New York
Wind Supply Curve

Prepared by:

Sustainable Energy Advantage, LLC
Robert C. Grace
Mimi Q. Zhang
Jason S. Gifford

For:

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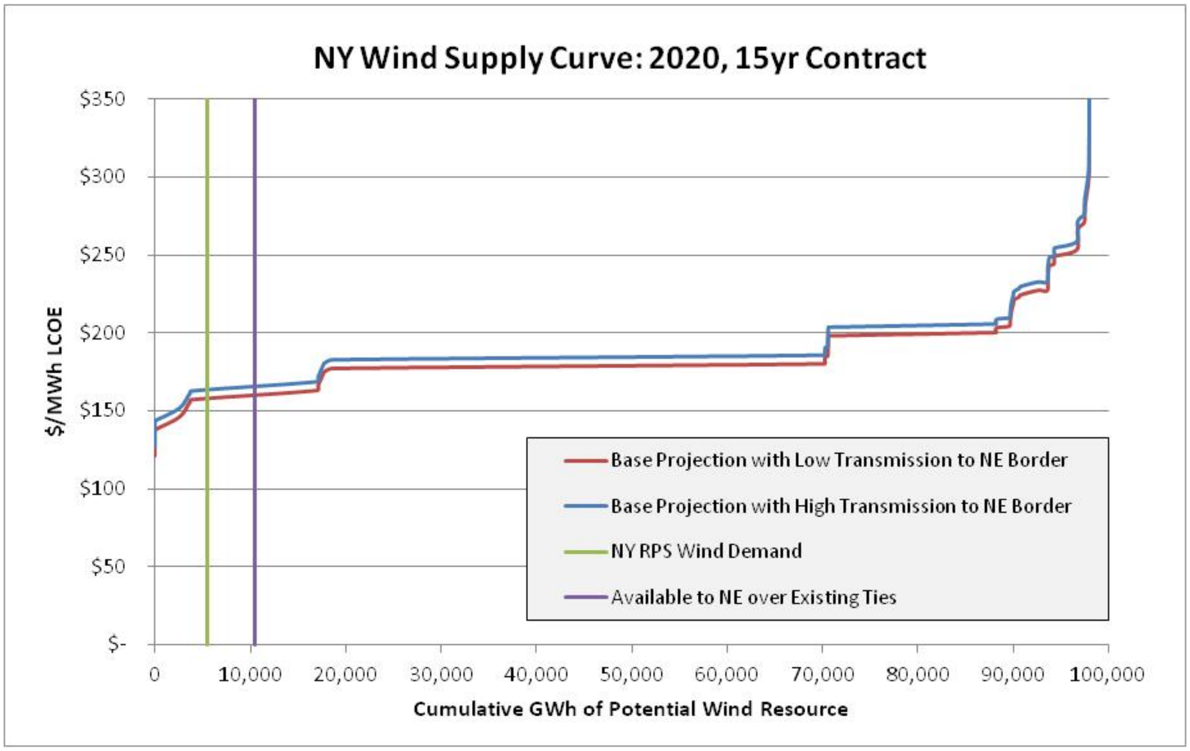
Notice

Executive Summary

The New England States Committee on Electricity (NESCOE) is seeking to develop a "baseline" of indicative costs for various representative renewable energy development scenarios in support of its exploration of coordinated competitive renewable energy procurement. To this end, NESCOE has retained Sustainable Energy Advantage, LLC (SEA) to provide an indicative 'supply curve' representing the cost and quantity of new on- shore wind resources in New York, as delivered to New England. This report describes the results and process of developing the New York wind supply curve.

The New York supply curve shows the levelized cost of energy (LCOE) and associated quantities of wind that may be available to New York assuming a 2020 start date for a 15-year contract term. These baseline LCOEs assume no Federal financial incentives, and as described in the report, are built upon a series of conservative assumptions. This conservatism suggests several reasons that wind energy could be procured at prices below those indicated in these supply curves.

The graph shown below represents the supply curve for 2020, and detailed supply curves indicating the type of wind generation (small, medium or large on-shore wind projects) are shown in the body of the report, as well as another graph which zooms in on the portion of the supply curve representing the quantities of energy that are most likely to be available and relevant to the likely renewable energy needs of New England in 2020. This portion of the supply curve comes after the quantities required within New York to meet the state's renewable portfolio standard goals by 2015, and is limited to 2000 MW representing the approximate capability of existing interties between New York and New England. Due to uncertainties in the range of costs necessary to transmit power from wind plants in New York into the New England market, the graph shows LCOEs with both a low and high estimate of additional transmission costs to the New England border.



The analysis assumes that no offshore wind developed for interconnection to serve load centers in New York would be available to serve New England, and also ignores the modest wind potential in Long Island and the New York City area which, if developable, would likely be targeted to reduce wholesale energy prices in these load pockets.

- The supply curve analysis reveals that, even accounting for uncertainty in how much of the wind resource can be permitted and developed as well as industry limits to the pace of wind development, the total quantities potentially developable are far in excess of the quantities required to meet regional renewal energy demand. In addition, while the scope of this analysis did not test sensitivity to contract duration, longer contract terms yield lower LCOEs, as demonstrated in a parallel analysis of the New England wind power supply curve.

Sensitivity analyses were conducted to explore the impact of three material underlying assumptions, each of which may cause contract actual prices to fall below the LCOEs shown in the supply curves. These assumptions include:

- **Federal Incentives**. The supply curve analysis results shown above assume that Federal tax incentives currently available to the wind industry expire. The sensitivity analysis indicates that if the current Federal Production Tax Credit (PTC) was extended under its current structure, LCOEs would decrease around $23 per MWh for 15 year contracts, with greater decreases or shorter-term contracts and smaller decreases for longer-term contracts.

- **Interest rates**. Current interest rates are at historic lows, and these lower interest rates are allowing wind projects to be developed and built at present for lower contract prices than indicated in the supply curves, even after adjusting for Federal incentives. The supply curve LCOEs shown above were calculated based in debt financing assumptions representative of longer-term expectations regarding future economic conditions. The sensitivity analysis indicates that if interest rates remain at levels consistent with current conditions, LCOEs would be roughly \$5 to \$13/MWH less than indicated in the supply curves.

- **Taller Towers, Longer Blades**. The underlying wind dataset is based on wind speed measurements at a height of 80 meters. This height is a reasonable representation of the fleet currently operating. However, looking forward, wind developers are starting to move to taller towers and longer blades capable of capturing higher wind speeds and producing higher plant capacity factors, when feasible and required to make project economics work. While not every project is able to, or will desire to, use higher towers and longer blades for a variety of reasons, projects that do so may have lower LCOEs, as the cost increases to move to taller towers and longer blades are modest compared to the increased production. For reasons described in the report, medium to large projects in the lower power ranges are most likely to pursue taller towers. A sensitivity analysis explored the impact of movement from 80 meters to 100 meters, and concluded that such a movement could result in LCOEs under 20 year contracts of \$30/MWh or more below the LCOEs indicated in the supply curve (with even greater savings for shorter term contracts). While we believe this represents the upper limit to the cost reduction potential (since many projects may use towers in the 84 – 94 meter range, and because incremental equipment costs were not fully assessed in the sensitivity), it is clear that reliance on higher towers and longer blades could have a material impact on cost and is likely to occur where logistical and permitting concerns allow.

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1 Introduction

1.1 Background

The New England States Committee on Electricity (NESCOE) is a not-for-profit organization representing the collective interests of the six New England States on regional electricity matters. NESCOE advances policies that will provide electricity at the lowest possible price over the long term, while maintaining reliable electric service and environmental quality.[1]

NESCOE conducted a Request for Information (RFI) in early 2011, the responses to which provided New England with a reasonable basis to conclude, preliminarily, that coordinating the states' efforts with respect to the competitive procurement and delivery of renewable energy resources may enable the states to achieve their various objectives in a more cost-effective manner than if each state sought to independently satisfy all of their individual clean energy objectives. In July 2011, the six New England Governors adopted a Resolution which expressed the Governors' continued interest in exploring the potential for joint or separate but coordinated competitive procurement as a means to identify those renewable resources able to serve customers at the lowest over-all delivered cost. The Governors directed continued investigation into the potential for coordinated competitive procurement.

To meet that directive from the Governors, NESCOE is seeking to develop a "baseline" of indicative costs for various representative renewable energy development scenarios. To this end, NESCOE has retained Sustainable Energy Advantage, LLC to provide an indicative cost and quantity analysis associated with developing new on- and off-shore wind resources in New England and New York. Separately, NESCOE has commissioned RLC Engineering to provide indicative, high-level cost estimates associated with representative transmission development scenarios that could facilitate the delivery of energy from new renewable generators in New England. The resulting renewable resource supply curve for New York will help signal to the states the potential ranges of "all-in" costs associated with meeting regional renewable goals and inform the next steps.

1.2 Purpose

The purpose of this report is to describe the results and process of developing the New York wind supply curve built by Sustainable Energy Advantage, LLC (SEA) for NESCOE. The supply curve models potential build-out for different types of land-based wind resources (delineated by wind speed, location, project size, and proximity to transmission) in 2020, as well as levelized cost of energy (LCOE)[2] measured at the point of interconnection into the electric system[3], plus an additional estimate of transmission costs to the New England border. For purposes of comparison to a parallel analysis performed of the New England wind power supply curve, a single supply curve was developed assuming commercial operation commencing in 2020 for a contract duration of 15 years. Due to uncertainties in the range of costs necessary to transmit power from wind plants in New York into the New England market, the graph shows LCOEs with both a low and high estimate of additional transmission costs to the New England border. These costs were developed assuming no Federal Production Tax Credit (PTC) or

[1] http://www.nescoe.com/

[2] LCOE is the fixed unit cost of energy, in $/MWh, that would allow the project to meet the investment criteria of the project's lenders and equity investors, if that amount were collected for each MWh produced over the contract term.

[3] This cost includes the cost of radial interconnection to the transmission system including stepping up to the voltage of the interconnecting line.

Investment Tax Credit (ITC) incentives. The underlying data represent wind speeds and quantities of wind land area at 80 meter hub heights.

The New York supply curve will give NESCOE an idea of:

- the total amount of developable wind in New York;
- how the total potential is broken down between the different supply blocks[4];
- the LCOE associated with the available supply, assuming that Federal incentives expire according to current law;
- the quantities of wind potentially available at different prices (or alternatively, the marginal cost of procuring various quantities of wind power);
- the sensitivity of the results to continued availability of today's Federal incentives (specifically, the Production Tax Credit);
- the sensitivity of the results to continued availability of debt at today's historically low interest rates; and
- The sensitivity of annual capacity factors and associated LCOE to the recent movement to more frequent use of towers higher than 80 meters.

1.3 Organization of this Paper

Section 2 discusses the key results of the supply curve analysis.

Section 3 summarizes the methodology used to develop the New York wind supply curves.

Section 4 provides information on key assumptions and describes the data sources used in developing the New York Wind supply curves.

Finally, Section 5 provides illustrative results under three critical sensitivities to (i) continued availability of Federal tax incentives, (ii) continuation of low interest rates, and (iii) greater use of taller towers.

[4] A supply block is a grouping of potential wind resources with similar geographic, wind profile and cost characteristics. SEA's analysis identified a total of 49 wind supply blocks within New York.

2 Results

In this study, we have developed a projection of potential supply quantities (in GWh per year) and levelized cost of energy (LCOE) for onshore wind in New York. Wind potential was considered for different wind speeds, project sizes, and distances from interconnection points, and sizes were broken down into three categories: small (up to 20 MW), medium (20-100 MW), and large (100+ MW)[5]. Each grouping of technology and size was further segregated by 'wind power factor' (a representation of power in the wind at that location), and by distance from the transmission system. Each of these small groupings is a "supply block" and is represented in the following charts as a single data point.

2.1 Conclusions & Observations

The supply curve analysis reveals some important high level conclusions including:

- There is a large amount of potential supply, especially in the large wind blocks. Even accounting for uncertainty in how much of the resource potential can ultimately be permitted, the total developable wind resources greatly exceed the quantities required to meet likely regional needs for incremental renewable energy.
- Due to scale economies, large wind blocks typically have the lowest LCOEs, but medium blocks for comparable wind speeds are not far behind.
- New York's windiest locations are largely off limits to development, falling within protected areas such as the Adirondack and Catskill areas. Of the remaining land area, large quantities of land possess fairly similar characteristics, resulting in a less steeply-sloped supply curve than those developed for New England. In fact, the portion of the curve expected to be available to New England by 2020, after New York first satisfies its own RPS needs, is fairly flat, suggesting less uncertainty as to the cost of wind available to New England as a function of how much of the wind development potential could actually be permitted. New England has a steeper supply curve.

2.2 Supply Curve for 2020, 15 Year Contracts

The nominal LCOE of all supply blocks was modeled using National Renewable Energy Laboratory's (NREL) Cost of Renewable Energy Spreadsheet Tool (CREST) model. The results assume that Federal incentives currently available to wind projects- Production Tax Credit (PTC), Investment Tax Credit and Cash Grant in lieu of Investment Tax Credit, have all expired at the end of 2012, their current sunset date. Section 5.2 considers the reductions in LCOE that would result from a long-term extension of the PTC.

The supply curve for 2020, showing the LCOE that would be expected for 15-year contracts, is shown in Figure 1 for the full supply curve and Figure 2 for the first 12,000 GWh/yr.

[5] Community-scale and distributed generation projects were ignored for the purposes of this study, as the underlying wind data set was not developed at a sufficient level of granularity. These resources, if modeled, would add hundreds of MW to the supply curve. Many of these projects are being driven by state incentive programs and/or net metering regulations, and therefore are unlikely to be contributors to the type of coordinated procurement activities being considered by the New England states.

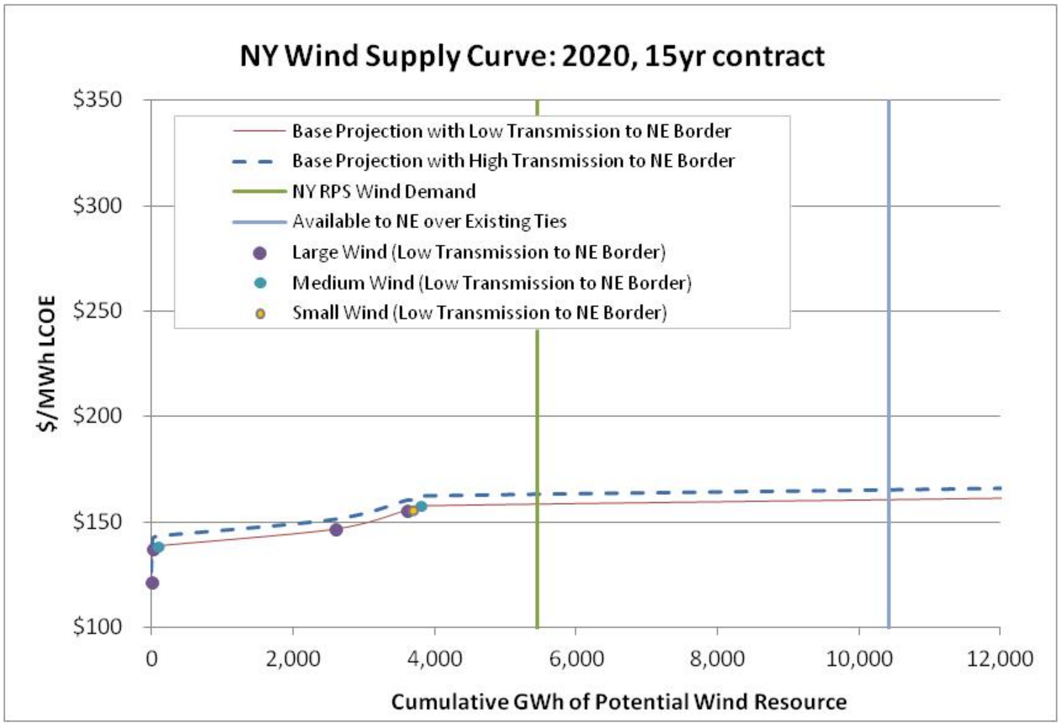

Figure 1

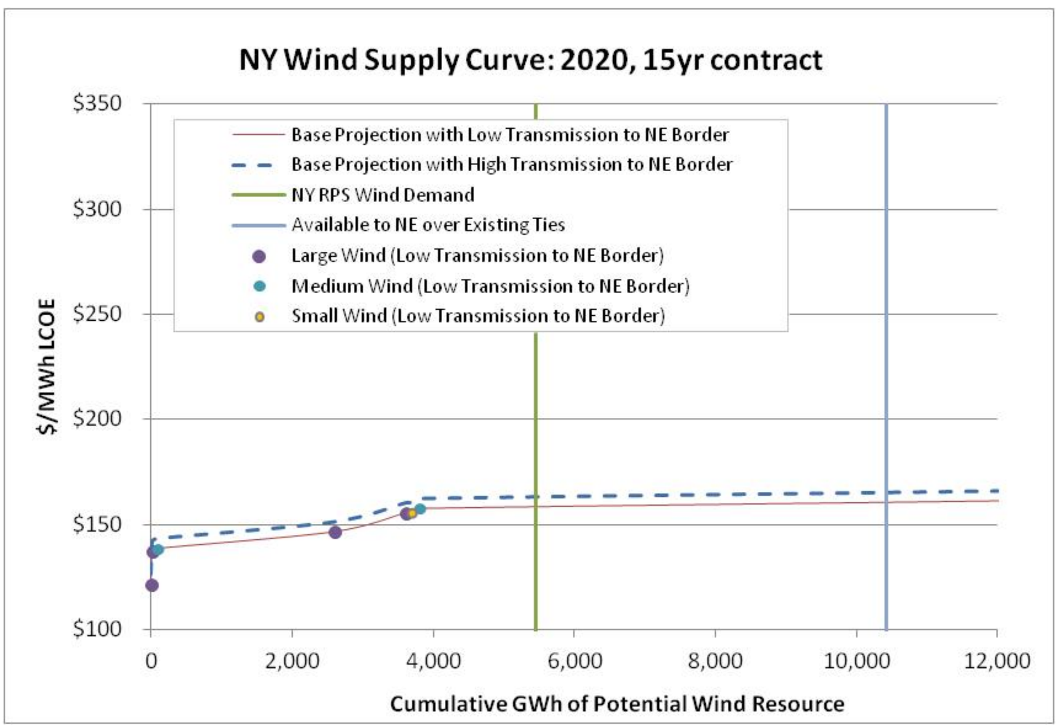

Figure 2

These graphs show that LCOE ranges from $120-$170/MWh for the first 12,000 GWh of potential new supply in 2020 under a 15 yr contract term and includes a mixture of all technology types. The quantities assumed available to New England, after New York has satisfied its own RPS needs, falls into the $163 to $169/MWh range.

3 Methodology

The NESCOE supply curve was constructed in a manner similar to that used by SEA in a number of other studies: SEA's New England Renewable Energy Market Outlook (REMO) market fundamentals analysis, the Maine Governor's Task Force, and a New York RPS cost study performed for the New York State Energy Research and Development Authority. The core methodology focuses on dividing New York's wind potential into a number of supply blocks, each defined by different combinations of geographic location, wind power density and resultant capacity factor, project scale (based on contiguous wind land area) and proximity to transmission. Each supply block is then associated with a 'cost profile'. In turn, a cost profile is characterized by a notional wind project size, and typical capital and operating costs (which in turn depend on location, size and distance to transmission). For each supply block, a levelized cost of energy was calculated assuming a 2020 start year and 15 year contract term based on the associated cost profile and the supply block's capacity factor. SEA utilized public available data where possible for maximum transparency, including using the publicly-available CREST model. The CREST model described further in Section 3.5, was developed by SEA for NREL to calculate levelized cost of energy under various assumptions.

3.1 Supply "Blocks"

Supply blocks were developed by allocating the total potential regional into 49 blocks with common characteristics:

-Geographic location (zone)
-Typical Project Size
-Wind Quality
-Distance from Transmission
-Expected Capacity Factor

All blocks were initially delineated by zone, then by distance from transmission. Blocks were also characterized by wind power density[6] and project size. Where the underlying wind potential analysis showed very small quantities of wind land area with a particular power density, these areas were condensed into composite blocks that combine smaller supply blocks with different power densities. Thus, the composite blocks use averaged power densities.

Blocks are defined at a 'typical' project size for purposes of spreading fixed costs (e.g. interconnection) over an associated volume of energy production. The supply curve does not require that the amount shown in a given year for a given block equal or exceed the typical project size. This approach is consistent with the fact that actual projects often span different wind speed classes.

3.2 Quantity (Nameplate MW)

The total quantity potential (in nameplate MW) for each supply block was estimated by taking into account total land area in each block, and then making three sets of adjustments. First, certain land use categories were completely excluded from consideration as incompatible with wind development. Such land use categories included airports, cities, national parks, etc. A set of secondary exclusions were applied to the remaining windy

[6] Wind Power Density, in units of Watts/m^2, is a measure of the power in the wind. It is a function of both wind speed and air density. Air density is in turn a function of elevation, temperature and humidity. The higher the air density, the higher the power output predicted from a wind turbine for a given wind speed. Since air density differs at different elevations, the use of power density is a somewhat more accurate determinant of wind project output than is the wind speed alone. The area in the expression represents the swept area of the blades.

land area to land use categories for which development is expected to be challenging. These categories were not always fully excluded, but were given a derate based on difficulty for use as wind development sites. This step addresses the reality that wind projects cannot be sited on all available land. The remaining land quantity was then converted to MW potential using a development density assumption, which is a MW/km^2 conversion from the raw wind analysis procured from AWS Truepower (AWST). Finally, an "ability to permit" derating factor was applied to reflect the expected influence of various siting and permitting challenges, further reducing the available supply.

The total potential MW for each block represents the final total wind power that each block area can support. In order to assure that there was no double counting of wind generation potential, SEA identified all wind generation that is either currently operating or under construction, assigned it to a corresponding block, and subtracted that 'committed capacity' from the projected resource potential.

3.3 Performance

For each wind power class in each state, an associated annual average capacity factor was developed to represent the mean expected annual production. Each block was assigned a corresponding capacity factor that was used to estimate its annual energy production (in GWh/yr).

3.4 Cost Inputs

Cost assumptions were used as inputs in the CREST model to calculate the LCOE for each typical project in each supply block. There were three cost components:

- Installed Capital Cost, excluding the cost of interconnection, on a $/kW basis. This category includes all categories of hard and soft costs typically financed upon a project's date of initial commercial operation, including construction interest, financing fees, engineering and permitting costs, etc.

- Operations and Maintenance (O&M): inputs for both variable and fixed O&M costs were developed for each supply block. This category includes all cost categories not included in Installed Capital Costs, including property taxes, site lease/royalty payments, and insurance.

- Direct Interconnection Costs: these costs were estimated as a function of (a) distance from the point of interconnection to the transmission system and (b) project size, and each project was assumed to require both substation and line costs. Assumptions vary depending on the size of the project, different voltage requirements and substation costs.

3.5 Cost of Renewable Energy Spreadsheet Tool (CREST)

The Cost of Renewable Energy Spreadsheet Tool (CREST) was developed by SEA for NREL. CREST has three technology-specific versions, including one for wind energy.[7] Inputs to the CREST model include capital and operating costs, system performance, and incentive and financing parameters. Model outputs include the cost of energy on a levelized basis.

CREST was developed as a publicly available and transparent tool to aid policymakers in estimating renewable energy cost of energy for various public policy purposes, such as establishing performance based incentives including feed-in-tariffs. The model is designed to calculate the cost of energy, or minimum revenue per unit of

[7] The model and supporting documentation are available at the NREL web site. http://financere.nrel.gov/finance/content/CREST-model

production needed, required for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return. As the model was developed in Microsoft Excel, it offers the user a high level of transparency including full comprehension of the underlying equations and model logic.

The CREST model allows the user to specify varying levels of capital and operating cost detail. With respect to capital costs, CREST allows the user a range of input options from a simple $/kW value to a highly detailed cost component list. For this analysis, the "intermediate" approach was selected allowing for separate modeling of installed cost components for generation equipment and interconnection. The CREST model also allows the user to easily conduct sensitivity analyses, including variations in incentive payment durations, and the ability of equity investors to efficiently utilize tax incentives.

3.6 Levelized Cost of Energy

For each combination of in-service year and contract term, the LCOE for each supply block was calculated using the CREST model, which models the LCOE as the expected unit price under a long-term contract. In addition to cost and performance inputs described above, the calculation of LCOE on a nominal dollar basis required assumptions for:

- Capital structure (percentage of debt versus equity, while assuming a single mortgage-type loan for debt financing)
- Cost of capital (cost of debt, threshold after-tax return required by equity investors)
- Incentives assumptions (the base LCOEs were calculated without any Federal or state incentives)
- Depreciation
- Decommissioning
- Lender Debt Service Coverage requirements
- Post-contract revenue assumptions.

CREST modeling of LCOE is a simplified representation of project cash flows. While CREST does not reflect the level of detail used by developers for project finance purposes, it has been thoroughly vetted in development for NREL, and is considered to provide a good approximation of LCOE for policy analysis purposes. Furthermore, CREST is capable of modeling inputs at a simple, intermediate or complex level of detail. For purposes of this study, we have used a combination of simple and intermediate inputs, reflective of a representative financing structure and use of cost input assumptions based on aggregated project cost data, rather than detailed component-level cost estimates.

3.7 Transmission to the New England Border

In order to project the cost of New York wind as delivered to New England load, we developed an estimate of the cost of transmitting wind energy from the wind project's node to ISO New England. This projection considered locational-based marginal energy price (LMP) differences between representative wind generation zones or nodes, and the New England LMP at the border.

There are significant uncertainties with respect to the costs of transmission usage and congestion attributable to such transactions, and the estimates provided herein must be considered as indicative. For example:

- The LMP differences depend on relative shifts in market prices among locations, which in turn can be impacted by many factors which could change between now and 2020, including generation additions or subtractions, shifts in fuel prices, and new transmission projects.
- Particularly for intermittent generation like wind power, there is an inherent lack of precision in scheduling generation across the border between NYISO and ISO-NE markets. Additional costs and difficult-to-quantify risks may derive from over-scheduling deliveries relative to actual wind production (resulting in sales to New England that may not be economic) as well as under-scheduling (resulting in RECs that get stranded in New York and which may have limited revenue opportunities in-state).
- By 2020, efforts to reduce or eliminate seams between NYISO and ISO-NE could result in changes in how transmission congestion or usage costs are applied to such transactions.

To attempt to bound the range of potential costs in this category, a low estimate was developed based on actual historical LMP differences, and a high estimate was developed which added $5/MWh to the low estimate, consistent with a mid-range figure from proprietary analysis of this issue performed by SEA in the past.

4 Detailed Assumptions / Data Sources

4.1 Supply Blocks

The specific number, type and characterization of supply blocks depend on the factors described below. Block names include shorthand notation for wind power class and distance from transmission.

On-shore Wind

Characteristics of on-shore supply blocks included:

- **Zone (1 or 2)** [8]
- **Size:** one of three classes of project size:
    - Small: < 20MW
    - Medium: 20-100MW, or
    - Large: > 100MW.
- **Distance from Transmission:** distance from each group of wind resource to the closest transmission line of 69 kV or higher, classified as one of four distances:
    - T1: 0-5 Miles
    - T2: 5-10 Miles
    - T3: 10-20 Miles
    - T4: 20+Miles.
- **Wind Speed:** by power class (which takes into account air density) at 80 meters:
    - Power Range 3: 300-400 W/m^2
    - Power Range 4: 400-500 W/m^2
    - Power Range 5: 500-600 W/m^2
    - Power Range 6: > 600 W/m^2

[8] For purposes of this analysis, the wind resource data in the dataset acquired by SEA for earlier studies aggregated the NYISO load zones into three 'mega-zones'. Zone 1 represents the upstate NYISO load zones A through E; Zone 2 represents NYISO load zones F, G, H and I, and Zone 3 represents downstate NYISO load zones J and K. These zones were aggregated based on similar locational energy prices. For purposes of this analysis, wind potential in Zone 3 were ignored as both small and unlikely to be sold into New England (due to high local need for generation in these high-cost load pockets).

4.1.1 Raw Windy Land Area

The data sets representing windy land area which identifies the square kilometers (km^2) in each category identified above. The underlying data comes from an analysis developed for SEA by AWS TruePower (AWST) in late 2007, for use in an RPS Cost Study performed for the New York State Energy Research & development Authority (NYSERDA).[9] The data was based on 80 meter wind data characterized on a 200 m resolution Geographic Information System (GIS) grid. A standard minimum distance of 500 m was applied to abutters to account for setbacks, and the remaining land was grouped into 'developable' regions of at least 1 km^2 in size.

4.1.2 Progressive Reduction in Developable Wind Capacity (Exclusions)

A series of exclusions were applied to the onshore raw wind data. First, a 100% exclusion layer was applied to remove much of the wind land area from further consideration. It was assumed that no wind would be built in regions matching the criteria identified as "100% Exclusionary Lands" in Appendix A.

Secondary Exclusions

The land area remaining after the first exclusion was then subject to secondary exclusions. AWST and SEA developed additional derating factors to further reduce the windy land area in various 'secondary exclusion' land use categories. This additional reduction reflects the reduced likelihood of development in the areas meeting the applicable descriptions. The secondary exclusion classifications and assumptions are described as "50% Exclusionary Lands" in Appendix A.

As discussed further in Section 4.1.4, further derating was applied to account for more realistic limits to the development potential.

4.1.3 Development Density

For the purposes of this study, SEA commissioned an updated analysis from AWST in August 2011 to assess the development density (in MW per km^2) to be applied to the remaining windy land. SEA applied 7.5 MW/km^2, a figure in the middle of the range provided by AWST.

4.1.4 Permitability

To reduce the developable windy land area to reflect expected limits on permitting, SEA further reduced all remaining land area to 65% of the total potential reflecting SEA's subjective assumption on the proportion that would be developable.

4.1.5 Phase-in

SEA includes its own subjective estimates for the maximum buildout rate for regional wind generation, based on both development timelines for potential projects, and expected limits to the wind industry's infrastructure installation capabilities. The purpose of these assumptions is to constrain the model from projecting unrealistically high proportions of resource potential buildout before the industry would be physically capable of accomplishing the buildout. In short, it keeps the model from indicating the feasibility of building all potential resources in the first year, or even first several years, as such an outcome would be highly unrealistic. Since this analysis only looks at 2020, most of the NY land-based wind potential could be built by that timeframe, so this adjustment has a negligible impact on the overall supply curve.

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[9] La Capra Associates & Sustainable Energy Advantage, LLC (2008), New York Renewable Portfolio Standard Cost Study Update - Main Tier Target and Resources, prepared for New York State Energy Research and Development Authority.

4.1.6 Subtracted Committed Supply

Contracted committed supply, calculated as MW already operating or under construction, was removed from the total potential for each block to calculate incremental developable potential. Around 1,250 MWs of capacity were removed in this manner.

4.2 Performance

To project energy production associated with each supply block, SEA commissioned an updated analysis from AWST in August 2011 to analyze the average annual capacity factors associated with each supply block by state, at 80 meters hub height. The updated data reflect the latest understanding of the performance of current and near-term wind generation technology, and also corrects for historical industry forecast bias experienced prior to 2008/2009. The AWST analysis provided an expected capacity value for each wind power class on a "P50" basis, representing the quantity of energy production with a 50% probability of being exceeded. The actual capacity factor may vary by year, but using the P50 value is a conventional planning assumption.

As noted, the data set available to SEA for purposes of this analysis is at 80 m wind speeds. We note here that the onshore wind capacity factors, and associated costs, are potentially quite conservative. Current development practices are moving to higher towers and longer blades where possible to capture higher wind speeds available. The difference can result in as much as approximately 8% higher annual energy production for a 100 meter tower (the highest being planned for the region). Use of higher towers would materially impact the capacity factor, and significantly reduce the calculated LCOEs for each block. We explore this sensitivity later in this report.

Capacity factor degradation over time: Wind capacity factors from AWST, which represented year 1 capacity factors, were levelized over a 20 year period assuming a 0.25% annual production degradation. This resulted in a levelized capacity factor that was approximately 1% lower than the initial value. For example, a block with an initial value of 30% would become around 29%.

4.3 Cost

4.3.1 Capital Cost

Installed capital costs, on a nominal $/kW basis excluding interconnection costs, were derived by SEA based on review of a wide range of publicly available data sources as well as extensive interviewing of market participants active in the Northeast. Sources considered included NREL compilations of other study results[10], the Lawrence Berkeley Laboratory/Department of Energy's 2010 Wind Technologies Market Report[11], EIA's 2011 Annual Energy Outlook,[12] a 2009 Cost of Generation Study, components of which were developed by KEMA[13] and the California Energy Commission[14] (the '2009 KEMA/CEC Cost of Generation Report'), NREL studies, and additional research and interviews.

To project capital costs by year, technology learning curve indices were taken from the 2009 KEMA/CEC Cost of Generation Report and combined with the AEO2011 GDP Index to account for inflation.

[10] http://www.nrel.gov/analysis/docs/re_costs_20100618.xls
[11] http://www1.eere.energy.gov/wind/pdfs/51783.pdf
[12] http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf
[13] KEMA, Inc., RENEWABLE ENERGY COST OF GENERATION UPDATE, prepared for California Energy Commission Public Interest Energy Research Program (Aug, 2009).
[14] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

4.3.2 O&M Cost

O&M Cost estimates were adapted from the KEMA/CEC Cost of Generation Report. For small projects, a 5% adder was applied to fixed O&M costs. Variable O&M costs were held constant across all wind blocks.

4.3.3 Interconnection Costs

Current interconnection costs were estimated as a function of distance from the transmission grid based on a simple model developed by SEA. Each project was assumed to require both substation and line costs. Depending on the size of the project, different voltage requirements and substation costs were assigned based on consultation with an electrical engineering firm involved in numerous interconnection studies for wind projects in the northeast.

Interconnection costs were escalated by year using a hybrid index that combined the AEO2011 indices for commodities, metals and metal products, and the consumer price index. Different substation and line costs were assumed for each size category to match different voltage assumptions by category. The distance from transmission used to estimate line costs was the midpoint in the range for each transmission category (e.g. 0-5 miles used 2.5 miles).

4.4 LCOE

4.4.1 Financing Assumptions

The following assumptions were made for project financing for the reference case (results presented in Section 2) and for a low-interest sensitivity case discussed later in Section 5.2.

	Debt Term	Capital Structure: % Debt	
Contract Term (yrs)	yrs	Reference interest rates	Low interest rates
15	14	62%	62%

Technology Type	Cost of Equity	Cost of Debt	
	%	Reference	Low Interest
Wind (<20 MW)	13.0%	8.5%	7.0%
Wind (20-100 MW)	12.0%	8.0%	6.0%
Wind (>100 MW)	11.0%	7.0%	5.5%

4.4.2 Incentives

The reference case assumed no state or Federal incentives, but a sensitivity case described in Section 5.1 models the impact of the extended availability of a 10-year PTC, with a current value of 2.3 ¢/kWh.

4.4.3 Financing Constraints

Lenders require minimum cash flow to assure their payment by establishing minimum debt service coverage (DSC) ratios. Assumptions for the percentage of debt were developed to meet a minimum DSC Ratio of 1.25 and an average DSC ratio of 1.45.

4.4.4 Terminal Revenue

Wind projects were assumed for CREST modeling to have a 20 year economic life. In the case of contracts for 15 years, assumptions were required for post-contract revenue.

Sources for recent and publically available forecasts for post-contract revenue for New York were limited. Terminal revenue beyond the contract end date used NY ISO's Congestion Assessment and Resource Integration Study (CARIS) [15] for energy value by zone, and the 2009 New York State Energy Plan for capacity price. Where energy and capacity forecasts did not extend through the timeframe needed for the CREST model, the forecasts were extended using the growth rate from AEO 2011's generation price forecast for upstate New York. In addition to energy and capacity, we assumed $5/MWh for each renewable energy credit (REC). This is typically more value than traditionally conservative lenders would attribute to these post-contract values, and therefore may slightly understate the LCOEs (note: most other assumptions would tend to overstate LCOEs, as discussed in Section 5.)

4.5 Transmission to the New England Border

Transmission costs to the New England border were added based on an analysis of the most recent 12 months of LMP history at various New York zones and nodes corresponding with high wind power potential, as well as the ISO- NE border LMP over the same period. As described earlier, these figures were increased in a high case to address a variety of factors, as follows:

Low transmission adder:

- Zone 1 wind generation: $10/MWh
- Zone 2 wind generation: $2/MWh

High transmission adder:

- Zone 1 wind generation: $15/MWh
- Zone 2 wind generation: $7/MWh

5 Sensitivity Cases

In this section, we provide sample results to illustrate the sensitivity of results shown in Section 2 to key assumptions. The first sensitivity case shows the potential impact of continuation of Federal incentives currently slated to expire by the end of 2012. The last two sensitivity cases discuss factors that we believe should be considered by NESCOE and its managers in interpreting the results. As described in each section, each factor suggests that the results shown in Section 2 may be quite conservative, meaning that there is a good probability that competitive procurement under long-term contracts could yield prices *lower* than those indicated by the results in Section 2.

5.1 Continuation of Production Tax Credit

In order to quantify the LCOE impact of a Federal production tax credit (PTC), the LCOE with PTC was calculated for a number of sample blocks and compared to the LCOE without PTC. For purposes of this sensitivity, we assumed that the current Federal PTC was extended under its current structure (we ignored the short-term

[15] New York ISO, *2011 CARIS 1 Base Case Result* (October 24, 2011) http://www.nyiso.com/public/webdocs/committees/bic_espwg/meeting_materials/2011-10-24/Modeling_Results_10-15-11_for_posting_v2.pdf

stimulus ITC and cash grant programs). Table 1 shows the **LCOE decreases** that could be expected for a sampling of blocks.

Table 1. Impact of Production Tax Credit

Wind Small Zone1 P3T1	23.00
Wind Small Zone1 P4T1	22.00
Wind Medium Zone1 P3T1	23.00
Wind Large Zone1 P6T1	23.00

5.2 Low Interest Rates

Even after adjusting for the availability of Federal incentives for projects that are being built in the current timeframe, contract prices well below those projected herein are feasible. One of the reasons is that today's interest rates are at historic lows. The reference case presented in Section 2 was based on debt financing assumptions representative of longer-term expectations, as it is unrealistic to assume that today's interest rates would continue indefinitely. However, it is certainly possible that a lower real interest rate environment may continue into the future.

To help illustrate the potential impact of these assumptions, a sensitivity analysis was performed using lower interest rates for cost of debt, which yields lower LCOE results. Interest rates for this case were 1.5-2% lower than for the reference case and varied by technology type, as shown in Table 2. The reference case used long-term estimates of cost of capital for purposes of estimating projects built in 2020. Due to the uncertain future of this low-cost capital environment, the reference and sensitivity case results can be treated as high and low bounds, with expectations likely somewhere in between.

Table 2. Cost of Debt Assumptions

Technology Type	Cost of Debt	
	Reference	Low Interest
Wind (<20 MW)	8.5%	7.0%
Wind (20-100 MW)	8.0%	6.0%
Wind (>100 MW)	7.0%	5.5%

The LCOE results shown in Table 3 for the lower interest rate case show the **LCOE reductions** that would result under the lower interest rates. The results were between $5-13/MWh lower than for the reference case.

Table 3. Impact of Low Interest Assumptions

Wind Small Zone2 P3T1	8.00
Wind Small Zone1 P3T3	10.00
Wind Small Zone2 P5T1	6.00
Wind Small Zone2 P6T2	7.00
Wind Medium Zone2 P4T1	8.00
Wind Medium Zone1 P6T1	8.00
Wind Large Zone1 P4T1	6.00
Wind Large Zone1 P6T1	5.00

5.3 Taller Towers, Longer Blades

Our data set for onshore wind resource potential is based on 80 meter data, corresponding to 80 m hub heights. This height is a reasonable representation of the fleet currently operating. We polled the leading wind developers in the region to assess the mix of hub heights being used in projects currently under development, and concluded that looking forward, the industry seems to be moving (for larger regional projects) to a mix of 84, 90, 94 and 100 m towers. Higher hub heights are often associated with longer blades. The combination substantially improves expected energy output (capacity factor) at small incremental cost. Many projects will not use higher towers and longer blades for a variety of reasons, including site suitability, access, transportation or construction logistics, and permitting (greater visual and sound impacts, leading to the need for greater buffer zones).

At our request, AWST estimated that a move from 80 to 100 m and associated longer blades may impact a site materially in terms of improved output, with only small increases in capital costs. An example: this move could make a 16% capacity factor site into a 24% capacity factor site, or a 24% capacity factor site into a 32% capacity factor site. Analytically, it is not possible to project a mix of hub heights, because a developer could select from a range on a particular site, and the choices are driven by a range of factors and constraints, only one of which is economics. This impact is more likely to affect medium to large projects in the lower power ranges (e.g. power range 3 and 4), since (i) small projects closer to residential areas are unlikely to allow higher hub heights, (ii) projects that are already in high power classes tend to be on ridgelines or areas that may be difficult to permit or deliver taller turbines, and (iii) the marginal economics of lower wind sites yield a higher relative value for the additional production, thus providing greater incentive to pursue higher hub heights despite the additional challenges described above.

To estimate the potential impact of moving *all* towers in a given project to a 100 m hub height, we adjusted the capacity factors by AWST's 8% additional annual production.[16] Due to the mix of tower heights expected, the values shown in Table 4 represent the upper limit to the **LCOE decreases** that could be expected, from moving to 100 m towers. A 90 m tower would likely product reductions in the LCOE that are less than 50% of the reductions from moving to 100 m towers, due to the non-linear relationship of wind speed and capacity factor. Nonetheless, the results show the *potential* for LCOEs to be around $30 to $50 per MWh lower than indicated in Section 2, if developers move to the tallest turbines and longest blades available. Table 4 includes the results for a few example blocks. Note that these figures may be somewhat overstated, as a detailed analysis of cost differences (expected to be modest on a $/kW basis) was not conducted.

Table 4. Impact of Higher Hub Height Assumptions

Wind Small Zone2 P3T1	54.00
Wind Small Zone2 P5T3	42.00
Wind Medium Zone1 P4T1	47.00
Wind Large Zone2 P5T1	28.00

[16] This is an approximation. It is important to note that not all blocks would experience an 8% capacity factor increase if a new capacity factor study was done at 100m, but the 8% value was used as a benchmark to gauge the impact of a significant capacity factor increase. A more costly AWST study at different hub heights would be required for a more accurate estimate of the capacity factor increases that would be expected for various supply blocks.

Appendix A – Land-Based Wind Classifications and Exclusions

New York Site Screening Criteria

		Data Source	Date	Applied Buffer
Wind Resource Data				
	New York State Power Density @ 80m	AWS Truewind & NYSERDA (wind data resolution 200m)	2003	N/A
	New York State Mean Wind Speed @ 80m	AWS Truewind & NYSERDA (wind data resolution 200m)	2003	N/A
100% Exclusionary Lands				
(Land Areas that were completely excluded from this analysis)				
	Protected Lands			
	National Historic Preserves	NYS Department of Environmental Conservation	2007	N/A
	Natural Resource Land	NYS Department of Environmental Conservation	2007	N/A
	Wildlife Management Areas	NYS Department of Environmental Conservation	2007	N/A
	Adirondack & Catskill Park Forest Preserve	NYS Department of Environmental Conservation	2007	N/A
	Unique Wildlife Preserves	The Nature Conservancy / NYS DEC	2007	N/A
	State and Local Parks	ESRI Parks	2007	N/A
	National Historic Parks	ESRI Parks	2007	N/A
	National Recreation Areas	ESRI Parks	2007	N/A
	National Monuments	ESRI Parks	2007	N/A
	National Wildlife Refuges	ESRI Parks	2007	N/A
	National Park Service Land	USGS National Atlas	2007	N/A
	Fish and Wildlife Serivice Lands	USGS National Atlas	2007	N/A
	Indian Lands	USGS National Atlas	2007	N/A
	Status 1 Lands (Protected Lands)	GAP Analysis	2007	N/A
	State Parks, Recreation & Historic Lands	NY State Ofice of Parks, Recreation & Historic Lands	2006	N/A
	Land Use/Land Cover			
	Urban Areas	USGS National Land Cover Data: Medium and High Intensity Developed Lands (NLCD Classes 23&24)	2001	Class (23) 0.5 Miles Class (24) 1 Mile
	Wetlands & Waterbodies	USGS National Land Cover Data: Open Water (NLCD Class 11 & 90-95)	2001	N/A
	Large Airports	ESRI Airports	2007	20,000 Feet
	Medium Airports	ESRI Airports	2007	10,000 Feet
	Small Airports	ESRI Airports	2007	N/A
	Existing Wind Farms	AWS Truewind Wind Farm Data - Maple Ridge, Weathersfield, Madison, Fenner, Steel Winds	2007	N/A
	Slopes > 20%	Derived From National Elevation Data DEM 30m	2001	N/A
50% Exclusionary Lands				
(Lands where only 50% of the wind resource area was included in the analysis)				
	Protected Lands			
	Deparment of Defense Lands	USGS National Atlas	2007	N/A
	Forest Service Lands	USGS National Atlas	2007	N/A
	State Forest Lands	NYS Department of Environmental Conservation	2007	N/A
	Lands Within the Adirondack and Catskill Parks outside the 100% exclusion status (Forest Preserve)	ESRI Parks & GIS analysis	2007	N/A
	Land Use/Land Cover			
	Non Ridgecrest Forest Analysis	Intersection of Slopes $\leq$ 8 Degrees (NED) and USGS National Land Cover Data: Deciduous Forest, Evergreen Forest, & Mixed Forest (Classes 41-43)	2001	N/A