southeastern Massachusetts) is quoted through 2016. Natural gas prices for Algonquin city gate beyond 2016 were projected using a regression analysis on the available market data. New England natural gas prices are

strongly affected by the development of natural gas supplies in western Pennsylvania and West Virginia. NYMEX-cleared forward basis contracts for natural gas deliveries to these locations are available through about 2019. That means that natural gas prices in New England are not expected to rise as quickly as the price of the natural gas NYMEX contract.

Using spot prices for natural gas and power in New England for the last five years we developed a regression that explains the clearing price of electricity as a function of season (as a surrogate for demand) and spot natural gas price. As noted above, the New England grid operator's market monitor uses the published spot price of natural gas and each generator's heat rate to verify that offers to supply electricity are competitively priced. The regression is used to project the forward price of electricity in the absence of market quotes.

RGGI Allowances

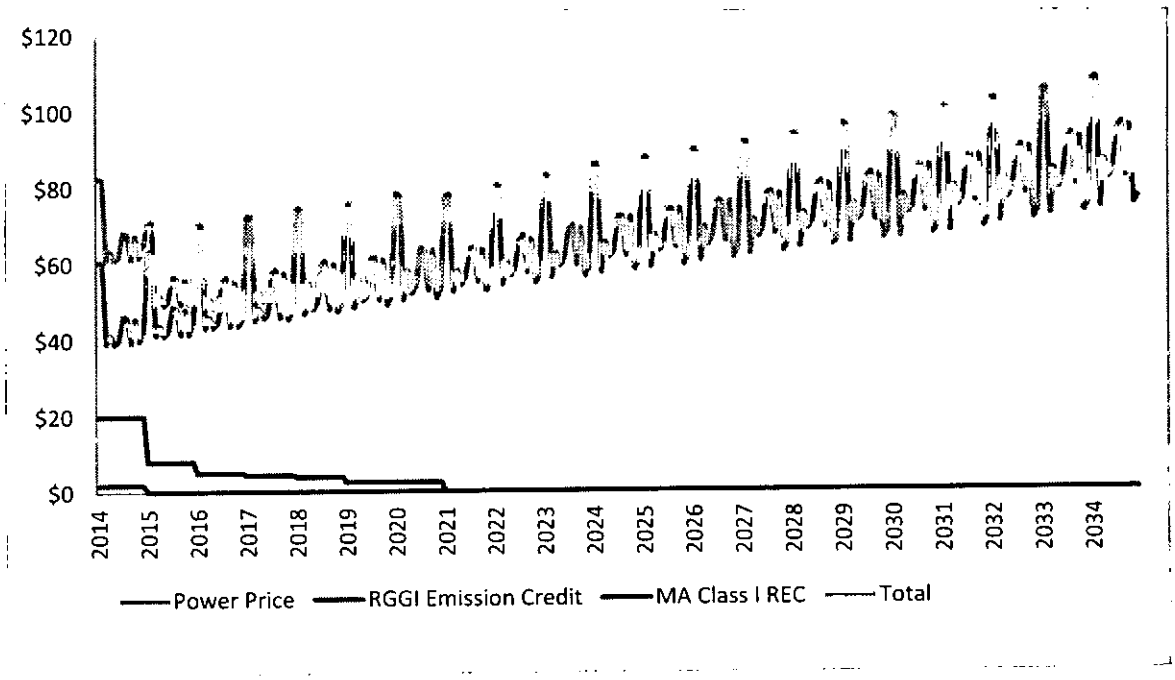
RGGI forward prices are based on NYMEX-cleared OTC transactions for these certificates. Beyond the period of time covered by the available market data the price is projected to remain extremely low. All indications are that the negotiated supply of emissions credits will exceed the demand for them. Because the existing rules allow for the unlimited banking of credits, the effect will be to dampen any future uncertainty in supply/demand equilibrium and strongly suppress prices.

Renewable Energy Certificates

We estimated an equilibrium price for New England RECs by examining the all-in cost of developing new wind facilities in the region. Due to the ongoing convergence of the New England renewables markets, this is a joint model for renewable prices throughout New England (Connecticut, Rhode Island, Massachusetts, New Hampshire and Maine) and is not unit specific. Long term equilibrium REC prices are estimated by assuming that new development will be needed at some point in the future, and that developers would require sufficient revenues to finance new wind projects. Two sources of revenue, wholesale power and RECs, provide potential income. The required cash flow to build a plant (assuming a desirable IRR) less any revenue received from wholesale power sales, determines the equilibrium price for RECs. The forward curve begins at the current price of Class I Massachusetts RECs and rises until equilibrium is reached. The speed at which prices move from current Class 1 Mass REC prices to equilibrium was estimated by an analysis of forecasted load growth in the New England Region. If regional demand returns to an average growth rate of 2 percent per year there will be REC shortages as soon as 2025.

Based on this analysis, we estimated an average hourly energy price over the 20-year life of the project. Although market power prices vary significantly throughout the day and the year as demand levels fluctuate, we believe that all hours average provides a reasonable estimate of an average price for energy from a wind farm since wind turbines cannot be stopped and started to take advantage of peak pricing and simply have to accept the market price available when the wind is blowing. The results are presented in Chart IV below.

Chart IV
Monthly Average Price Estimate



It should be noted that the monthly average prices spike during summer months when demand for electricity is higher, hence the volatile curve.

Based on the power price analysis presented above, the Applicant's estimated PPA price appears high relative to our estimates. We note that the price in the Applicant's analysis is a levelized price (i.e. it does not grow with inflation but is constant over the 20 year term). As our price estimate increases over time with inflation, we calculated the levelized price-equivalent of our estimated price curve. Using the unlevered, after-tax discount rate shown in the Applicant's baseline analysis, our projected prices (all-in price including energy, RECs, and RGGI allowances) are equivalent to a levelized price of approximately $65 per MWh. The [confidential material redacted] levelized price employed in the Applicant's baseline analysis therefore appears to be high relative to our levelized price estimate.

It should also be noted that (as reflected in a no-PTC scenario proforma analysis provided by the Applicant), if the PTC is not extended, the required levelized PPA energy price for Antrim would need to be approximately $22 per MWh higher than the [confidential material redacted] used in the PTC case. The higher price of approximately [confidential material redacted] per MWh would therefore be even higher than our estimate of an all-in market price of $65 per MWh.

We should note that this analysis was prepared in the absence of data on recent PPA prices and it provides a theoretical basis of estimating a PPA price for the Project that might be economically attractive to an offtaker given expectations for market power prices, REC prices, and RGGI allowance prices. It is important to note that while we prepared a point estimate of average monthly all-in prices, that there is a range of reasonable estimates. Any two participants in the market will likely have a different view on projected prices. REC prices, in particular, are very difficult to predict. The Applicant has indicated that it has knowledge of PPAs that have been recently signed in New England in the range of $90 to $100 per MWh. While we were not able to verify these prices, based on the Applicant's analysis, the Project would be economically viable with a PPA priced in this range, even without the PTC.

Useful Life

The Applicant made the assumption that the facility would operate for a 20 year useful life. Generally, the estimated useful life of a wind facility is assumed to be 20 years as the primary components (the turbines) are typically guaranteed for 20 years by the manufacturer. This is commensurate with the average term of PPAs signed for currently operating wind facilities of 19.7 years, based on information provided by SNL Financial. However, maintenance (including component replacement) can extend the useful life. Wind facilities are modular by their nature, and it is more likely that a change in the economics of electricity production, rather than the age of the facility, will end its useful life.

Operating and Maintenance Expenses

O&M costs are not the most significant component of the overall cost of wind energy, but can vary widely among projects, and market data on actual project-level O&M costs are not readily available. The AWE forecasted operating expenses are assumed to be approximately [confidential material redacted] per MWh of energy generated (or [confidential material redacted] per kW of capacity per year) in 2015 and increase thereafter at an inflationary rate of approximately 1.5 percent. These O&M expenses are higher than the average O&M cost for facilities installed between the years of 2000 – 2009 of approximately $10 per MWh, as reported in the NREL Study. Although the estimate is higher than average reported, it is still inside the range reported in the NREL Study of $4 per MWh to $30 per MWh.

Analysis of Financing Plan of Applicant

Deloitte Discussions with Financing Sources

In order to assess the financing terms of the Antrim project and the acceptability within the marketplace, we interviewed banks and finance companies about financing a wind project of the size and nature of the Project. None of the financing sources we spoke with considered the extension of the PTC in the financing terms provided to us. Discussions with the financing sources are grouped by type and are summarized below:

A) Foreign Banks. We held discussion with two foreign banks. Each institution had arranged or participated in over $1.5 billion in alternative energy transactions in the past twelve months.

   a. *Project Size.* The minimum project size that each bank typically finances is between 75 to 100MW although the banks did note that they would consider financing smaller transactions for active customers.

   b. *Pricing.* Financing terms could range from LIBOR plus 225bps to 300bps or fixed interest at 5.75 percent to 6.25 percent through a swap arrangement.

   c. *Amortization.* Assuming a 20 year PPA, amortization would be between 17 and 19.5 years with a balloon at the end of seven to nine years,

   d. *Capital Structure.* Given that PTC equity is unlikely (due to the anticipated expiration of the PTC), lenders would require 15 percent to 35 percent equity capital in a project, which is primarily driven by the Fixed Charge Coverage ratio.

   e. *Covenants.* Minimum Fixed Charge Coverage Ratio of 1.35x to 1.40x.

B) Finance Companies. We held discussions with two finance companies. Each company was active in small to mid-range wind projects providing sole-source financing.

a. *Project Size.* Size parameters for financing range from 8 to 50 MW projects,

b. *Pricing.* Financing terms could range from LIBOR plus 500bps to 600bps or fixed interest at 8.0 percent to 8.75 percent. A fixed rate will be offered as an alternative to a floating rate. A swap is not a requirement.

c. *Amortization.* Assuming a 20 year PPA, amortization would be between 15 to 19 years with a balloon at the end of 8 to 12 years,

d. *Capital Structure.* Given that PTC equity is unlikely, lenders would require 30 to 45 percent equity, although a mezzanine strip of 5 to 10 percent may be considered that would reduce the equity amount required in the project.

e. *Covenants.* Minimum Fixed Charge Coverage Ratio of 1.25x to 1.30x.

C) Regional Bank. We held a discussion with one regional bank that had executed one alternative energy transaction but expressed interest in additional opportunities.

a. *Project Size.* The size of the Antrim project would be acceptable to this particular bank although it would likely only hold $25 to $30 million, which would require the syndication of $10 to $20 million,

b. *Pricing.* Financing terms could range from LIBOR plus 300bps to 350bps with a corresponding fixed interest rate based on a swap arrangement.

c. *Amortization.* Assuming a 20 year PPA, amortization would be between 17 and 19 years with a balloon at the end of 7 to 8 years,

d. *Capital Structure.* Lender would require 30 percent to 35 percent equity.

e. *Covenants.* Minimum Fixed Charge Coverage Ratio of 1.35x to 1.40x.

Structure of Proposed Financing

The Applicant provided us two financing scenarios, one assuming the PTC is in place and the other assumes the PTC is not available. Given the uncertainty surrounding the extension of the PTC, we considered our analysis without the PTC. Based on the financial projection provided to us by the Applicant that assumes no PTC extension, the project financing need is approximately [confidential material redacted]. The Applicant has assumed a capital structure of approximately [confidential material redacted] percent equity with an assumed leveraged equity return of approximately [confidential material redacted] percent and approximately [confidential material redacted] percent debt at a cost of [confidential material redacted] percent. According to the Applicant, the project will generate a fixed-charge coverage ratio of [confidential material redacted] in the first year of operations. The table below summarizes the key terms of the projection scenarios we have reviewed from the Applicant.

Table XIV
Project Financing Terms Provided by Applicant

[confidential material redacted]

Financeability of the Antrim Project

While the above proposed terms provided by the Applicant for the non PTC case are outside of the parameters we observed through our discussions with the financing sources mentioned above with respect to the interest rate charged on debt financing and the percentage of equity required, we believe that the proposed terms should give the project enough room to absorb potential higher interest rates on debt financing and larger equity requirements and still meet the fixed charge requirements of the lenders cited above given the equity return projected to be available to equity investors in the project (i.e., over [confidential material redacted] percent) in the Applicant's financial model.

Given this and the fact that CP Energy Group LLC, a well-known capital advisory group in renewable energy, is assisting in the financing aspects of this project, it appears likely that the Antrim project can be financed if the Project can attract a PPA with pricing that allows for adequate return to investors. The financeability of the project is contingent on the project producing cash flows with a fixed charge coverage ratio of no less than [confidential material redacted], which is driven by the receipt of a qualified PPA at approximately [confidential material redacted] per MWh in combination with a capacity factor for the project approximating that stated by the Applicant. However, as noted in the prior section, based on our analysis and estimates of market prices for electricity, RECs and RGGI allowances, it may prove challenging to identify a PPA counterparty that is prepared to sign a PPA at a levelized energy price of [confidential material redacted] per MWh although the Applicant has advised that it has knowledge of PPAs that have been signed recently near this pricing level.

Evaluation of Development Team

The primary members of the development team for the Project, as provided in the Application, are presented in the table below. The remainder of this section discusses the experience of each of the primary team members.

Table XV
Project Development Team

Professional	Position	Company
Joseph E. Cofelice	Founder, CEO	Westerly Wind
Sean McCabe	VP of Development	Westerly Wind
Peter Mara	VP of Finance	Westerly Wind
Jack Kenworthy	Founder, CEO	Eolian
John Soininen	VP of Development	Eolian

We performed some background screening procedures on the team members listed in the table above using a number of databases that collect publicly-available information on individuals. This background screening included the following:

- Regulatory/Sanctions - We reviewed available online files containing disciplinary actions and sanctions collected from various federal and state agencies, as well as the Office of Foreign Assets Control's master list of blocked individuals/entities, for any records naming the entities or requested individuals. No records were located.

- Federal Litigation - We conducted online searches in U.S. District Courts nationwide for any records naming the entities or requested individuals. No records were located.

- Bankruptcy - We conducted online searches of available bankruptcy records nationwide for any records referencing the entities or requested individuals as debtors. No records were located.

- Liens and Judgments - Available federal and state tax liens and county-level judgment records were searched online nationwide for any records referencing the entities or requested individuals as debtors. No records were located.

- Adverse Media - A review of online media from numerous sources including newspapers, magazines, trade and industry journals, broadcast transcripts, general Internet sites, and wire services was conducted for any negative references to the entities or individuals. We found the following:

    - An article from The Keene-Sentinel (New Hampshire) on June 19, 2012 reported that several Antrim, New Hampshire residents have claimed that Antrim Wind Energy, LLC conducted secret meetings with the town Board of Selectmen regarding a PILOT (Payment in lieu of taxes) agreement. The residents claim that the agreement should not stand because it was made without proper public notice. Antrim Wind CEO, Jack Kenworthy, confirmed that these meetings occurred at a public meeting in April, 2012. According to the article, "the group of residents say that aside from being negotiated during illegal meetings, it is still uncertain such an agreement is in the town's best interests." Reportedly, under the 21-year contract, Antrim Wind would pay $11,250 per

megawatt for the first year the facility is open, and the rate would increase 2.5 percent per year thereafter.

- An article from the Sentinel Source on August 9, 2012 reported that a lawsuit has been filed at the state/local level against Antrim Wind Energy LLC in New Hampshire on June 30, 2012. According to the report, the lawsuit states that "the conscious decision to exclude the public and to meet in secret rendered the Nov. 30 and June 20 public hearings meaningless," and asks that the Hillsborough County Superior Court invalidate the PILOT agreement that was approved on June 20. The lawsuit against Antrim's board alleged violations of New Hampshire's Right to Know law.

- An article from The Orleans County Record on May 31, 2012 reported that a Newark, Vermont resident filed a complaint with the Vermont Agency of Natural Resources alleging a concern that Eolian Renewable Energy was potentially constructing roads and clearing land for a future wind turbine site under the premise that the roads were being constructed for logging purposes. According to the article, Jack Kenworthy denied that any work was being done on behalf of Eolian, although the article did report that the company had requested the development of meteorological towers in the area.

Based on this screening, we did not identify any information that reflects negatively on the character of any of the team members or on their ability to develop the project. The articles noted above are included for completeness but do not appear to provide evidence that any of the team members lacks the professionalism, character, and ability to play his role in development of the Project.

The remainder of this section discusses the experience of each of the primary team members. Unless otherwise noted, the professional biography information provided below was provided by the applicant.

Joseph Cofelice

Executive Officer of AWE; Founding Member and CEO of Westerly Wind, LLC

Prior to forming Westerly in 2010, Mr. Cofelice was President of Catamount Energy Company, a Vermont-based independent power company focused on wind energy. While Mr. Cofelice was President of Catamount, the company successfully permitted projects in the UK and developed, financed, constructed and operated five phases of the Sweetwater, TX wind project using industry standard tax equity and lending structures totaling over $1 billion in the aggregate. The following table details projects in which Mr. Cofelice was involved in the development, financing, construction, ownership and operations.

Table XVI
Joseph Cofelice Projects

Project/Location	Capacity (MW)	Turbine Technology	Commercial Operation Date
Sweetwater 1 Nolan County, Texas	37.5	GE 1.5-MW	Dec 2003
Sweetwater 2 Nolan County, Texas	91.5	GE 1.5-MW	Feb 2005
Sweetwater 3 Nolan County, Texas	135.0	GE 1.5-MW	Dec 2005
Sweetwater 4 Nolan County, Texas	135.0 105.8	Mitsubishi 1-MW Siemens 2.3-MW	May 2007

Project/Location	Capacity (MW)	Turbine Technology	Commercial Operation Date
Sweetwater 5 Nolan County, Texas	80.5	Siemens 2.3-MW	Dec-07
Top of the World Converse County, Wyoming	101.2 99.0	Siemens 2.3-MW GE 1.5-MW	Oct-10
Laurel Hill Lycoming County, PA	69	Siemens 2.3-MW	Under construction
Total	854.5		

Source: Applicant

Additionally, the following transactions were completed during Mr. Cofelice's tenure at Catamount.

Table XVII
Catamount Transactions

Closed Date	Transaction Type	Role	Target	Buyer/Investors	Sellers	Size ($millions)
Mar-27-2009	Merger/Acquisition	Seller	Mark Hill Wind Power	ScottishPower Renewables (UK) Ltd.	Catamount Energy Corporation	Not disclosed
Nov-12-2008	Merger/Acquisition	Seller	Catamount Cymru Cyf	Statkraft UK Ltd.	Catamount Energy Corporation	Not disclosed
Sep-15-2008	Merger/Acquisition	Target	Catamount Energy Corporation	Duke Energy Corporation (NYSE:DUK)	Diamond Castle Holdings, LLC *Seller Funds:* Diamond Castle Partners Fund IV, L.P.	325.00
Mar-09-2007	Merger/Acquisition	Buyer	EPG Fuel Cell, LLC.	Catamount Energy Corporation	Elemental Power Group, LLC	Not disclosed
Jul-31-2006	Merger/Acquisition	Seller	Sweetwater 3 Wind Farm Project	Babcock & Brown Wind Partners Group (nka:Infigen Energy (ASX:IFN))	Catamount Energy Corporation	Not disclosed
Dec-20-2005	Merger/Acquisition	Target	Catamount Energy Corporation	Diamond Castle Holdings, LLC	Catamount Resources Corporation	59.25
Oct-31-2005	Private Placement	Target	Catamount Energy Corporation	Diamond Castle Holdings, LLC		16.00
Oct-21-2004	Merger/Acquisition	Seller	EPR Thetford Limited	Fibrowatt Limited	Catamount Energy Corporation	Not disclosed
Jul-07-2004	Merger/Acquisition	Seller	Catamount Energy Corp., Two 10 Megawatt Natural Gas Fired Facilities	Tierra Energy, LLC	Catamount Energy Corporation	Not disclosed
Nov-08-2002	Merger/Acquisition	Buyer	Heartlands Power Limited	Catamount Energy Corporation	Rolls-Royce Power Ventures Limited	Not disclosed

Source: Capital IQ

Catamount was a portfolio company of Diamond Castle Holdings. Mr. Cofelice left Catamount upon the sale of the business to Duke Energy in September 2008. The Applicant stated that, as a result of the

acquisition of Catamount by Duke Energy, there was an understanding that Mr. Cofelice and other senior management of Catamount would not remain with the company after the acquisition. This was a voluntary agreement made by Mr. Cofelice.

Prior to Catamount, Mr. Cofelice was CEO of American National Power ("ANP"), a U.S. based independent power subsidiary of London based International Power Plc. Mr. Cofelice spent over 15 years at ANP and was at various times directly responsible for all aspects of the business including project development, project financing and marketing & trading. While at ANP, Mr. Cofelice was responsible for the development, financing, construction and operation of natural gas combined cycle power plants with a total capacity of approximately 3,850 MW.

Mr. Cofelice also served in various accounting, finance and oil and gas marketing roles for Shell Oil Company and Enron Oil & Gas.

During our review of the Application, we held a number of discussions (via telephone) with Mr. Cofelice and other members of the development team. During these discussions, Mr. Cofelice demonstrated an appropriate level of understanding of the Project and key considerations in project finance.

Sean McCabe
Executive Officer of AWE; Founding Member and Vice President of Development of Westerly Wind, LLC

Mr. McCabe has worked in the wind industry since 2004. He has experience at both an independent power producer and a large utility: His key roles were as follows:

Managing Director - Wind Development, Duke Energy Corporation

- Developed Top of the World Windpower Project, a 200 MW operating wind facility, from site origination through permitting/offtake.
- Managed $2 million development budget to advance six wind projects in Duke's pipeline

Vice President - Finance and Development, Catamount Energy Corporation

- Formulated strategy to identify and secure wind energy development sites in the U.S.
- Executed on development strategy: educated stakeholders on wind energy benefits and impacts; negotiated and secured land leases; led local, state and federal permitting efforts; and managed development studies and interconnection requests.

Peter Mara
Executive Officer of AWE; Vice President of Finance of Westerly Wind, LLC

Mr. Mara has eight years of energy industry experience across several disciplines in energy finance, including, mergers and acquisitions, infrastructure and project finance, utility bond research, and portfolio management. His key roles were as follows:

Associate, U.S Renewables Group

- Assisted in analyzing, structuring and closing of new investments, ongoing portfolio management, and fundraising

Associate, Infrastructure, Project and Corporate Finance Group, John Hancock Financial Services

- Assisted in the debt restructuring and sale of secured notes in an approximately 39MW wind project in West Texas.
- Assisted in the purchase of equity interests in an approximately 275MW combined cycle natural gas fired power plant located in Western Massachusetts.
- Assisted in structuring and closing of an $18M debt financing consisting of senior and subordinated loans into three landfill methane projects in Virginia and North Carolina.
- Assisted in structuring and closing of a $50M debt financing consisting of senior and subordinated loans in two landfill methane projects in Pennsylvania.
- Assisted in forming a joint venture and investing private equity capital in three power plants including: a 830MW natural gas combined cycle power plant in Texas, a 1,409 MW natural gas peaking power plant in Illinois, and a 795 MW natural gas combined cycle plant in Oklahoma.
- Assisted in a private placement of New York hydro assets consisting of 74 power plants representing approximately 730MW of nameplate capacity.

Jack Kenworthy
Executive Officer of AWE; CEO of Eolian Renewable Energy, LLC

Mr. Kenworthy is responsible for the overall management of Eolian's wind development portfolio, as well as managing the company's strategic growth.

Prior to founding Eolian, Mr. Kenworthy was CEO at Cape Systems, Limited– a renewable energy consulting and development firm based in The Bahamas. During Mr. Kenworthy's tenure, the company negotiated the first grid interconnected renewable power installations in The Bahamas. The company also launched the first commercial scale biodiesel production facility in the region in partnership with Bahamas Waste.

Prior to Cape Systems, Mr. Kenworthy was a founder and Director of Systems at Cape Eleuthera Institute, a non-profit marine science and sustainable development research hub in the Caribbean. Mr. Kenworthy was responsible for the design, funding and construction management of the 18 acre facility which featured innovative green buildings, 100 percent renewable power systems (solar, wind, biodiesel), bio-remediation of waste water systems and integrated food production systems.

Based on our own research, Mr. Kenworthy initially moved to the Bahamas in 2000 to work as a science teacher at the Island School. The Island School began as a 22 student, six faculty member school in 1999. Seven years later, students at the school came from over 160 institutions across the U.S., Canada, and the Bahamas. According to one article, Mr. Kenworthy was a key person in developing educational and physical infrastructure at the school around sustainability, including wind, solar and hybrid energy, recycled building materials, and a wetlands system for wastewater treatment.

According to the article, once these programs were up and running, Kenworthy started a laboratory to turn waste vegetable oil from the cruise ships that stopped at Eleuthera—some 150 each year—into biodiesel fuel. Due to the prospect of growth in adjacent islands, the Island School, a non-profit corporation, spun off a for-profit subsidiary, Cape Systems, in 2003.

However, we note that we have not independently verified information available about the Cape Eleuthera Institute or other aspects of Mr. Kenworthy's Bahamas business background.

John Soininen
Executive Officer of AWE; Vice President of Development of Eolian Renewable Energy, LLC

Mr. Soininen has been involved in the management of development projects for his entire professional career.

Prior to Eolian, Mr. Soininen worked for Windermere Island North Development, Ltd., which owned and was redeveloping the Windermere Island Club on the island of Windermere just off the coast of Eleuthera, Bahamas. He was the development manager and construction manager for the project

Prior to Windermere, Mr. Soininen worked for Leggatt McCall Properties in Boston, Massachusetts. In his most recent role he was a Senior Development Manager and oversaw the development of the One First Condominium Complex in East Cambridge.

Prior to managing the One First project, Mr. Soininen was the project manager for what is now the Fairmont Battery Wharf Hotel in Boston.

Summary

Based on the information provided to us by the Applicant and through our independent research, we note that several members of the development team have direct project development and finance experience, including the development of comparable wind facilities. Key members of the development team have experience in the power industry in general and in renewable energy specifically. We did not find any information that would negatively impact our conclusion that the team appears to be qualified to develop the Project and that specific team members are not capable of performing their roles.

Mr. Cofelice appears to have significant experience in the power industry generally, in renewable energy specifically, and in leading teams and organizations involved in development of projects and in transactions. As such, he appears to have an appropriate level of experience to lead a team in developing the Project.

Based on his experience, Mr. McCabe appears to have some experience in developing wind projects over the past eight years, including a relatively large one. We did not find evidence to suggest that he is not capable of competently performing his role as Vice President of Development.

Mr. Mara appears to have some experience in financing wind projects over the past eight years. We did not find evidence to suggest that he is not capable of competently performing his role as Vice President of Finance.

Based on our understanding of Mr. Kenworthy's role in Cape Systems, as presented in the above-mentioned article, it appears that he demonstrated a significant level of entrepreneurial spirit in developing the projects that he was involved with in the Bahamas although the projects appear to be on a smaller scale than the Project. Based on the representations made in the article, it appears however that he has the ability to lead in developing greenfield projects and could complement the more direct experience of other members of the Project team. However, we note that we have not independently verified information available about the Cape Eleuthera Institute or other aspects of Mr. Kenworthy's Bahamas business background.

Based on the information presented to us, Mr. Soininen has experience in development of projects although the majority of this experience appears to be in development and project management for residential and commercial real estate. Based on the information available to us, he does not appear to have experience in developing power generation assets or wind projects specifically.

Summary of Findings

Market Assessment

In recent years, investment in wind power has grown significantly, spurred by federal and state tax incentives and state RPS. Going forward, the ability to develop new wind projects will depend, to a large extent, on the ability of developers to sign PPAs with offtakers at prices that provide an acceptable rate of return to the investors in the project. PPAs are in short supply relative to demand as low gas (and therefore electricity) prices and low REC prices have made it less expensive for utilities to meet RPS without entering into PPAs with owners of renewable projects or buying/developing such projects themselves.

In addition, the currently planned expiration of the PTC at the end of 2012, will put additional pressure on the economics of wind projects as, all else equal, PPA prices will need to increase to provide acceptable rates of returns to investors. Even if the PTC is extended, the availability of tax equity financing (i.e. financing from equity investors with sufficient taxable income to be able to take advantage of the PTC and other tax benefits) is low.

Due to these factors, a significant decrease in wind installations is expected in 2013. However, IBISWorld expects that, despite the possible expiration of the PTC, demand for wind turbines will likely continue, due to other favorable incentives, strong interest in sustainable energy, and state RPS requirements. In addition, forecasting future REC prices is difficult, especially in New Hampshire, given the intrinsic link between the New Hampshire market, the markets in the other New England States, and the New York market. Changes in the Connecticut and Massachusetts RPS policies are certain to affect the New Hampshire REC market, as those states comprise the largest loads in ISO-NE. This has resulted in a wide range of expert views on future REC prices.

Project Business Plan Assessment

In general, the Applicant had a reasonable basis for its estimate of the capital cost, revenue expectations, operating costs, and economic useful life of the Project. We made high-level comparisons of key assumptions based on publicly-available data on the cost and operating performance of other wind power projects and on assumptions made by NREL in its economic analysis of wind power projects. In the absence of sufficient publicly-available data on recent PPA prices for wind projects, we also prepared an analysis to estimate an "all-in" market price that potential offtakers might consider as an alternative to signing a PPA with the Project.

The Applicant's assumptions were generally within ranges observed for comparably-sized projects in New England and were in line with assumptions made in NREL's analyses. We highlight two specific assumptions with respect to the revenue forecast for the Project, which we believe would lead a potential investor to execute additional due diligence:

> **Capacity factor** – The capacity factor (electricity production level relative to Project capacity) appears to be high relative to comparably-sized projects in New England. This assumption is an important driver of project economics. By way of explanation, the Applicant has indicated that the large turbines that it plans to use are capable of achieving higher capacity factors at a given site than the more commonly used small turbines and has provided a wind study supporting the assumption. We are not qualified to assess the reasonableness of this assumption but have merely provided comparisons for informational purposes as we believe it would be important in developing a full understanding of the project economics.
>
> **PPA price** – The required PPA price to achieve satisfactory project economics (especially if the PTC is not available) is higher than our estimate of an "all-in" market price (i.e. for electricity and

RECs) that potential offtakers might consider. However, estimates of future "all-in" prices vary widely, especially due to the difficulty in projecting REC prices. In addition, forecasted prices may not be representative of a price forecast relied upon in setting PPA price levels. To that end, the Applicant has indicated that it is aware of wind PPAs that have been signed recently at prices that are supportive of its pricing assumptions. We were not able to verify this based on publicly-available data since there is little data available on PPA pricing.

Funding Plan Assessment

While the proposed terms provided by the Applicant for its non PTC case are outside of the parameters we observed through our discussions with financing sources active in the wind power market, we believe that the proposed terms should give the project enough room to absorb potential higher interest rates and larger equity capital requirements and still meet the fixed charge requirements of lenders. It is suggested, however, that a projection scenario that requires a capital structure of [confidential material redacted]percent equity (required equity return target of [confidential material redacted] percent) and [confidential material redacted] percent debt (cost of debt of [confidential material redacted] percent) be analyzed by the Applicant in order to determine that a minimum of a [confidential material redacted] fixed charge coverage ratio can still be achieved. Notwithstanding the market observations from our discussions with the financing sources, we understand that Antrim is in discussions with a financial institution that is seeking debt yields and fixed charge coverage ratios consistent with the projections provided to us by Antrim.

Given this, and the fact that CP Energy Group LLC, a well-known capital advisory group in renewable energy, is assisting in the financing aspects of this project, it appears likely that the Antrim project can be financed if the Project can attract a PPA with pricing that allows for adequate return to investors. The financeability of the project is contingent on the project producing cash flows with a fixed charge coverage ratio of no less than [confidential material redacted], which is driven by a qualified PPA at approximately [confidential material redacted] per MWh in combination with a capacity factor approximating that stated by the Applicant.

Development Team Assessment

Based on the information provided to us by the Applicant and through our independent research we note that the majority of the development team has direct experience in wind and other power project development and financing. Based on additional research, which included searches of a number of proprietary databases that we subscribe to, we did not find any information that would negatively impact our conclusion that the team appears to be qualified to develop the Project.

Closing Remarks

All results, advice, recommendations, or conclusions included in this report are subject to the Assumptions and Limiting Conditions that are presented as appendices.

The following appendices and exhibits provide more detailed information regarding the analysis described in this report:

- Appendix 1 — Assumptions and limiting conditions
- Appendix 2 — Professional biographies of principal consultants

We have no obligation to update this report for information that comes to our attention after the date of this report.

If you have any questions regarding the results of the analysis, please contact Keith Adams at 404-631-3455 or Paul Warley at 404-220-1331.

Respectfully submitted,

Deloitte Financial Advisory Services LLP

Appendices

Appendix 1 — Assumptions and Limiting Conditions

This report has been prepared pursuant to the following general assumptions and general limiting conditions:

1. The analyses, advice, recommendations, opinions, or conclusions contained herein are valid only as of the indicated date and only for the indicated purpose.

2. The analyses, advice, recommendations, opinions, or conclusions contained herein are for the exclusive use of the Client for the sole and specific purposes noted herein and may not be used for any other purpose by the Client or any other party. Furthermore, the analyses, advice, recommendations, opinions, or conclusions are not intended by the author and should not be construed by the reader to be investment advice in any manner whatsoever. The analyses, advice, recommendations, opinions, or conclusions represent the considered opinion of Deloitte Financial Advisory Services LLP ("Deloitte FAS") based on information furnished to it by the Client, its representatives, and other sources.

3. Possession of this report, or a copy thereof, does not carry with it the right of publication or distribution to or use by any third party. Any third party that uses the information contained herein does so at its sole risk and agrees to hold Deloitte FAS, its subcontractors, and their respective personnel harmless from any claims resulting from use by any other third party. Access by any third party does not create privity between Deloitte FAS and any third party.

4. No part of the contents of this report (especially the analyses, advice, recommendations, opinions, or conclusions; the identity of any Deloitte FAS personnel, or any reference to any of their professional designations or to Deloitte FAS) should be disseminated to the public through advertising media, public relations, news media, sales media, mail, direct transmittal, or any other means of communication without the prior written consent of Deloitte FAS.

5. No item in this report shall be changed by anyone other than Deloitte FAS, and Deloitte FAS shall have no responsibility for unauthorized changes.

6. Neither Deloitte FAS nor its personnel, by reason of this engagement, is required to furnish a complete report, or to give testimony, or to be in attendance in court with reference to the subject assets, properties, or business interests unless arrangements have been previously made in writing.

7. We conducted interviews with the Client and Management regarding past, present, and prospective operating results and have assumed that the information gathered in such interviews is accurate and complete.

8. Financial statements and related information provided to us in the course of this engagement by the Client or its representatives have been accepted without any verification as fully and correctly reflecting the business conditions and operating results of the relevant assets, properties, or businesses for the respective periods, except as specifically noted herein. We have not audited, reviewed, or compiled any financial information provided to us and, accordingly, we express no audit opinion or any other form of assurance regarding such information.

9. If prospective financial information provided by the Client or its representatives has been used in this analysis, we have not examined or compiled the prospective financial information and, therefore, do not express an audit opinion or any other form of assurance on the prospective financial information or the related assumptions. Events and circumstances frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material.

10. We do not provide assurance on the achievability of any forecasted results contained herein because events and circumstances frequently do not occur as expected, differences between actual and expected results may be material, and achievement of the forecasted results is dependent on actions, plans, and assumptions of management.

11. We have relied on the representations of the Client or its representatives concerning the usefulness and condition of all real and personal property, intangible assets, or investments used or held in any subject business, as well as the amounts and settlement dates of its liabilities, except as specifically stated to the contrary in this report. We have not attempted to confirm whether all assets of any subject business are free and clear of liens and encumbrances or that the entity has good and marketable title to any assets.

12. We assume that subject assets, properties, or business interests are free and clear of any or all liens or encumbrances unless otherwise stated herein.

13. We believe the information obtained from public sources or furnished to us by other sources is reliable. However, we issue no warranty or other form of assurance regarding the accuracy of such information.

14. We assume that the current level of management expertise and effectiveness would continue to be maintained, and that the character and integrity of any subject asset, property, or business interest through any sale, reorganization, exchange, or diminution of the owners' participation would not be materially or significantly changed.

15. Deloitte FAS is not an environmental consultant or auditor, and it takes no responsibility for any actual or potential environmental liabilities. Any person entitled to rely on this report wishing to know whether such liabilities exist, or the scope and their effect on the value of any subject asset, property, or business interest, is encouraged to obtain a professional environmental assessment. Deloitte FAS does not conduct or provide environmental assessments and has not performed one in the course of this engagement.

16. We have not determined independently whether any subject asset, property, or business interest is subject to (1) any present or future liability relating to environmental matters (including, but not limited to, Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)/Superfund liability) or (2) the scope of any such liabilities. The analyses, advice, recommendations, opinions, or conclusions contained herein take no such liabilities into account, except as have been reported to us by the Client or its representatives or by an environmental consultant working for the Client, and then only to the extent that the liability was reported to us in an actual or estimated dollar amount. Such matters, if any, are noted in the analyses, advice, recommendations, opinions, or conclusions contained herein. To the extent such information has been reported to us, we have relied on that information without verification and offer no warranty or representation as to its accuracy or completeness.

17. We have not made a specific compliance survey or analysis of any subject asset, property, or business interest to determine whether it is subject to, or in compliance with, the Americans with Disabilities Act of 1990, and the analyses, advice, recommendations, opinions, or conclusions contained herein do not consider the effect, if any, of noncompliance with such law.

18. We assume no responsibility for the legal description or matters including legal or title considerations. Title to the subject assets, properties, or business interests is assumed to be good and marketable unless otherwise stated herein.

19. We assume that the subject assets, properties, or business interests are responsibly owned and competently managed.

20. We assume that the Client is in full compliance with all applicable Federal, state, and local regulations and laws unless noncompliance is stated, defined, and considered in this report.

21. Unless otherwise stated, no effort has been made to determine the possible effect, if any, on any subject asset, property, or business interest due to future Federal, state, or local legislation, including any environmental or ecological matters or interpretations thereof.

22. We assume that all required licenses, certificates of occupancy, consents, or legislative or administrative authority from any Federal, state or local government, private entity, or organization have been or can be obtained or renewed for any use on which the analyses, advice, recommendations, opinions, or conclusions contained herein are based.

23. We assume no responsibility for any financial or tax reporting requirements; such reporting requirements are the responsibility of the Client for whom this analysis was prepared.

Appendix 2 — Professional Biographies of Principal Consultants

Keith Adams
Partner, Deloitte Financial Advisory Services LLP
Atlanta, Georgia

Keith is a member of Deloitte's Energy and Resources group. He consults with clients on financial analysis for decision making, enterprise financial modeling, and valuation. Keith's project execution and management experience includes: buy-side and sell-side M&A analysis, business disputes, corporate restructuring, capital budgeting, strategic alternative analysis, fresh-start accounting, purchase price allocation, asset impairment analysis, privatization, franchise disputes, tax restructuring, property tax appeals, fraudulent conveyance, financing, and others. Keith's clients have included independent power producers, regulated power and gas utilities, municipal power companies, electric distribution cooperatives, generation and transmission cooperatives, and alternative energy companies.

Paul Warley, Jr.
Managing Director, Deloitte Corporate Finance LLC
Atlanta, Georgia

Paul is a Managing Director with Deloitte Corporate Finance LLC ("DCF"). In this role, he works with clients to assist them in securing new capital for business growth, restructuring existing debt and providing consultative advice regarding debt/equity structures. His more than 24 years of experience includes structuring, approving, syndicating and documenting senior debt, subordinated debt and equity transactions; assisting clients with complicated financial structures, mergers and acquisitions; and expanding capabilities in cash flow leveraged financings and in structuring project transactions with investment grade companies. Paul also served in the U.S. Army Reserves for eight years.

Peter Hannagan
Senior Manager, Deloitte Financial Advisory Services LLP
Washington, DC

Peter is a member of Deloitte's Energy and Resources group and specializes in the power and utilities sector. He has 19 years of consulting, engineering, and project management experience, including 12 years focusing on financial analysis and valuation relating to assets and business interests in the power industry and other industries. Assets that Peter has valued and analyzed have included electricity generation assets (hydro, fossil fuel-fired, nuclear, solar, wind, and geothermal) and electricity and gas distribution assets. Peter's project execution and management experience includes: M&A analysis, financial analysis and valuation of tangible and intangible assets, asset impairment analyses, tax restructuring, sale/leaseback transactions, project financing, and property tax. Peter has performed these services for electricity and gas industry clients whose assets are located in North America, Latin America, and Europe. These studies have incorporated country and industry research for the purpose of performing financial, economic and statistical analyses.