2015 Cost of Wind Energy Review

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National Renewable Energy Laboratory

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Technical Report
NREL/TP-6A20-66861
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March 2017
Contract No. DE-AC36-08GO28308

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Prepared under Task No. WE15.CA02

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303-275-3000 • www.nrel.gov

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List of Acronyms

AEP_{net}	net annual energy production
AEP	annual energy production
ATB	Annual Technology Baseline
AWEA	American Wind Energy Association
BNEF	Bloomberg New Energy Finance
BOEM	Bureau of Ocean Energy Management
BOS	balance of system
bp	basis point
CapEx	capital expenditures
COE	cost of energy
C_p	coefficient of power
CPI	Consumer Price Index
CRF	capital recovery factor
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EWEA	European Wind Energy Association
FCR	fixed charge rate
IEA	International Energy Agency
ITC	investment tax credit
GW	gigawatt
LBNL	Lawrence Berkeley National Laboratory
kW	kilowatt
LCOE	levelized cost of energy
m	meter
m/s	meters per second
MACRS	Modified Accelerated Cost Recovery System
MAIN	maintenance
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OEM	original equipment manufacturer
OPER	operation
OpEx	operational expenditures
OWDB	Offshore Wind Database
PPA	power purchase agreement
PTC	production tax credit
PVdep	present value of depreciation
ReEDS	Regional Energy Deployment System
SCBS	system cost breakdown structure
TWh	terawatt-hour
WACC	weighted-average cost of capital
WISDEM™	Wind-Plant Integrated System Design and Engineering Model

Executive Summary

This report uses representative utility-scale projects to estimate the levelized cost of energy (LCOE) for land-based and offshore wind plants in the United States. Data and results detailed here are derived from 2015 commissioned plants. More specifically, analysis detailed here relies on recent market data and state-of-the-art modeling capabilities to maintain an up-to-date understanding of wind energy cost trends and drivers. It is intended to provide insight into current component-level costs as well as a basis for understanding variability in LCOE across the industry. This publication reflects the fifth installment of this annual report.

The primary elements of this 2015 report include:

- Estimated LCOE for a representative, land-based wind project installed in a moderate wind resource located within the interior (hereafter referred to as "Interior") region of the United States in 2015
- Estimated LCOE for representative offshore, fixed-bottom, and floating projects, using National Renewable Energy Laboratory (NREL) models and a database informed by projects installed in Europe for a representative site on the U.S. North Atlantic Coast in 2015
- Sensitivity analyses showing the range of effects that basic LCOE variables could have on the cost of wind energy for land-based and offshore wind power plants and NREL's historical, calculated LCOE estimates for land-based and offshore wind plants
- Estimated range of LCOE for land-based wind projects across the contiguous United States that were divided into five regions and based on geographically specific wind resource conditions paired with approximate wind turbine size characteristics
- An update on prior analysis (Bolinger and Wiser 2011) of the drivers of wind turbine prices in the United States to estimate and understand the relative contributions of various endogenous and exogenous drivers to the decline in wind turbine prices observed since 2010.

Key Inputs and Results

Throughout this report, the representative land-based and offshore project types are referred to as "reference projects." Tables ES1, ES2, and ES3 summarize the basic LCOE inputs for the reference land-based, fixed-bottom, and floating offshore wind projects, with some additional detail about project capital expenditures (CapEx) and the respective turbine capacity factor associated with the net annual energy production estimate. These are the assumptions used to calculate the LCOE for the 2015 reference projects using an installed average nameplate megawatt (MW) capacity. Unless specifically stated, all data and analysis used in the report are in 2015-nominal dollars, taking into account changes caused by inflation, relative to previous reports.

Table ES1. Summary of the Land-Based Reference Project Using 2.0-MW Turbines

	2.0-MW Land-Based Turbine ($/kilowatt [kW])	2.0-MW Land-Based Turbine ($/megawatt-hour [MWh])
Turbine capital cost	1,209	33.2
Balance of system	330	9.1
Financial costs	151	4.1
Capital expenditures (CapEx)	**1,690**	**46.4**
Operational expenditures (OpEx; $/kW/yr)	51	14.6
Fixed charge rate (%)	9.6	
Net annual energy production (MWh/MW/yr)	3,494	
Net capacity factor (%)	39.9	
TOTAL LCOE ($/MWh)	**61**	

Table ES2. Summary of the Fixed-Bottom Offshore Reference Project Using 4.14-MW Turbines

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
Turbine capital cost	1,466	41.8
Balance of system	2,167	61.9
Financial costs	983	28.0
Capital expenditures (CapEx)	**4,615**	**131.7**
Operational expenditures (OpEx; $/kW/yr)	179	49.6
Fixed charge rate (%)	10.3	
Net annual energy production (MWh/MW/yr)	3,608	
Net capacity factor (%)	41.2	
TOTAL LCOE ($/MWh)	**181**	

Table ES3. Summary of the Floating Offshore Reference Project Using 4.14-MW Turbines

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
Turbine capital cost	1,466	42.0
Balance of system	4,146	118.8
Financial costs	1,035	29.6
Capital expenditures (CapEx)	**6,647**	**190.4**
Operational expenditures (OpEx; $/kW/yr)	138	38.4
Fixed charge rate (%)	10.3	
Net annual energy production (MWh/MW/yr)	3,595	
Net capacity factor (%)	41.0	
TOTAL LCOE ($/MWh)	**229**	

Installed project data were gathered from the American Wind Energy Association project database (2016), and land-based wind project cost estimates were derived primarily from installed project data reported by Wiser and Bolinger (2016). These data were supplemented with outputs from NREL's cost models for wind turbine and balance-of-system components. Because of the absence of installed or operating offshore wind projects in the country, the offshore reference project data were estimated from installed 2015 global offshore projects, data collected from U.S.-proposed projects, and market data from the existing international offshore wind industry. The assumed wind resource regime and geospatial plant characteristics (e.g., water depth and distance from shore) for the offshore reference plant are comparable to that of sites on the U.S. North Atlantic Coast.

The three major component cost categories and many subcategories are represented in Figures ES1, ES2, and ES3, including wind turbine (e.g., wind turbine components), balance of system (e.g., development, electrical infrastructure, assembly, and installation), and financial costs (e.g., insurance and construction financing). The majority of the land-based project CapEx (71%) are in the turbine itself, whereas the turbine makes up only 32% of the fixed-bottom offshore and 22% of the floating offshore reference project CapEx.

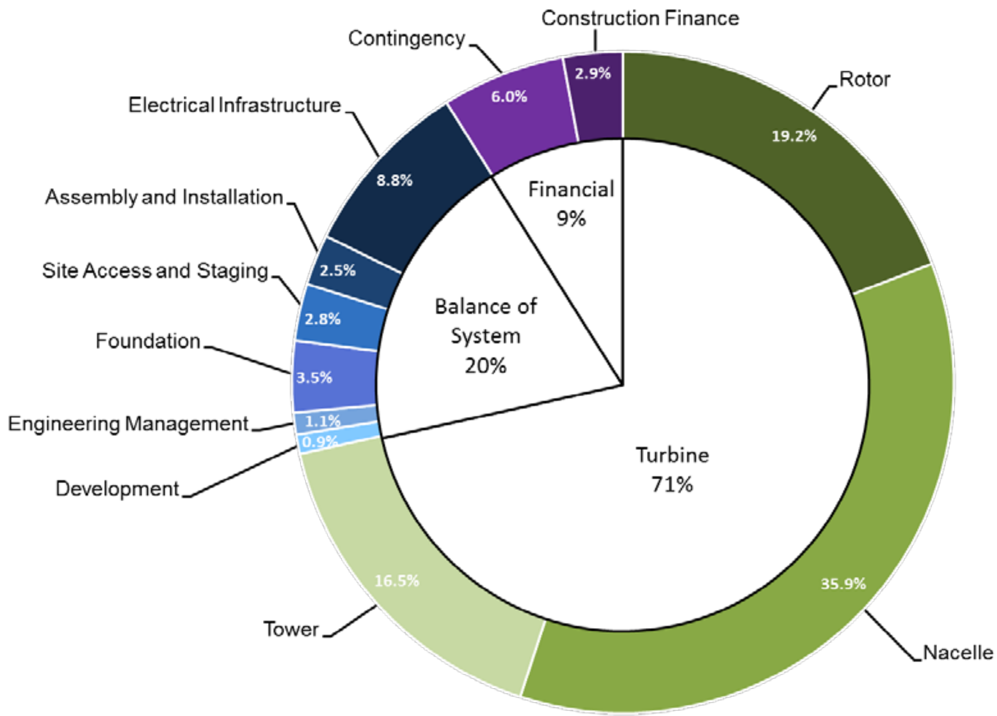

Figure ES1. Capital expenditures for the land-based reference wind plant project
Source: NREL

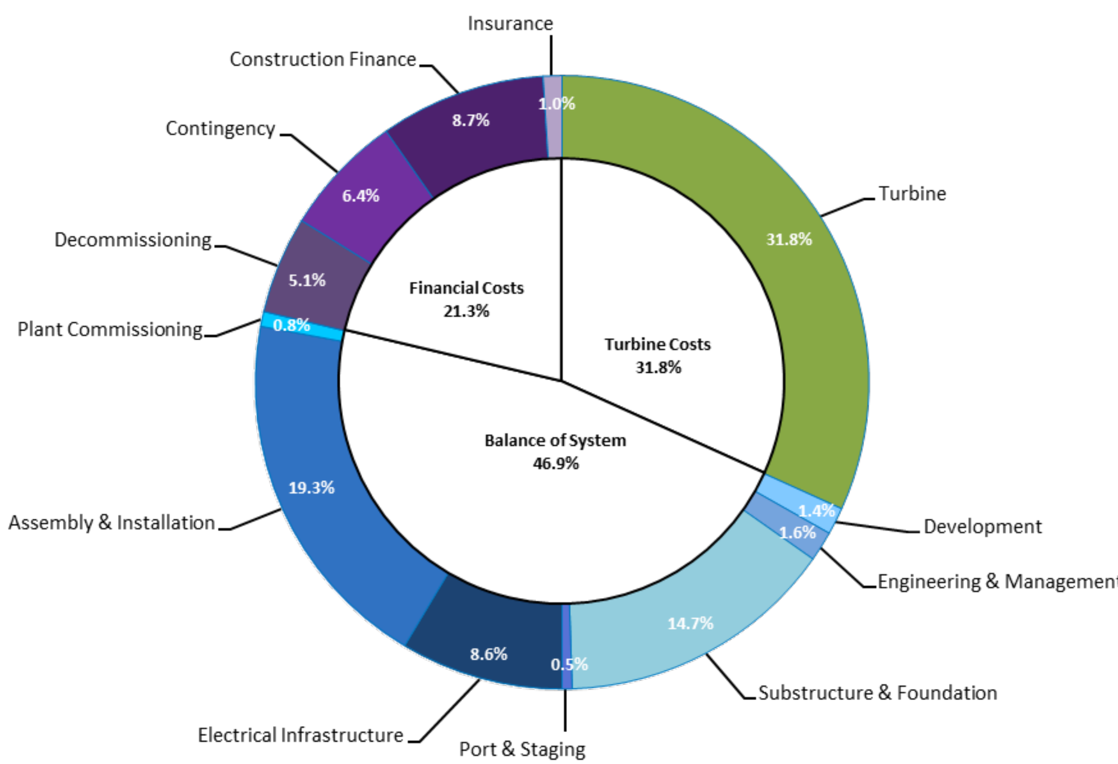

Figure ES2. Capital expenditures for the fixed-bottom offshore reference wind plant project
Source: NREL

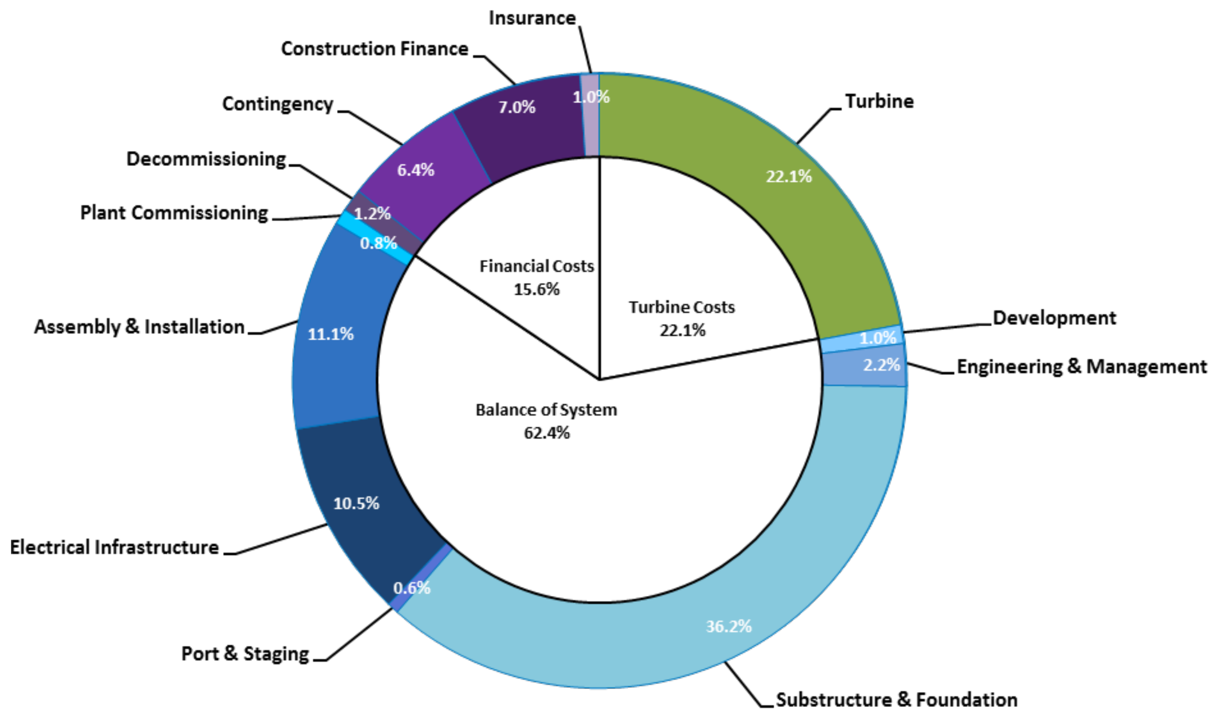

Figure ES3. Capital expenditures for the floating offshore reference wind plant project
Source: NREL

Figures ES4, ES5, and ES6 define the LCOE associated with the land-based and offshore reference plants and provide a range of independent, single-variable sensitivities showing how specific variables affect cost and performance. Reference project values of $61/megawatt-hour (MWh) for land-based wind, $181/MWh for fixed-bottom offshore wind, and $229/MWh for floating offshore wind rely on inputs summarized in Tables ES1, ES2, and ES3 and are identified by the vertical white line in these figures. Figures ES4, ES5, and ES6 also show the observed industry ranges for LCOE inputs and the resulting calculated impacts on LCOE. Clearly, the ranges for land-based and offshore wind LCOE inputs vary significantly (note the different axes in these figures). Both figures show the effect that capacity factor and CapEx have on the LCOE for both land-based and offshore wind projects. More detailed descriptions of the ranges and assumptions are included in the body of the report.

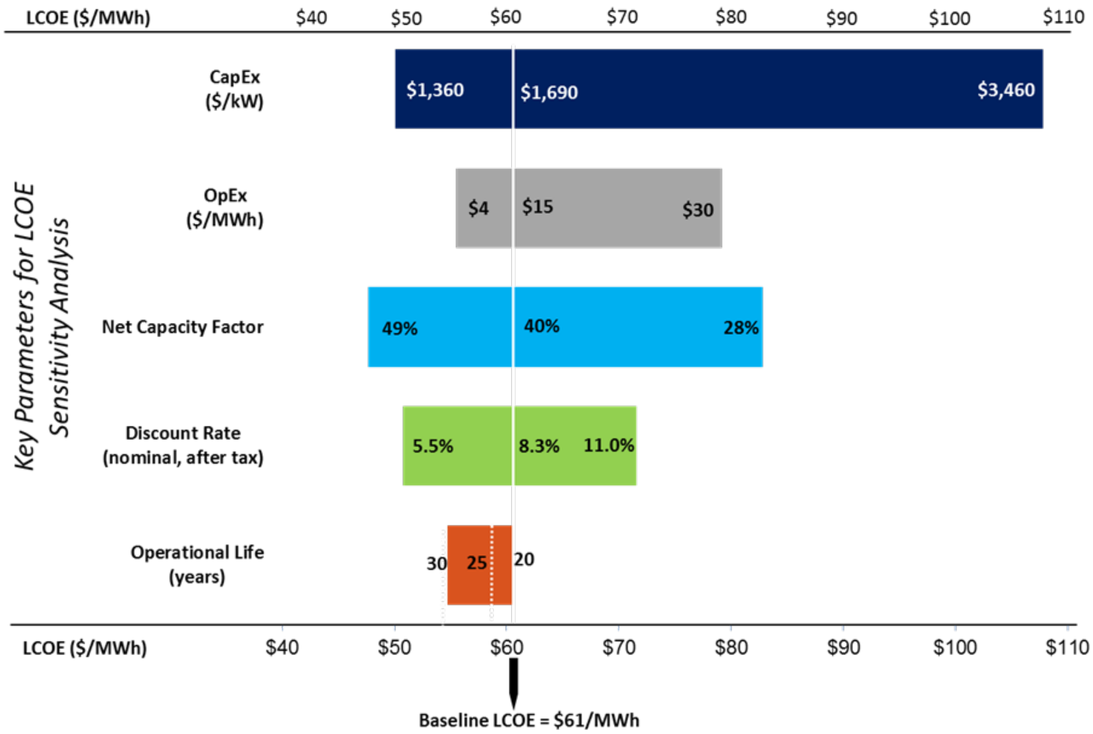

Figure ES4. Land-based wind plant assumptions and ranges for key LCOE input parameters
Source: NREL

Note: The reference LCOE represents the estimated LCOE for the NREL reference project. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the x-axis indicate how the LCOE will change as a given variable is altered, assuming that all others are constant. For example, as capacity factor decreases toward 28.5%, the LCOE shown on the x-axis will increase accordingly to approximately $85/MWh. As the operational life for the reference project moves toward 30 years, the LCOE will decrease to nearly $57/MWh.

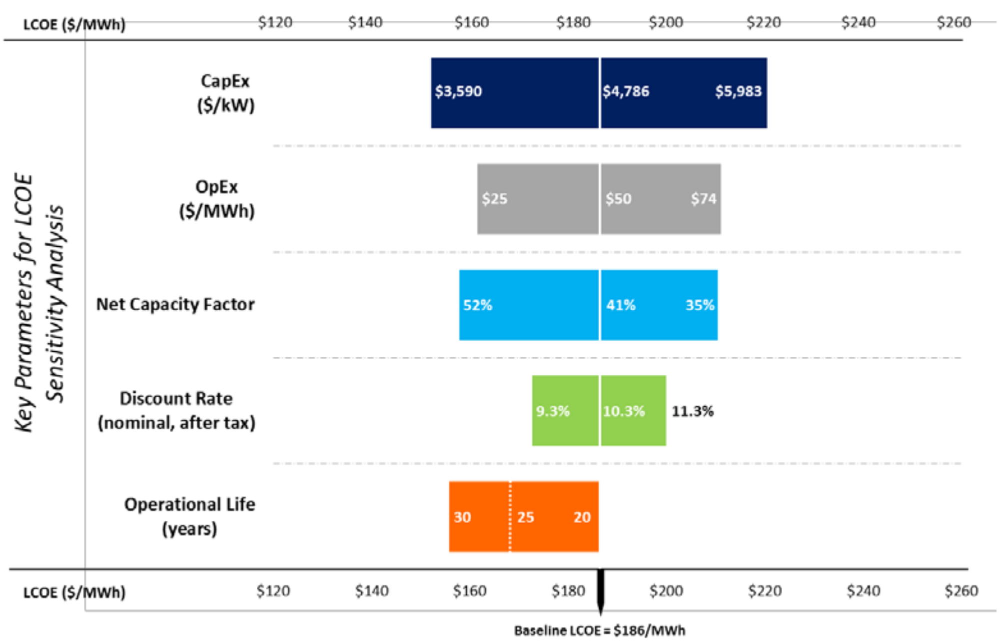

Figure ES5. Fixed-bottom offshore wind plant assumptions and ranges for key LCOE input parameters
Source: NREL

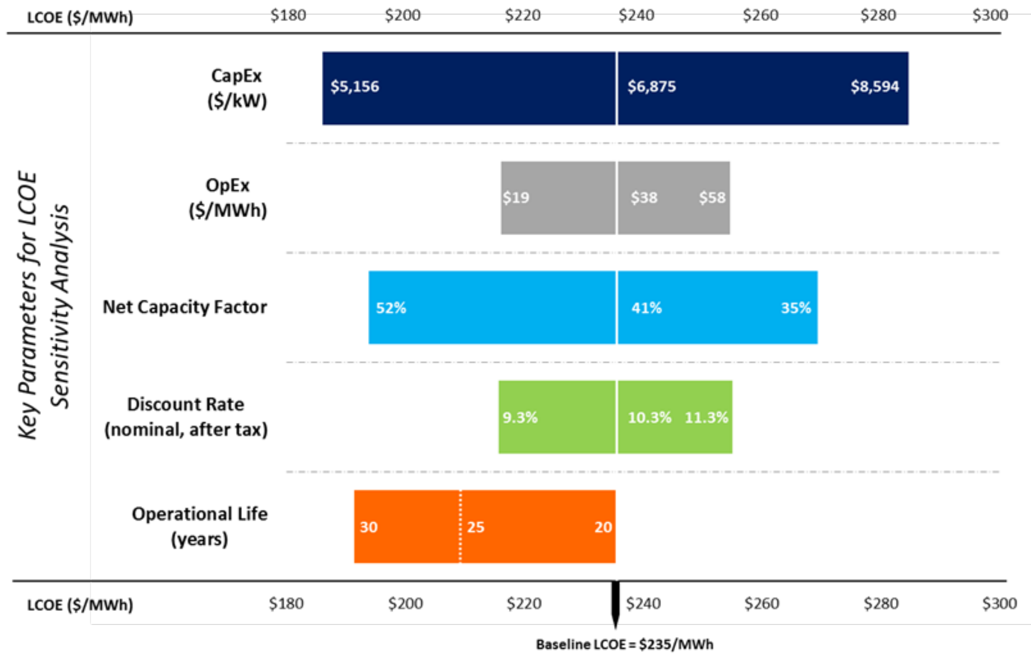

Figure ES6. Floating offshore wind plant assumptions and ranges for key LCOE input parameters
Source: NREL

From the data above as well as the full body of work detailed in this report, the authors have derived the following key conclusions:

- Land-based wind plant LCOE estimates continue to show a downward trend from the *2010 Cost of Wind Energy Review* (Tegen et al. 2012) to 2015. The reference project LCOE for land-based installations was observed to be $61/MWh,[1] with a range of land-based estimates from the single variable sensitivity analysis covering $48–$108/MWh.[2]
- Offshore plant costs show cost reductions as well. The fixed-bottom reference project offshore estimate is $181/MWh; the floating substructure reference project estimate is $229/MWh. These two reference projects give a single variable sensitivity range of $152–$285/MWh. This range is caused by the large variation in CapEx ($3,500–$8,500/kilowatts), which is partially a function of water depth and distance from shore, reported by project developers. Although offshore wind cost reductions were relatively modest through 2015, more recent European project bids or "strike prices" suggest that costs for offshore wind could fall further in the coming years.[3]

[1] As the production tax credit ramps down and expires permanently over the next years, it is likely that wind project weighted-average cost of capital or discount rate will be reduced as leverage increases. Assuming no fundamental shift in interest rates, the weighted-average cost of capital could drop below 7% corresponding to an LCOE of $56 assuming the 2015 reference project parameters.
[2] LCOE estimates reflect a cost to a wind plant developer and are not directly comparable with power purchase agreements that reflect sale of electricity. See text box in Section 4.9 for wind plant characteristics that yield LCOE that could be compared with power purchase agreement prices from $20/MWh to $30/MWh.
[3] See text box in Section 5.8 for discussion of recent European offshore wind plant strike price announcements.

- Sensitivity analysis shows that LCOE can vary widely based on changes in any one of several key factors; however, the variable with the most dramatic effect on LCOE is CapEx followed by net capacity factor—for both land-based and offshore projects.
- For land-based projects, regional variation in LCOE based on pairing wind turbine technology with wind resource conditions results in a range of LCOE from $39/MWh to $241/MWh, with estimated LCOE for projects installed in 2015 tending toward the lower end of this range, with estimated LCOE values from $50/MWh to $111/MWh.
- The three exogenous drivers of turbine prices—led by foreign exchange rate movements and followed by materials prices (and steel prices in particular) and subsequently energy prices—have had a relatively larger impact on turbine prices than the four endogenous drivers (e.g., labor costs, warranty provisions, profit margins, and turbine scaling), both leading up to and since the 2008 peak in wind turbine pricing.
- The relative influence of the exogenous drivers suggests that any shift away from current macroeconomic conditions, characterized by a prolonged period of dollar strength and commodity price weakness, may create challenges for further turbine price reductions, absent changes in technology or manufacturing processes that could reduce the material types and input quantities of wind turbines.

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1 Background

This report estimates the levelized cost of energy (LCOE) for land-based and offshore wind projects in the United States. LCOE is a metric used to assess the cost of electricity generation and the total plant-level impact from technology design changes, which can be used to compare costs of all types of generation. Although different methodologies exist to calculate LCOE, the method used for this analysis is described in *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (Short, Packey, and Holt 1995).[4]

In 2015, the National Renewable Energy Laboratory (NREL) expanded on Short's work by publishing the *Annual Technology Baseline* (ATB). The ATB (NREL 2016) provides a summary of current and projected cost and performance of primary electric-generating technologies in the United States, including renewable technologies. These cost and performance estimates are used in the Regional Energy Deployment System (ReEDS) model to create a set of possible standard scenarios for future U.S. electric sector evolution and are published to improve transparency of critical modeling input assumptions.

This report provides an update to the *2014 Cost of Wind Energy Review* (Moné et al. 2015b) and a look at the 2015 wind LCOE, turbine costs, financing, and broader market conditions. The 2015 report includes:

- Estimated LCOE for a representative, land-based wind project installed in a moderate wind resource located within the interior (hereafter referred to as "Interior") region of the United States in 2015
- Estimated LCOE for representative offshore, fixed-bottom, and floating projects, using NREL models and a database informed by projects installed in Europe for a representative site on the U.S. North Atlantic Coast
- Sensitivity analyses showing the range of effects that basic LCOE variables could have on the cost of wind energy for land-based and offshore wind power plants and NREL's historical, calculated LCOE estimates for land-based and offshore wind plants
- Estimated range of LCOE for land-based wind projects across the contiguous United States that were divided into five regions and based on geographically specific wind resource conditions paired with approximate wind turbine size characteristics
- An update on prior analysis (Bolinger and Wiser 2011) of the drivers of wind turbine prices in the United States to estimate and understand the relative contributions of various endogenous and exogenous drivers to the decline in wind turbine prices observed since 2010.

This report addresses a number of assumptions and cost variables, but does not include the full spectrum of drivers that affect wind energy prices. For example, it does not consider policy incentives (such as the production tax credit [PTC]),[5] factors from underlying economic conditions (such as an economic recession), the cost of building long-haul interstate transmission, or potential grid integration costs. These important variables can impact wind

[4] For an overview of cost-of-energy calculators and models, see Gifford, Grace, and Rickerson (2011).
[5] See *Implications of a PTC Extension on U.S. Wind Deployment* for further information (Lantz et al. 2014).

power costs by increasing or decreasing project costs, delaying projects, or halting projects altogether. Nevertheless, their exclusion is consistent with past economic analyses conducted by NREL (Lantz et al. 2012; Tegen et al. 2012) and others (Bloomberg New Energy Finance [BNEF] 2016a; Lazard 2016), as LCOE is not traditionally defined as a measure of all societal costs and benefits associated with power generation resources.

The standard *Annual Technology Baseline* LCOE equation, which is noted in Appendix B, can be simplified for each technology. For wind, the following equation is used to calculate LCOE:

$$\mathrm{LCOE} = \frac{(\mathrm{CapEx} \times \mathrm{FCR}) + \mathrm{OpEx}}{(\mathrm{AEP}_{\mathrm{net}}/1{,}000)} \tag{1}$$

where

LCOE = levelized cost of energy ($/megawatt-hour [MWh])

FCR = fixed charge rate (%)

CapEx = capital expenditures ($/kilowatt [kW])

$\mathrm{AEP}_{\mathrm{net}}$ = net average annual energy production (MWh/megawatt [MW]/year [yr])

OpEx = operational expenditures ($/kW/yr).

The first three basic inputs into the LCOE equation—capital expenditures (CapEx), operational expenditures (OpEx), and annual energy production (AEP)—enable this equation to capture system-level impacts from design changes (e.g., larger rotors or taller wind turbine towers). The fourth basic input—a fixed charge rate (FCR)—represents the amount of revenue required to pay the carrying charges[6] as applied to the CapEx on that investment during the expected project economic life on an annual basis.[7] For this analysis, the economic life of a wind project is assumed to be 20 years, consistent with industry turbine certification practices. All analysis and LCOE results are in constant 2015 dollars throughout the report unless otherwise noted.

The following sections of this report define the approach to calculating the LCOE following the respective NREL system cost breakdown structures (SCBSs) to organize data and provide a common terminology across varying technologies. The report describes each component of the LCOE equation (such as CapEx, OpEx, AEP, and FCR), the market context, and a range of data for typical U.S. wind projects in 2015. In this 2015 report, the authors first define the 2015 LCOE components for a land-based reference project using an installed weighted-average turbine sized of 2.0 MW, the average nameplate capacity installed in the United States in 2015. Next, we describe the 2015 LCOE components for offshore wind reference projects using 4.14-MW offshore turbines, the average nameplate capacity installed globally in 2015. Two additional sections discuss trends in real wind power LCOEs relative to trends in nominal terms and update prior analysis by Lawrence Berkeley National Laboratory (Bolinger and Wiser 2011, 2012) focused on characterizing the relative impact of wind turbine price drivers through 2015.

[6] Carrying charges include the return on debt, return on equity, taxes, and depreciation.
[7] The fixed charge rate does not allow for detailed analysis of specific financing structures; however, these structures can be represented through the use of a weighted-average cost of capital as the discount rate input.

2 Approach

This *2015 Cost of Wind Energy Review* applies a similar approach as the 2010, 2011, 2013, and 2014 reports (Tegen et al. 2012; Tegen et al. 2013; Moné et al. 2015a, 2015b). We used a number of data sources and models to estimate the cost of wind energy. All models and data have, at some point, been tested, documented, and verified within NREL, other national laboratories, universities, and industry to ensure that the methodology and tools are as accurate as possible. For land-based wind technology calculations, the United States installed almost 8,600 MW of new projects in 2015, bringing the total cumulatively installed capacity to just under 74 gigawatts (GW).[8] The available data from these wind projects provided a large sample of empirical data on plant costs and performance. In contrast, no commercial offshore wind technology was deployed in the United States for the period of analysis focus (calendar year 2015).[9] Accordingly, the market data supporting offshore cost-of-wind-energy estimates are limited to international projects and proposed U.S. projects. NREL's database of global offshore projects, in which the majority of projects are located in Europe, represents an extensive list of the installed projects that are used to create empirical representations and to derive cost data utilized in the analysis.

In addition to historical market data, we employed models to estimate disaggregated plant-level cost components. Therefore, detailed data are provided on the individual components that make up CapEx, OpEx, and estimated AEP for the reference projects defined here. Given the market and model data available, the general approach to estimating the levelized cost of wind energy includes:

1. Evaluating market conditions and data for projects that have been installed in the United States in a given year to understand total land-based CapEx, AEP, operating costs, and representative turbine technology. The primary sources for these data are the American Wind Energy Association (AWEA) database (undated) and the U.S. Department of Energy's (DOE's) *Annual Wind Technologies Market Report* data set (Wiser and Bolinger 2016). Representative turbine characteristics (i.e., rating, rotor diameter, and hub height) are taken as market averages. Accordingly, LCOE estimates reflect average empirical conditions to the extent possible.
2. Evaluating market conditions and data for projects that have been installed in Europe and Asia when considering offshore wind technology in a given year to understand total CapEx, OpEx, and representative turbine technology because no U.S. projects have been installed to date. AEP and balance-of-system (BOS) costs are modeled using the specified U.S. North Atlantic site conditions. The primary source for these data is NREL's internal Offshore Wind Database (OWDB) (NREL 2013) and the *2014–2015 Offshore Wind Technologies Market Report* (Smith, Stehly, and Musial 2015).
3. Supplementing available market data with modeled data based on a representative or reference project that reflects technology and project parameters for a given year. Two principal models are used in this assessment, NREL's wind turbine design Cost and Scaling Model (CSM) (Fingersh, Hand, and Laxson 2006; Maples, Hand, and Musial

[8] Note that not all of the data for these projects are publicly available.
[9] The U.S. first offshore wind project off the coast of Rhode Island was commissioned in late 2016.

2010) and the NREL 2015 CSM, which is being incorporated into NREL's Wind-Plant Integrated System Design and Engineering Model (WISDEM™) (Dykes et al. 2015). Both can be used to estimate the capital cost and AEP of a project based on turbine rated capacity, rotor diameter, hub height, and a representative wind resource. These models use scaling relationships at the component level (e.g., blade, hub, generator, and tower) that reflect the component-specific and often nonlinear relationships between size and cost. Both of these models provide additional component-level details for turbines (with user-defined parameters) and plants.

4. Combining the market data and modeled data described earlier to estimate the primary elements necessary to calculate LCOE (i.e., CapEx, OpEx, AEP, and FCR) and provide details about wind technology costs and performance that are aligned with market data but reported at a more detailed resolution. Unless specifically stated, all data and analysis used in this report are in 2015-nominal dollars, taking into account changes due to inflation from previous reports.

Two approaches to address LCOE variation around the land-based wind reference project are included. A sensitivity analysis in which independent LCOE input variables including CapEx, OpEx, capacity factor, project life, and weighted-average cost of capital (WACC) are varied based on ranges observed in 2015 market data illustrates a range of LCOE around the reference project and the relative impact of individual input variables. An analysis of regional cost of energy that pairs wind turbine parameters with site-specific wind resource conditions, estimates regional cost influences such as labor and materials, and estimates distance-based costs to access transmission infrastructure was conducted using data and methods similar to that of the reference project. LCOE estimates are reported for over 94,000 potential wind plant locations as well as locations where wind projects were installed in 2015.

A variety of factors influence wind turbine prices, and although some of these drivers are "endogenous" in the sense that they can be influenced by industry- and government-sponsored research and development programs and deployment-related learning, other "exogenous" drivers fall largely outside of the industry's control. As categorized in Bolinger and Wiser (2011, 2012), which explored seven different drivers behind the doubling in turbine prices from 2001 through 2008 and the subsequent decline through 2010, endogenous variables include (but are not necessarily limited to) labor costs, warranty provisions, and profit margins at turbine manufacturers and component suppliers, as well as turbine design changes like increased capacity, hub height, and rotor diameter. Exogenous variables include (but are not necessarily limited to) prices for raw materials and energy and movements in foreign exchange rates.

Section 7 updates and revises the analysis behind Bolinger and Wiser (2011, 2012) to gain insight into the extent to which each of these endogenous and exogenous variables have contributed to turbine price declines since 2010 (when the analysis underlying the original report left off). In addition to updating (and revising) the previous analysis, it also evaluates one potential future scenario in which turbine prices could be pressured higher by adverse movements in commodities prices and exchange rates in particular (i.e., a reversal of the extended period of commodity price weakness and dollar strength that has benefited turbine prices in recent years).

3 System Cost Breakdown Structure

As domestic and global wind markets mature, data for component-level costs are increasingly available. To manage and organize this component-level cost data, NREL has developed a SCBS for wind projects that provides the ability to view components of a wind plant at varying degrees of cost detail. In Figure 1, a broad overview of plant costs is shown from the top down. From the bottom up, individual component costs are grouped into systems and their costs roll up to higher-level costs until the plant level is reached. Overall, the SCBS deconstructs the total expenditures of a wind project down to six levels and includes more than 300 components.

3.1 System Cost Breakdown Structure Description

The SCBS provides structured and consistent breakdowns of a wind project into smaller, more specific components.[10] It provides a standardized approach to characterizing total lifetime expenditures for wind projects at the component level, including both physical costs (e.g., materials, labor, and equipment) and financial costs (e.g., insurance during construction, profit, and carrying charges). Each descending level of the SCBS hierarchy represents an increasingly detailed look at the project components. For example, total lifetime expenditures can be deconstructed into two "level 1" components: CapEx and OpEx. CapEx can be further deconstructed into three "level 2" components: turbine, BOS, and financial costs (see Figure 1). Financial costs break down further to construction financing, insurance during construction, decommissioning (offshore), and so on. The sum of the costs across all components at a given level should equal the cost of the components in the level above them provided that all fields have data. For example, the sum of turbine costs, BOS costs, and financial costs (level 2) should equal the CapEx for a given project (level 1).

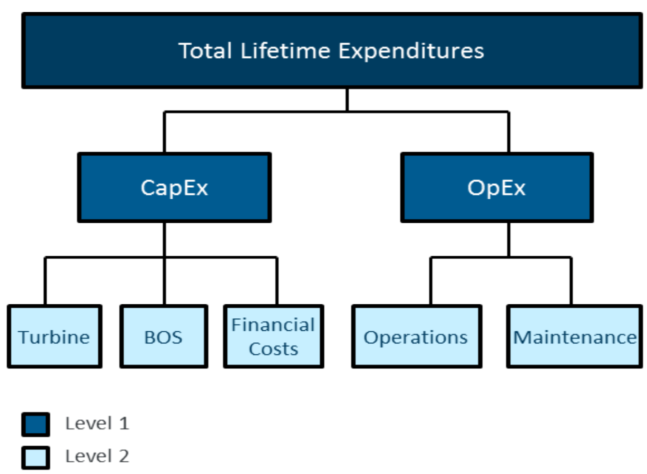

Figure 1. Levels 1 and 2 of the SCBS
Source: NREL

The various elements of CapEx and OpEx follow the SCBS categories throughout this report. The full detailed explanation of the land-based and offshore wind SCBS, including descriptions of each component category, is included in Appendix E and F of the *2013 Cost of Wind Energy Review* (Moné et al. 2015a).

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[10]Although the SCBS is similar to a work breakdown structure, it serves a different purpose. A work breakdown structure is typically process- or product-oriented, whereas the SCBS is cost-oriented, with a focus on representing the components of a project that contribute to capital and operational expenditures.

4 Land-Based Wind

The turbine characteristics utilized in the land-based wind reference project were derived from DOE's *2015 Wind Technologies Market Report* (Wiser and Bolinger 2016). Reference project wind turbine and component costs are based on a hypothetical turbine that comprises the average parameters—nameplate capacity, rotor diameter, and hub height—of turbines that were installed in the United States in 2015. This type of turbine rests on a standard spread-foot foundation design and incorporates a three-stage planetary/helical gearbox feeding a high-speed asynchronous generator. The 2015 reference project wind regime is intended to reflect a moderate wind resource site in the Interior region of the United States that is consistent with prior versions of this report.

4.1 Land-Based Installed Projects in 2015

In 2015, the U.S. wind energy market installed 68 projects totaling 8,598 MW (Wiser and Bolinger 2016). Figure 2 shows the general size and location of the installed projects in the five regions outlined in the *2015 Wind Technologies Market Report* (Wiser and Bolinger 2016). The majority of installed megawatts occurred in Texas and 62% of all megawatts were installed within a 300-mile radius of the state's panhandle. Figure 3 shows the top five states for installed megawatts in 2015, with a substantial majority installed in Texas and Oklahoma.

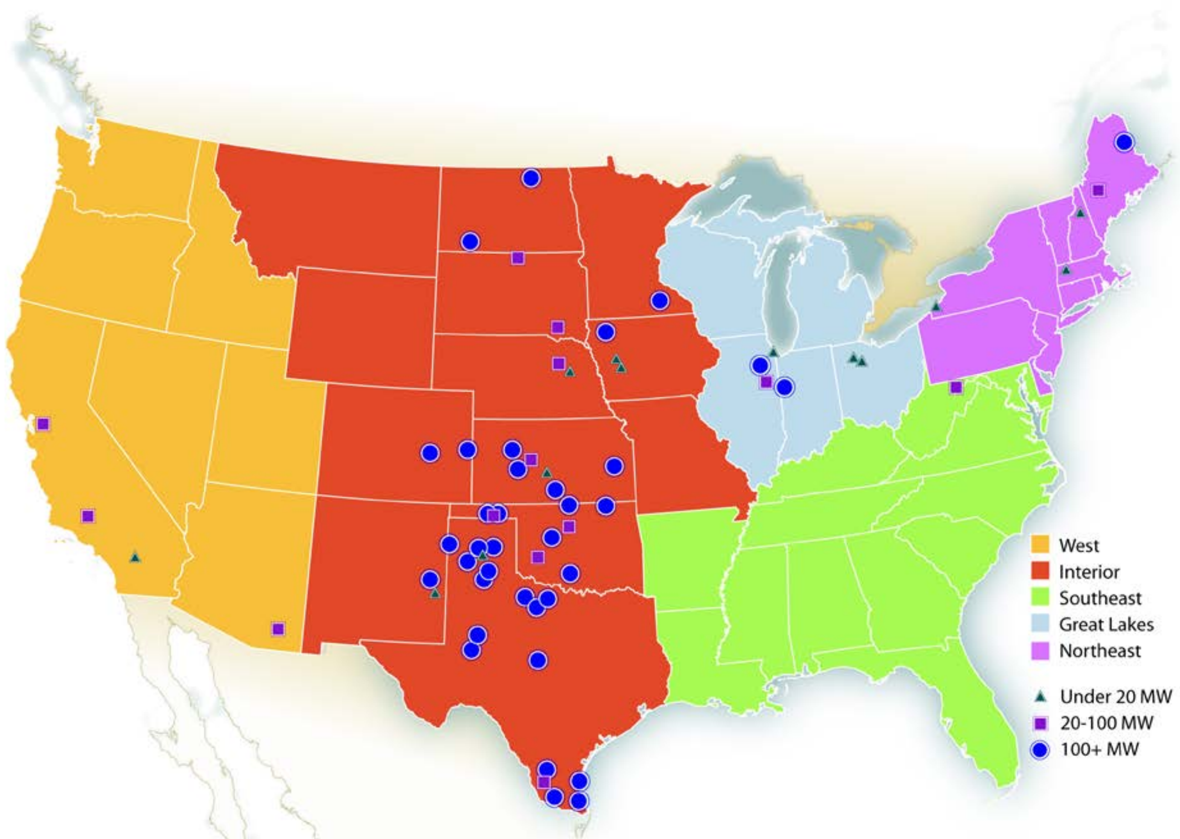


Figure 2. Installed U.S. land-based wind projects in 2015
Source: AWEA Projects Database, NREL

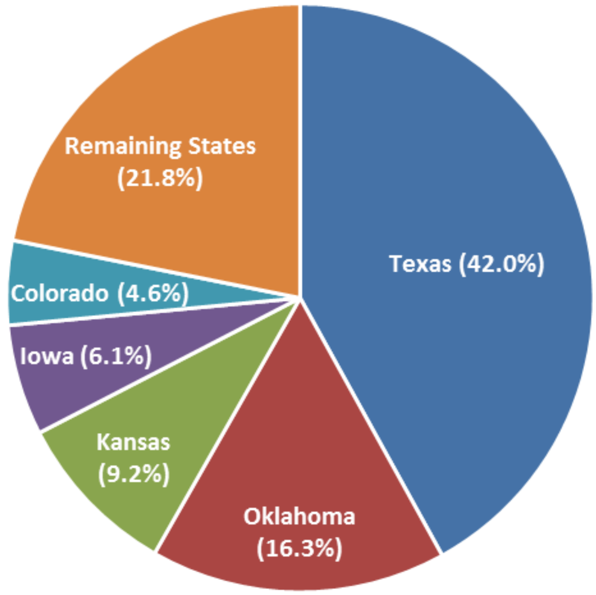


Figure 3. Installed capacity by project location and state (2015)
Source: AWEA Projects Database

Although there are dozens of global wind turbine manufacturers, the U.S. market is dominated by three in particular: GE Energy, Siemens, and Vestas. Figure 4 shows that GE installed the most capacity in the United States in 2015, at 40% of total capacity installed. In 2015, Vestas installed 33%, and Siemens installed 14%, with all other turbine capacity being installed by other original equipment manufacturers (OEMs).

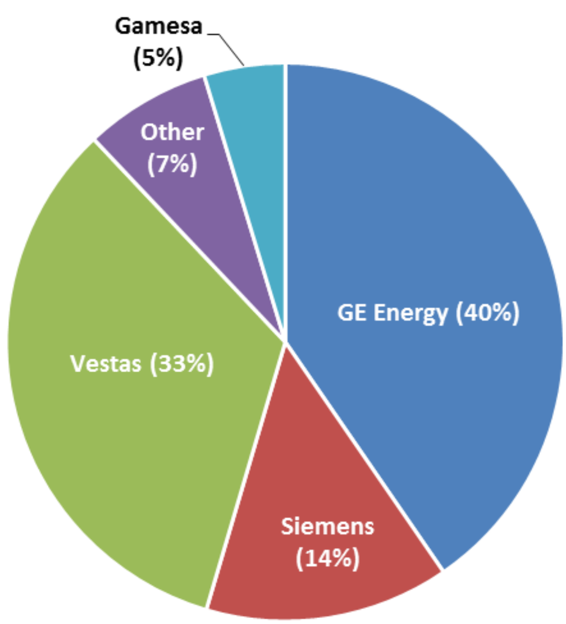


Figure 4. Installed capacity by OEM supplier and percentage (2015)
Source: AWEA Projects Database

4.2 Land-Based Cost of Wind Energy in 2015

The land-based wind reference project was created to calculate the LCOE using an average of turbine characteristics of all 68 wind projects installed in 2015. The land-based wind reference project consists of 100 2.0-MW turbines (200 MW total installed capacity). The capacity-weighted average CapEx[11] of all 2015 installed wind projects was calculated to be $1,690/kW, with total pretax OpEx at $51/kW/yr. The U.S. land-based reference project AEP was calculated to be 3,494 MWh/MW/yr, which results in a net capacity factor of 39.9%. Given these inputs, as well as the additional variables considered to reflect the reference project summarized in Table 1, the resulting LCOE is $61/MWh.

Table 1. Summary of Inputs and Reference Project LCOE for 2015 Land-Based Installations

	2.0-MW Land-Based Turbine ($/kilowatt [kW])	2.0-MW Land-Based Turbine ($/megawatt-hour [MWh])
Turbine capital cost	1,209	33.2
Balance of system	330	9.1
Financial costs	151	4.1
Capital expenditures (CapEx)	**1,690**	**46.4**
Operational expenditures (OpEx; $/kW/yr)	51	14.6
Fixed charge rate (%)	9.6	
Net annual energy production (MWh/MW/yr)	3,494	
Net capacity factor (%)	39.9	
TOTAL LCOE ($/MWh)	**61**	

[a] Sources are listed in the relevant sections of this report related to the specific cost components.

4.3 Capital Expenditures for Land-Based Wind

The weighted-average CapEx data are published annually by DOE, with the latest version being the *2015 Wind Technologies Market Report* (Wiser and Bolinger 2016). Previous analysis has applied the NREL CSM (Fingersh, Hand, and Laxson 2006; Maples, Hand, and Musial 2010) to estimate component-level costs. This year, a new NREL 2015 CSM was used to conduct the cost analysis and calibrate to the market-based total cost estimates from the data set used by Wiser and Bolinger (2016). The NREL 2015 CSM (Dykes and Moné [forthcoming]), like its 2006 predecessor, uses curve fits to commercial turbine component design and cost data while providing the ability to adjust inputs such as overhead, profit, and transportation. The new model is intended to more accurately reflect current wind technology.

Figure 5 illustrates the breakdown of CapEx for the NREL land-based reference project. In the figure, the CapEx component percentages highlighted in shades of green capture the turbine

[11] CapEx costs represent the total cost of building a plant and do not include project-specific financing or escalation costs, which can vary with risk perception, inflation expectations, and other factors. Instead, the financing and escalation costs are represented by the FCR in modeling as described in Section 4.6.

capital cost, the percentages highlighted in blue capture the BOS share of capital costs, and the components highlighted in purple capture the financial capital expenditures. For information on the assumptions and inclusions of the individual components, see the *2013 Cost of Wind Energy Review* (Moné et al. 2015). Some costs, such as transportation, are rolled up into higher categories (such as nacelle and blades) because the specific data is difficult to obtain based on a theoretical reference site and an unspecified turbine manufacturer.

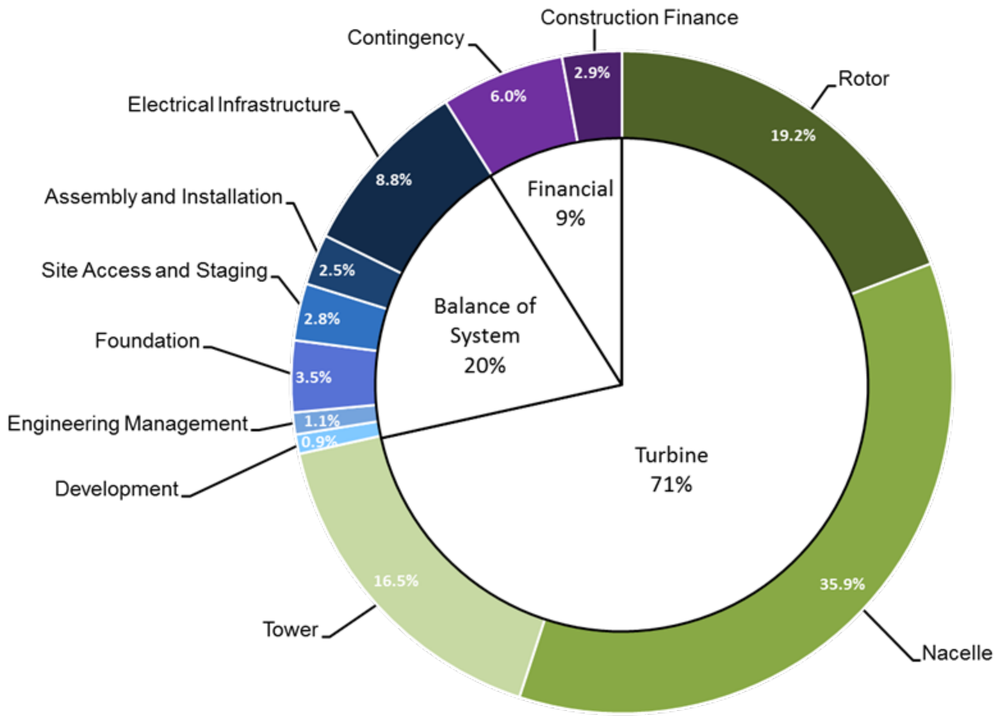


Figure 5. Capital expenditures for the land-based wind reference project
Source: NREL

Table 2 summarizes the costs for individual components (including their contribution to LCOE) for average turbine characteristics used in the reference project, based on a project that uses 2.0-MW turbines. Data sources for this table are described in greater detail in Appendix A.

Table 2. Land-Based LCOE and CapEx Breakdown

	2.0-MW Land-Based Turbine ($/kW)	2.0-MW Land-Based Turbine ($/MWh)
Rotor Module	**324**	**8.9**
Blades	205	5.6
Pitch assembly	70	1.9
Hub assembly	49	1.3
Nacelle Module	**605**	**16.6**
Nacelle structural assembly	59	1.6
Drivetrain assembly	234	6.4
Nacelle electrical assembly	279	7.7
Yaw assembly	33	0.9
Tower Module	**279**	**7.7**
TURBINE CAPITAL COST	**1,209**	**33.2**
Development cost	16	0.4
Engineering management	18	0.5
Foundation	59	1.6
Site access and staging	47	1.3
Assembly and installation	42	1.2
Electrical infrastructure	148	4.1
BALANCE OF SYSTEM	**330**	**9.1**
Construction financing cost	49	1.3
Contingency fund	102	2.8
FINANCIAL COSTS	**151**	**4.1**
TOTAL CAPITAL EXPENDITURES	**1,690**	**46.4**

Wind turbine costs for utility-scale wind projects installed in 2015 ranged from $850/kW to $1,250/kW (Wiser and Bolinger 2016). Because of CapEx variability, estimates for the turbine component costs were established using the NREL 2015 CSM. BOS costs were estimated using NREL's land-based BOS model, which utilizes scaling relationships and costs derived from detailed data obtained through a major engineering, procurement, and construction firm active in the wind industry. These data provide a basis for understanding the underlying impacts of turbine component designs on the BOS costs. Construction financing was estimated at 3% and project contingency at 6% of CapEx, which is consistent with industry reporting.

4.4 Operational Expenditures for Land-Based Wind

Operational expenditures for this project, which are considered on an annual basis, reflect estimates from 154 projects installed to date, of which 71 have 2015 data included in the analysis

(Wiser and Bolinger 2016). As Wiser and Bolinger state, it is difficult to get actual project-level operation and maintenance (O&M) costs especially for projects installed during the previous year (2015 in this case) because of the lack of publicly available data. OpEx costs are generally expressed in two categories: operations, which include discrete, known operations costs (e.g., scheduled plant maintenance, rent, land lease costs, taxes, utilities, and insurance payments) that typically do not change as a function of how much electricity is generated; and maintenance, or variable OpEx, which includes unplanned maintenance of either the plant or turbine, scheduled turbine maintenance, and other costs that may vary throughout the project life as a function of how much electricity is generated. For simplicity, annual OpEx can be converted to a single term and expressed as either dollars per kilowatt per year ($/kW/yr) or dollars per megawatt-hour ($/MWh). This analysis uses the dollars-per-kilowatt-per-year convention.

The operation values reported to be $15/kW/yr excluding land lease costs at $8/kW/yr were estimated from NREL's Jobs and Economic Development Impact model. Annual maintenance estimates were calculated from recent estimates of operating costs for projects built since 2000. Wiser and Bolinger (2015) reported a pretax average maintenance value of $28/kW/yr for projects installed since 2010. This value generally incorporates the costs of wages and materials associated with maintaining the turbines at a facility, but likely excludes other elements such as general operations, insurance, taxes, and depreciation.[12] A report by Cohen et al. (2008) uses the term "levelized replacement costs," which supports the major turbine components and replacement costs that go into the maintenance estimates.

The original analysis was conducted by researchers across NREL and other laboratories in the wind industry who worked together to validate the calculation and support these pricing levels. Further information is provided in *Wind Vision: A New Era for Wind Power in the United States* (DOE 2015b). For the *2015 Cost of Wind Energy Review*, the O&M number was escalated from the original *Wind Vision* report using the reported inflation from the Bureau of Labor Statistics' (2016), resulting in a total pretax OpEx of $51/kW/yr and summarized in Table 3. It should be noted that, given the scarcity and unpredictable quality of the data, OpEx can vary substantially among projects (Wiser and Bolinger 2016), and the data presented here may not fully represent the challenges that OpEx present to the wind power industry.

Table 3. Land-Based Wind Reference Project OpEx

	2.0-MW Land-Based Turbine	2.0-MW Land-Based Turbine
Operations	$15/kW/yr	$4.3/MWh
Land lease cost	$8.0/kW/yr	$2.3/MWh
Maintenance	$28.0/kW/yr	$8.0/MWh
OpEx	**$51/kW/yr**	**$14.6/MWh**

[12] Alternatively, if expressed in dollars-per-megawatt-hour terms, operation and maintenance estimates in 2014 ranged from $5 to $20/MWh (based on plants with a commercial operation date of 2010), with the 2014 operation and maintenance baseline estimate of $9/MWh (Wiser and Bolinger 2015).

4.5 Annual Energy Production and Capacity Factor for Land-Based Wind

The AEP for this analysis was computed using the NREL CSM (Fingersh, Hand, and Laxson 2006; Maples, Hand, and Musial 2010). The model creates an idealized power curve based on the turbine design (Table 4) and then computes annual energy capture and related factors, such as capacity factor, for a wind project that is specified by the input parameters (Table 4). Aside from the turbine rated power, rotor diameter, and hub height, input parameters are held constant for the annual LCOE calculations, allowing the differences in turbines and financing, not project variability, to influence the results.

Table 4. Reference Land-Based AEP Input Assumptions

Turbine Parameters	
Turbine rated power (MW)	2.0
Turbine rotor diameter (m)	102.0
Turbine hub height (m)	82.1
Maximum rotor tip speed (meters per second [m/s])	80
Tip-speed ratio (TSR) at maximum coefficient of power (C_p)	8
Drivetrain design	Geared
Cut-in/cut-out wind speed (m/s)	4/25
Rotor peak C_p	0.47
Wind Resource Characteristics	
Annual average wind speed at 50-m height (m/s)	7.25
Weibull K	2
Shear exponent	0.143
Elevation (meters above sea level)	450
Losses	
Losses (i.e., array, energy conversion, and line)	15%
Availability	98%

4.5.1 Turbine Parameters

Turbine parameters are characteristics that are specific to the turbine and independent of the wind resource characteristics. These parameters consist not only of turbine size (such as rated power, rotor diameter, and hub height), but also of turbine operating characteristics (such as coefficient of power [C_p], maximum tip speed, maximum tip-speed ratio (TSR), and drivetrain design). Because the three-stage planetary/helical gearbox with a high-speed asynchronous-generator-style drivetrain topology dominates the U.S. market, this type of drivetrain was selected for the baseline turbines used in this analysis. For specific approaches regarding additional turbine parameters (e.g., power curves), see the *2010 Cost of Wind Energy Review* (Tegen et al. 2012).

4.5.2 Wind Resource

The average wind speed can vary from project to project across the United States. The annual average wind speed chosen for the reference project analysis, consistent with prior reports, was 7.25 meters per second (m/s) at 50 meters (m) above ground level (7.79 m/s at a hub height of 82.1 m). This wind speed is intended to be generally indicative of the wind regime for projects installed in moderate-quality sites in the Interior region of the United States (from Minnesota to Texas). An elevation of 450 m above sea level was applied based on this concept of using a representative site that would have a similar altitude to a project located within the interior of the country. The elevation above sea level, coupled with a hub height of 82.1 m, results in an air density of 1.163 kg/m^3 at the reference project site.

4.5.3 Losses

Although some losses can be affected by turbine design or wind resource characteristics, they are treated as independent of any other input in this simplified analysis. Types of losses accounted for here include array wake losses, electric collection and transmission losses (from the substation to the point of interconnection), and blade soiling losses, totaling 15%. An availability of 98% was used, indicating that the wind project is ready to produce power between wind turbine cut-in and cut-out wind speeds 98% of the time. Net average annual energy production (AEP_{net}) is calculated by applying all losses to the gross AEP. As a point of reference, historical, net capacity factors have ranged from 28.5% to 49.5% (Wiser and Bolinger 2016). Table 5 shows the AEP, capacity factors, losses, and availability for the land-based reference turbine operating in 2015.

Table 5. Land-Based Wind Turbine AEP and Capacity Factor Summary

	2.0-MW Land-Based Turbine
Gross AEP (MWh/MW/yr)	4,194
Gross capacity factor (%)	47.9
Losses and availability (%)	16.7
AEP_{net} (MWh/MW/yr)	3,494
Net capacity factor (%)	**39.9**

4.6 Land-Based Wind Finance

This section describes the financing assumptions for the report's representative land-based wind reference project in the United States in 2015. It is important to distinguish between financing assumptions and financial costs. Financial costs, which are part of CapEx according to the SCBS, include items such as insurance, contingency, and reserve accounts. Financing assumptions, on the other hand, refer to the cost of interest and other carrying charges, corporate taxes, and depreciation (represented by the FCR in this report), which are applied to the total CapEx. To capture the financing structure and costs, a fixed charge rate, which is detailed in Section 4.6.3, was used for the LCOE equation.

4.6.1 Overview of U.S. Land-Based Wind Financing Trends

In 2015, the wind industry continued the upward trend from 2014 by commissioning 68 projects totaling 8,598 MW of new wind energy capacity. These projects were likely committed and financed between late 2013 and early 2015. AWEA estimates that more than $14.7 billion in financing was raised in the wind sector for new projects in 2015 (AWEA 2016).

Successful financing in the U.S. wind energy industry requires structures that can monetize production tax credits. Historically, the PTC has been the primary federal policy support mechanism available for wind energy projects and currently provides a $23/MWh (2.3 ¢/kWh) incentive for the first 10 years of a wind project's operation. In 2015, Congress passed an extension of the expired PTC for 5 years. The current version of the PTC maintained its level through 2016 and then begins a phase-down period to 80% of its historical value in 2017, 60% in 2018, and 40% in 2019. New wind projects qualify for the PTC as long as construction begins before the end of the specified periods (Internal Revenue Service 2016).

Beyond public-policy-based tax credits and loan guarantees, a wind project becomes attractive for financing after obtaining a long-term (e.g., 20-year) power purchase agreement (PPA) with a creditworthy offtaker. According to AWEA's annual report, over the past 5 years nearly $13 billion has been invested annually in new wind projects, and for 2015 the amount increased slightly, from 2014 (AWEA 2016). Wind energy project financing typically comprises a blend of tax equity and debt, as shown in Table 6 (AWEA 2016).

Table 6. Tax Equity and Debt for New and Existing Wind Projects

Year	Tax Equity (billion $)	Debt (billion $)
2013	3.1	2.4
2014	5.8	2.7
2015	5.9	2.9

At the project level however, industry sources report that many wind projects commissioned in 2015 were financed with primarily tax equity and back leveraged cash (sponsor equity). This is in contrast to a more traditional project finance structure for power generation that might involve 60% long-term project debt and 40% equity (Lazard 2016). For wind projects, tax equity and permanent debt at the project level are mutually exclusive due to the collapse of any market consensus on the extent to which lenders who are ahead of tax equity in the capital structure should forbear from foreclosing on the project in a default scenario long enough for the tax equity investors to reach a target return. A survey of industry professionals indicated that 40 wind deals were awarded in 2015 involving 17 tax equity investors, amounting to nearly 5,700 MW of wind capacity and close to $6.4 billion in tax equity. Sponsors generally prefer the well-understood partnership flip model (Martin 2016), wherein the tax equity investor receives a high percentage of the cash and tax benefit until a specified return is achieved at which time the ownership "flips" back to the sponsor. Based on discussions with developers and financiers, NREL understands that tax equity comprises approximately 50% to 60% of the total capital structure for a typical wind project.

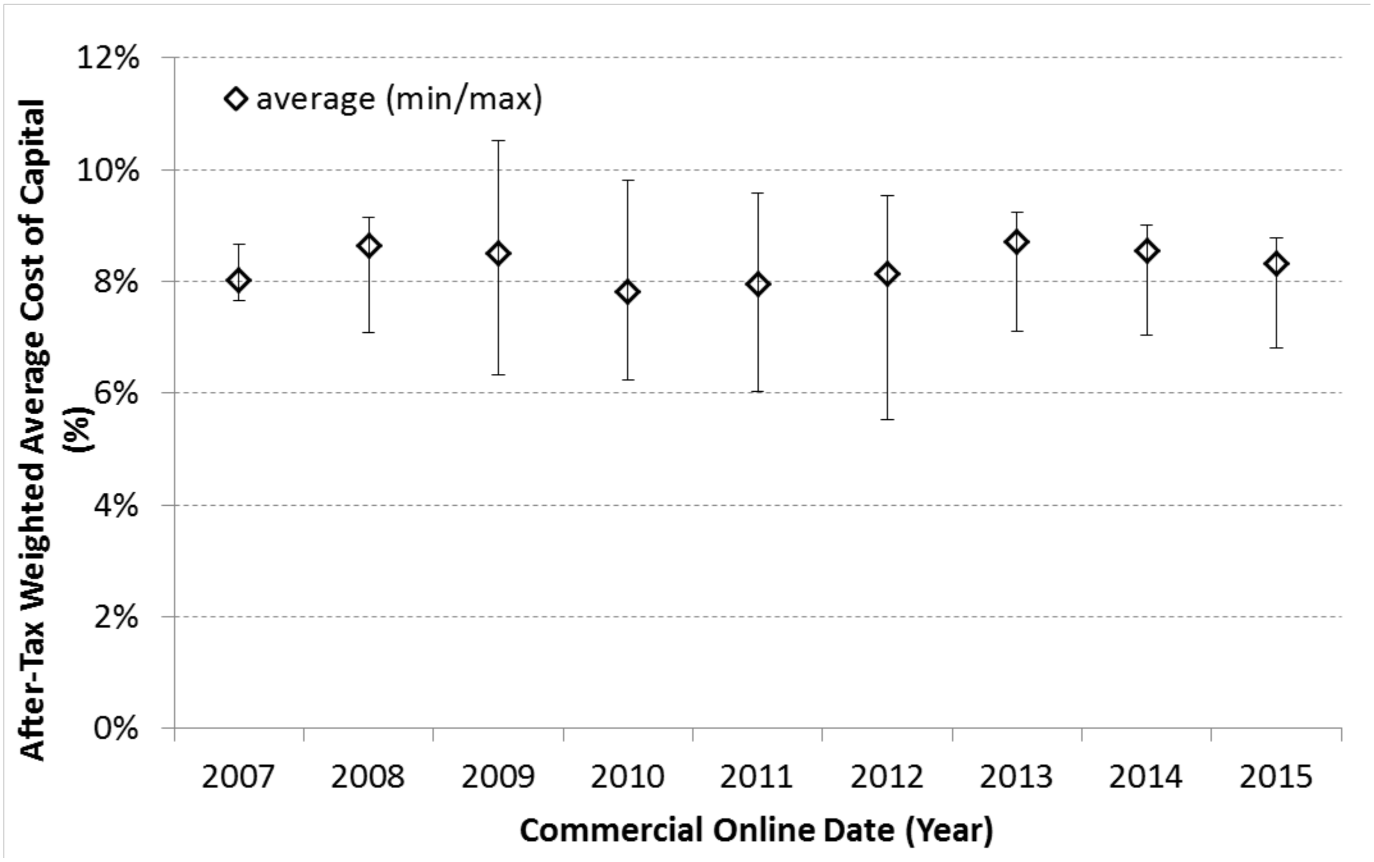
4.6.2 Discount Rate

A number of different metrics can be used in the economic evaluation of wind energy. Typically, various financial terms, such as the cost of debt or equity, are implicitly captured in the discount rate, which is in turn used to estimate the cost of energy (COE). For this analysis, the discount rate is calculated as the after-tax WACC and it is presumed that the reported yields for equity are after-tax yields and can be used directly in the WACC calculation in this analysis. The cost of debt (as a value) is also reported, but because interest on debt is tax deductible, an effective corporate marginal tax rate to determine an after-tax cost of debt for the discount rate calculation presented in this report is used. The cost of capital data collected and described in Section 4.6.1gives a basis for WACC assumptions for the representative wind project in 2015. Each actual project, however, has a unique risk profile, financing terms, and ownership structure. For this reason, a single WACC representing the entire fleet of 2015 wind installations should be viewed cautiously and used to illustrate general market trends and conditions only.

In financial modeling, corporate tax rates are often presented as a composite, or effective, tax rate. This rate is calculated from a blend of the highest marginal corporate tax rate of 35% and an approximate typical state corporate tax rate. Because state taxes are deductible expenses on federal tax returns, the blended rate is represented as 35% + 7.7% × (100% – 35%) = 40%. Wind projects are often organized as disregarded entities for tax purposes (i.e., no taxes are paid by the project entity) and taxes are paid further up the organizational structure at some corporate level. So-called double taxation may occur for these corporations when the shareholders also pay taxes on the corporation's net income.

The inflation rate, which is different than the rate included in the previous version of this analysis and report, has been set to 2.5%. This rate aligns with the inflation rate provided in NREL's *Annual Technology Baseline* (NREL 2016) that is used for future LCOE projections. Discount rates are initially calculated in nominal after-tax dollars, and an estimate of inflation is used to calculate a discount rate in real after-tax dollars. If an investor targets a nominal 8% return in an environment with inflation at 2%, the net return to the investor—the real after-tax return—is just under 6%.

For the base case, the nominal discount rate was estimated using five primary financing structures and assumptions detailed in an International Energy Agency (IEA) Wind Task 26 report titled *Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the European Union, and the United States: 2007–2012* (Vitina et al. 2015). The "national average" numbers include ranges and are shown in Figure 6 and Table 7. These values reflect a blend of the five financing structures and a review of the 3-month London Interbank Offered Rate and 15-year swap rates published by the Federal Reserve Bank.



Source: Lawrence Berkeley National Laboratory

Figure 6. Weighted average cost of capital for projects installed from 2007 to 2015[13]

Table 7. 2015 Land-Based Discount Rates Using the After-Tax WACC

Nominal Discount Rate (After Tax)	Real Discount Rate (After Tax)
8.3%	5.7%

Although the PTC is a critical component for wind projects installed in 2015, it is likely to change in the future.[14] Research has shown that one likely outcome of the termination of the PTC is increased project leverage, which will reduce the higher-cost tax-equity portion of project finance. This shift of capital structure is expected to partially offset the impact of the lack of PTC (Bolinger 2014). For example, assuming that project leverage increases from 40% to 60% results in a reduction in nominal after-tax WACC of over 1-percentage point (Mai et al. 2016).

[13] Published in 2015 (Vitina et al. 2015) and updated by Lawrence Berkeley National Laboratory for years 2013–2015.

[14] "In December 2015, Congress passed a 5-year phased-down extension of the PTC. To qualify, projects must begin construction before January 1, 2020. In May 2016, the IRS issued guidance allowing four years for project completion after the start of construction, without the burden of having to prove continuous construction. In extending the PTC, Congress also included a periodic reduction in the value of the credit for projects starting construction after 2016. Specifically, the PTC will phase down in increments of 20 percentage points per year for projects starting construction in 2017 (80% PTC), 2018 (60%), and 2019 (40%)" (Wiser and Bolinger 2016).

Assuming no fundamental shift in interest rates, average WACC for wind projects installed in the United States could decrease from 8.3% to less than 7%.

4.6.3 Economic Evaluation Metrics

In the economic evaluation of wind energy investments there are two important metrics: the capital recovery factor (CRF) and FCR. The FCR represents the amount of revenue required to pay the carrying charges[15] as applied to the CapEx on that investment during the expected project economic life on an annual basis.[16] The FCR is based on the CRF but also reflects corporate income taxes and depreciation. The ATB methodology was used to calculate the FCR and the equations for both the CRF and FCR are in Appendix B.

The CRF is defined as "the uniform periodic payment, as a fraction of the original investment cost that will fully repay a loan including all interest, over the term of the loan" (Short, Packey, and Holt 1995). The CRF can be thought of as the recurring fixed payment over the life of a loan common to most types of mortgages. For example, a $100 loan at 8% interest amortized over 20 years requires a constant annual payment of $10.18 (equivalent to the CRF). Notably, the CRF ignores the impact of corporate income taxes, thus is applicable to a no-tax investment scenario such as from a government investment.

U.S. wind projects in 2015 had the opportunity to benefit from accelerated depreciation (Modified Accelerated Cost Recovery System [MACRS]) and bonus depreciation. Bonus depreciation is ignored based on industry sources indicating that the bonus is a relatively small benefit and was not taken for many wind projects. A reasonable assumption for land-based wind projects is that 95% of the project capital cost is eligible for 5-year MACRS depreciation, and the balance of the project capital cost is eligible for 15-year MACRS. In this work, the MACRS assumption is further simplified by assuming that 100% of the wind project cost basis is eligible for 5-year MACRS.

Table 8 presents the estimated CRF and FCR in nominal and real terms using the after-tax WACC discount rate of 8.3% and 5.7%, respectively, a lifetime of 20 years, and a present value of depreciation factor of 80.5%. The nominal and real CRF are estimated at 10.4% and 8.5%, respectively. The nominal FCR is estimated at 11.8% and the real FCR is estimated 9.6%. As noted in Short, Packey, and Holt (1995), comparisons of two or more capital investments should be on a consistent tax treatment basis (i.e., both investments using a before-tax method or an after-tax method).

Table 8. 2015 Capital Recovery Factor and Fixed Charge Rate Economic Evaluation Metrics

Uniform Capital Recovery (%)		Fixed Charge Rate (%)	
Nominal	Real	Nominal	Real
10.4%	8.5%	11.8%	9.6%

[15] Carrying charges include the return on debt, return on equity, taxes, and depreciation.
[16] The fixed charge rate (FCR) does not allow for detailed analysis of specific financing structures; however, these structures can be represented through the use of a weighted-average cost of capital (WACC) as the discount rate input.

4.7 Land-Based Wind Reference Project Summary

Table 9 captures the full array of variables that reflect the land-based reference project as well as the values (for each variable) that underpin the basic LCOE inputs. The CapEx for the project is assumed to be nearly $338 million, or $1,690/kW. A contingency fund equal to 6% of CapEx, totaling $20.3 million, is used to provide a liquid financial instrument setup to respond to "known unknown" costs that arise during construction, and OpEx is estimated at $51/kW/year. A project with a 20-yr economic operating life is assumed with a nominal discount rate of 8.3%.

Table 9. Land-Based Reference Project Assumptions Summary

General Assumptions	
Project capacity (MW)	200
Number of turbines	100
Turbine capacity (MW)	2.0
Site	
Location	U.S. interior
Elevation (meters above sea level)	450
Layout	Grid
Wind speed (m/s at a 50-m height above ground)	7.25
Wind speed (m/s at a hub height 82.1-m above ground)	7.75
Net capacity factor	39.9%
Technology	
Rotor diameter (m)	102.0
Hub height (m)	82.1
Gearbox	Three stage
Generator	Asynchronous
Foundation	Spread foot
Cost (Nominal 2015 USD)	
Capital cost (millions)	$338
Contingency (6%; millions)	$20.3
OpEx ($/kW/yr)	$51
Discount rate (real)	5.7%
Discount rate (nominal)	8.3%
Economic operating life (years)	20
FCR (real)	9.6%

Note: The nominal discount rate may be generally equated with the WACC and is distinguished from the real discount rate in that it includes an inflation factor. The discount rate constitutes a principal input into the FCR, which allows for the estimation of capital recovery on an annualized basis as well as corporate income tax and depreciation.

4.8 Land-Based Wind Levelized Cost of Energy Calculation

Based on the NREL land-based baseline project inputs—CapEx, AEP, OpEx, and FCR—and using the LCOE equation, a land-based wind LCOE is computed to reflect the 2015 reference wind plant described earlier. Table 10 summarizes the costs for the primary components (including their contribution to LCOE). Data sources for this table are included in Appendix A. Figure 7 provides a graphical representation of the land-based reference project LCOE by line item.

Table 10. Land-Based Wind Reference Project LCOE Cost Breakdown

	2.0-MW Land-Based Turbine	2.0-MW Land-Based Turbine
CapEx	$1,690/kW	$46.4/MWh
OpEx	$51/kW/yr	$14.6/MWh
Net 7.25 m/s AEP at 50 m (MWh/MW/yr)	3,494	
Net capacity factor	39.6%	
FCR (real, after tax)	9.6%	
LCOE ($/MWh)	**$61**	

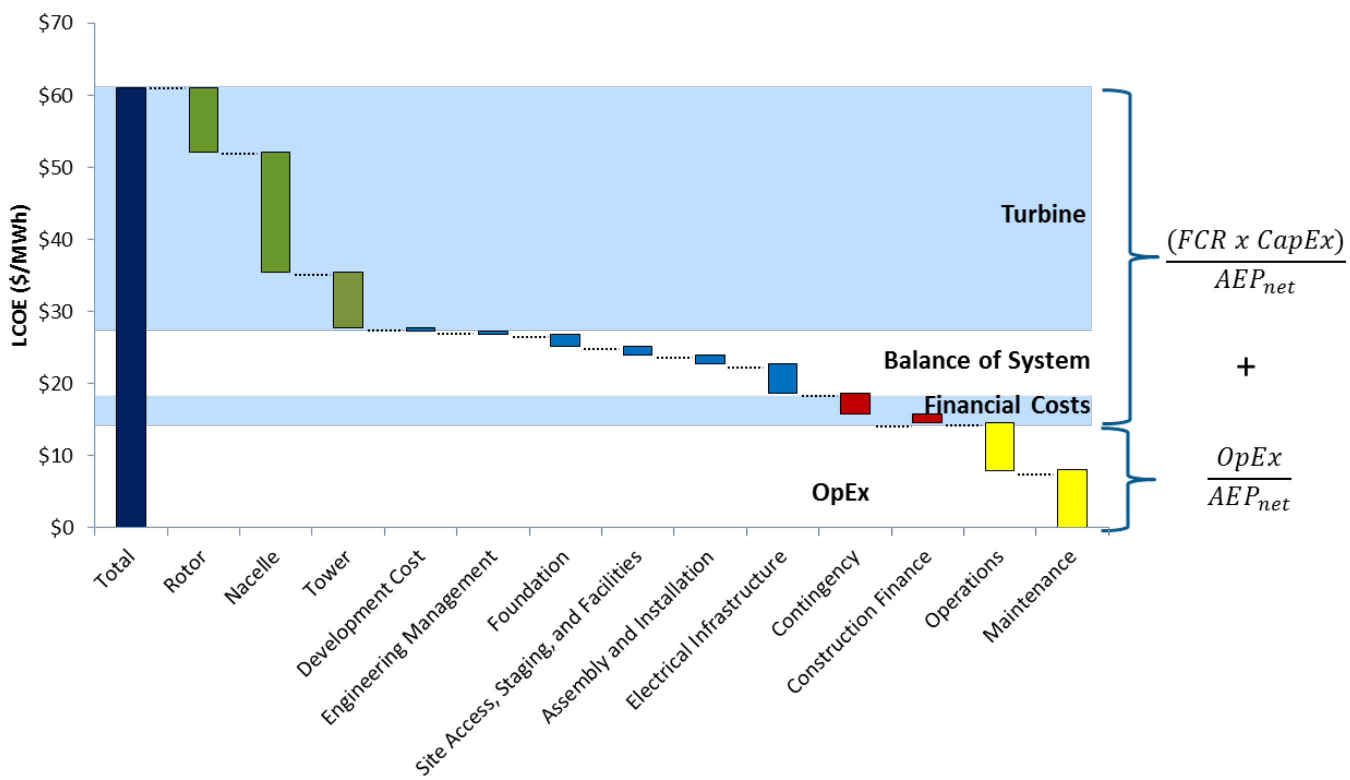


Figure 7. Component-level cost breakdown for the 2015 land-based wind reference project
Source: NREL

4.9 Land-Based Wind Levelized Cost of Energy Sensitivities

The input parameters described earlier reflect the land-based reference wind project; however, input parameters for a near-term wind project are subject to considerable uncertainty. As a result, it is beneficial to investigate how this variability may impact the LCOE. The sensitivity analysis shown in Figure 8 focuses on the basic LCOE inputs: CapEx, OpEx, capacity factor (a surrogate for AEP), and FCR, which is broken into its principal elements—discount rate and economic operational lifetime.

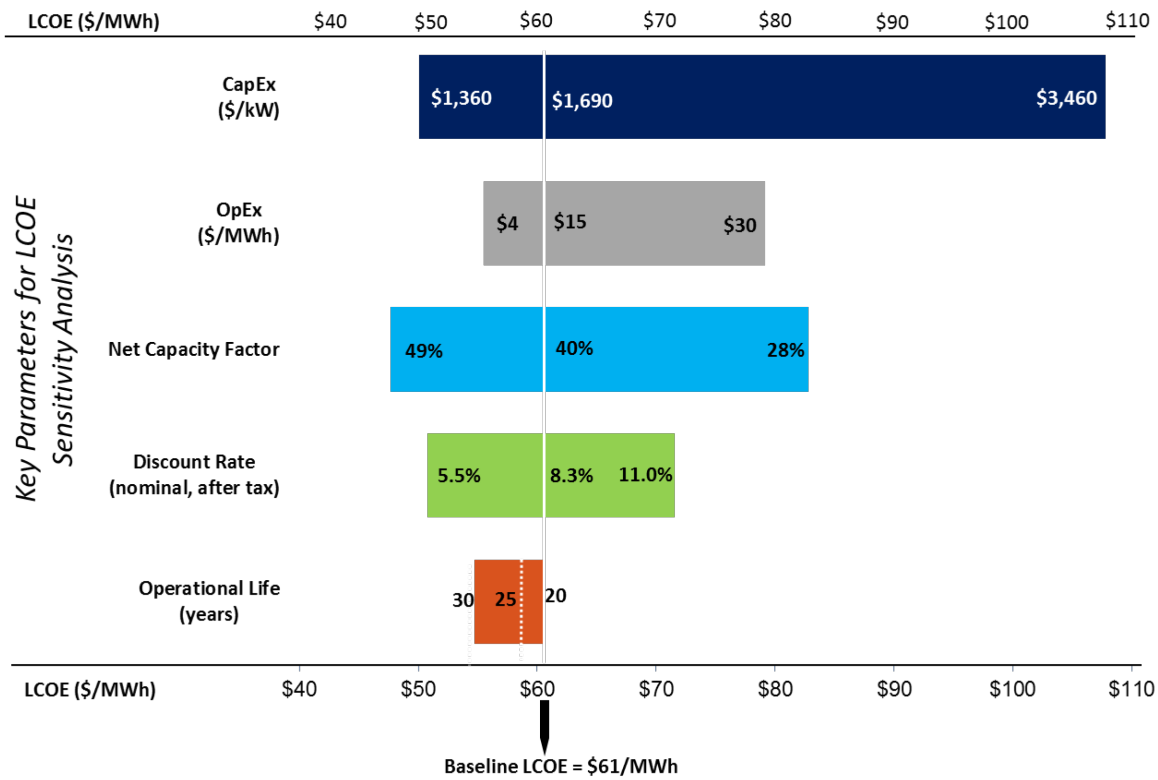


Figure 8. Sensitivity of land-based wind LCOE to key input parameters

Source: NREL

Note: The reference LCOE reflects a representative industry LCOE. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the x-axis indicate how the LCOE will change as a given variable is altered and all others are assumed constant (i.e., remain reflective of the reference project).

Sensitivity analyses were conducted by holding all reference project assumptions constant and altering only the variable in question. Sensitivity ranges were selected to represent the highs and lows observed in the industry. This selection of ranges provides insight into how real-world ranges influence LCOE. Keeping the same 200-MW project size, the sensitivity analysis yields ranges in LCOE from a low of $48/MWh to a high of $108/MWh—a low-to-high increase of over double the lower bound. Within the ranges shown, CapEx and capacity factor are the two factors that are shown to have the greatest impact on land-based wind LCOE; however, the capacity factor and discount rate appear to have the greatest influence with respect to decreasing the LCOE relative to the reference project.

As mentioned earlier, the ramp-down and termination of the PTC may lead to wind projects financed with a lower WACC or discount rate. Assuming a WACC of 7%, the reference project LCOE would be $56/MWh. As the PTC is in full effect in 2015 and 2016, it must be considered when comparing LCOE with PPAs, as discussed in the following text box.

Comparing LCOE with Power Purchase Agreement Prices

The LCOE represents the estimated cost of bringing a wind plant to commercial operation including the total investment costs, estimated annual operating costs, estimated annual energy production, and project finance costs. A PPA is a contract between a wind plant owner and an electricity purchaser. It typically specifies a set price for electricity ($/MWh) over a designated period of time. In addition to the sale of electricity, a wind plant owner can offset the cost of a wind plant by accessing other income streams such as the PTC, state incentives, or other electricity market payments.

As reported in Wiser and Bolinger (2016), the national average levelized price of wind PPAs since 2013 ranges from approximately $20/MWh to $40/MWh; this sample represents primarily wind projects located in the Interior region of the country. Wiser and Bolinger (2016) also estimate the levelized PPA price impact of the PTC at a minimum of $15/MWh (it is less than the 2015 PTC face value of $23/MWh for two reasons: 1] the PTC is available for 10 years, whereas most PPAs reflect a duration of approximately 20 years; 2] the PTC requires relatively higher cost tax equity in the project capital structure to monetize its benefits, partially eroding the effective value of the tax credit). At levels of $20/MWh and $30/MWh, PPA prices and the estimated value of the PTC suggest corresponding wind plant LCOE values of $35/MWh to $45/MWh—well below the reference project wind plant LCOE estimated in this report.

Project characteristics that could result in LCOE values in the $35/MWh–$45/MWh range are summarized in Table 11.

Table 11. Wind Plant Characteristics that Correspond to Low PPA Prices

LCOE Cost Components	Range of Values
CapEx	$1,360/kW–$1,690/kW
OpEx	$4/MWh–$15/MWh
Discount rate (assumed equivalent to WACC)	7%–8.3% (nominal, after-tax)
Annual average wind Speed at 80 m above ground level	7.75m/s–9.25 m/s
Capacity factor	40%–49%

These conditions are present in observed ranges of market data observations from 2015 illustrated in Figure 8. This analysis suggests that a combination of factors to the left of the reference project baseline are needed to achieve LCOE values that could lead to PPA prices at the levels observed since 2013 and in the $20/MWh–$30/MWh range.

Although the ranges provided here for the selected variables are grounded in actual 2015 plant costs and performance data, the high and low LCOE ranges should not be taken as absolutes. These variables are generally not independent, and it is unlikely for changes to occur only in a single variable. Moreover, each individual wind project has a unique set of characteristics, therefore, the sensitivities shown here are not universal. Section 4.10 explores regional variation in LCOE by correlating wind plant CapEx with turbine characteristics and wind resource profiles that affect capacity factor to partially address this limitation.

4.10 Regional Variation in Levelized Cost of Energy

An individual wind project will have unique costs associated with the site conditions, project investors, project ownership structure, and specific contractual mechanisms developed to purchase equipment and install all aspects of the wind plant. Although this type of project-specific data is not readily available for a large sample of installed projects, estimated LCOE values can provide useful insight into ranges and relative impacts of costs throughout the United States. In this analysis, geography impacts the cost of energy in three fundamental ways: the plant technology paired with wind resource; regional costs of labor and materials; and the distance-based cost of accessing nearby transmission lines. This section of the report illustrates estimated LCOE for over 94,000 potential wind plant locations as well as 68 locations where projects were installed in 2015. These modeled estimates provide insights into the relative LCOE for projects installed in 2015 and differences in geographic regions in the United States.

The approach used to estimate the LCOE at all potential wind plant locations in the contiguous United States is based on the *Wind Vision* (DOE 2015b) and the *2014 Cost of Wind Energy Review* (Moné et al. 2015b) using wind plant characteristics representative of 2015 wind plant market data (Wiser and Bolinger 2016). In general, wind plant characteristics in terms of rotor diameter, machine rating, hub height, and capital cost are defined to represent the range of possible wind technologies paired with wind resources that could be implemented in the United States. Power curves associated with each turbine type are used to estimate the expected annual energy capture at thousands of possible wind plant locations using long-term average hourly wind profiles. For each potential wind plant location, a cost to connect to nearby transmission infrastructure is estimated using the geographic distance between the site and the connection point. The impact of regional costs for labor and materials are represented using capital cost multipliers derived by Beamon and Leff (2013), supplemented with wind industry market data. Expected annual O&M costs and project finance costs are assumed constant for all wind plant locations to isolate the variation caused by geography. For each potential wind plant site, an LCOE is calculated using the definitions and equations in Appendix B, which are consistent with those used throughout this report and with NREL's *Annual Technology Baseline* (NREL 2016) and DOE's *Wind Vision* (DOE 2015b). This approach was also used to estimate an LCOE value for locations where a wind plant was installed in 2015. This approach complements the sensitivity analysis in Section 4.9 by providing a sense of the variation in LCOE associated with wind turbine technology/wind resource, regional variation in labor and material costs, and access to transmission infrastructure throughout the contiguous United States.

4.10.1 Site-Specific LCOE Estimates

There are three aspects of wind plant cost of energy that are affected by the geographic location of a potential wind plant in this analysis[17]: (1) the wind turbine technology and associated hourly wind speed variation over a typical year, (2) the effect of labor, materials, and other aspects that

[17] Other wind plant cost aspects that could vary with geography include balance-of-system costs associated with types of terrain and transportation costs associated with distances over which components travel to arrive at a given wind plant location. Operation and maintenance costs likely vary with wind turbine type paired with wind resource and may also be affected by regional cost impacts on labor and materials. Because of insufficient data resolution to estimate these impacts throughout the United States, these geographic influences are not represented in this study.

vary regionally across the United States, (3) the location of the wind plant relative to existing transmission infrastructure, load centers, or potential central export points. Each of these aspects influences the components of capital cost of the wind plant; the wind turbine technology paired with wind resource also affects the annual energy production.

To reflect the range of wind turbine technology that could be applied in all potential wind resource locations throughout the United States, data for the 3,760 turbines installed in 2015 were examined. As noted in Section 4.5 and in Wiser and Bolinger (2016), among wind turbines installed in 2015, the average machine rating was 2.0 MW with a rotor diameter of 102 m and corresponding specific power of 245 W/m^2. Each of the wind turbine locations for the 2015 installations was associated with a long-term, annual average wind speed at 80 m above ground level (AWS Truepower 2015); a linear fit of specific power as a function of wind speed was developed. In 2015, wind turbines were installed in a relatively narrow band of estimated annual average wind speed such that the 20th to 80th percentile wind speeds ranged from 7.4 m/s to 8.44 m/s with a median value of 8.0 m/s.[18] To estimate LCOE for all potential wind plant areas in the United States, turbine characteristics were extrapolated beyond those observed in 2015 installations to correspond to an annual average wind speed less than 5.5 m/s and greater than 10 m/s. Table 12 summarizes five wind turbine types defined to represent the entire range of locations in the United States.[19]

Table 12. Five Representative Wind Turbines Based on 2015 Wind Turbine and Annual Average Wind Speed Characteristics

	Wind Plant Characteristics Associated with Average Wind Speed				
Average Annual Wind Speed at 80-m Hub Height (m/s)	<=5.5	7.40	8.0	8.4	>=10.0
Specific Power (W/m^2)	200	237	245	255	325
Machine Rating (MW)	2	2	2	2	2
Rotor Diameter (m)	113	104	102.0	100	89
Hub Height (m)	80	80	80	80	80
CapEx ($/kW)	1,735	1,653	1,640	1,623	1,539
OpEx ($/kW/year)	51	51	51	51	51
Capacity Factor[a]	27%	39%	43%	45%	49%
FCR (Real) [Real WACC = 5.7%]	9.6%	9.6%	9.6%	9.6%	9.6%
LCOE ($/MWh)	$93	$61	$55	$53	$47

[a] Capacity factor estimated using annual average wind speed, Weibull distribution with K=2, and losses including availability of 16.7%.

These five wind turbine types result in a range of capital cost based on the rotor diameter; other parameters such as machine rating and hub height were held constant. The CapEx associated with the 50th percentile wind speed turbine type was defined to correspond to the capacity-weighted average CapEx of 2015 wind projects installed in the Interior region of the country at $1,640/kW (Wiser and Bolinger 2016). The difference in CapEx among the five wind turbine types ($208/kW for a rotor diameter range of 24 m) was derived using NREL scaling models and

[18] For comparison, the nearly 2,500 wind turbines installed in 2014 spanned wind speed ranges from the 20th to 80th percentiles of 6.78 m/s to 8.76 m/s. The 50th percentile wind speed was 8 m/s (Moné et al. 2015b).

[19] The reference project characteristics described in the prior sections are similar but not exactly reflected in this range of turbine characteristics. The primary differences are (1) the reference project is associated with a wind resource location of 7.75 m/s (at 80-m above ground level) for consistency with prior reports, which affects the capacity factor, and 2) the reference project assumes a CapEx based on the national weighted average of $1,690/kW.

compares favorably with similar estimates from MAKE Consulting (Barr et al. 2013) and Lawrence Berkeley National Laboratory (Wiser et al. 2012), each around $200/kW for similar rotor length differences.

Estimated annual energy capture, or capacity factor, is highly dependent on the hourly variation in wind speed at specific sites as well as the power curve associated with each of the five turbine types.[20] Table 12 shows the representative capacity factors for each wind turbine type assuming an annual average wind speed with a Weibull distribution. For the analysis presented in this section of the report, site-specific, long-term average hourly wind profiles from AWS Truepower were applied to the corresponding wind turbine power curve based on the annual average wind speed to estimate site-specific capacity factors. Estimated annual energy capture based on two turbine types weighted by wind speed provides a smooth transition among the five turbine types across the full range of wind resource conditions. The assumption of losses, including availability, totaled 16.7% and reflects the general effect on annual energy capture of a wind plant rather than an individual wind turbine. The analysis in this section excludes locations in which the estimated capacity factor was less than 20%.[21]

Expected annual average OpEx was assumed independent of wind turbine technology or geographic region because of insufficient data; assumptions consistent with those described in Section 4.4 were used. Similarly, project finance assumptions were held constant for all wind plant LCOE estimates to isolate geographic influences of wind turbine technology paired with wind resource, regional cost impacts, and grid connection costs (see Section 4.6.2).

The wind plant CapEx shown in Table 12 represents wind plant cost in locations with no significant logistical challenges or unusual siting conditions based on the Interior region of the United States. A study conducted by Beamon and Leff (2013) provides relative CapEx multipliers across regions of the country based on analysis of energy projects in several industries. This study captured variation in labor rates, material costs, and other aspects, and the results were interpolated between geographic regions to provide greater granularity in regional cost impacts for estimated wind plant LCOE estimates in this report and are represented graphically in Figure 9. Similar to DOE (2015), an additional capital cost increment of 20% was applied to wind plant locations in the Northeast to reflect historical market-based capital costs for land-based wind projects, which have been observed to be higher in the Northeast compared to other regions and compared to the Beamon and Leff (2013) CapEx multipliers. As illustrated in Figure 9, the Interior region has regional multipliers roughly equivalent to one and is the region used to provide a basis for wind plant cost of energy estimates. The Southeast generally has

[20] Note that the method of deriving power curves for the five representative wind turbines differed from the method used to derive a power curve for the 2015 reference turbine described in earlier sections of this report. Use of various power curves results in different estimates of annual capacity factor for comparable specific power and a hub-height wind speed of less than 2%. Future work will include assessment and harmonization of models to develop hypothetical power curves based on high-level turbine parameters such as machine rating and rotor diameter.

[21] Eliminating locations where the estimated capacity factor was less than 20% eliminated sites in which LCOE values exceeded $122/MWh; this LCOE estimate for the plant only does not include regional cost multipliers and grid connection costs. Future technology innovations yielding lower specific power and/or higher hub heights could result in lower cost projects for the same geographic location. As a result, some of the locations with very high LCOE estimates based on 2015 wind technology characteristics could achieve lower costs with technology advances.

lower costs such that the multiplier is less than one. These multipliers indicate that the same capital investment for a wind plant in the Interior region would be somewhat lower if situated in the Southeast and higher if situated in the Northeast as a result of the economic factors assessed by Beamon and Leff (2013).

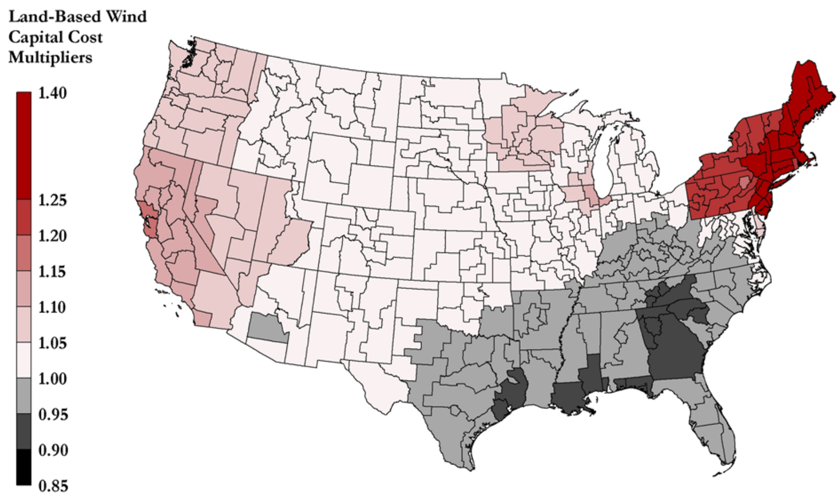


Figure 9. Land-based wind plant capital cost regional multipliers by ReEDS region based on cost multipliers implemented by DOE (2015)

The location of a wind plant relative to transmission infrastructure required to transmit power to end users affects the estimated cost of grid connection. The grid connection cost estimate is driven primarily by the geographic distance between the wind plant location and the transmission infrastructure location, but regional cost aspects such as labor rates and materials also have an impact. For this analysis, transmission infrastructure costs and regional cost multipliers are consistent with those used in DOE (2015); the equation is shown in Appendix B. For each wind plant location, the distance to a nearby grid feature is calculated. When estimating the grid connection cost for locations where projects were installed in 2015, it was assumed that the project was able to access nearby transmission lines. When estimating the grid connection cost for all potential locations where future wind plants could be installed, an optimization algorithm was used to choose between access to nearby transmission lines based on an assumption of available transmission capacity, access to nearby load centers (e.g., towns), or access to a potential central export point where power could be transmitted to adjacent regions.

Using the wind plant/wind resource characteristics, regional cost variations, and grid connection cost estimates defined earlier, LCOE was estimated for over 130,000 potential wind plant locations in the contiguous United States. Assuming a predetermined wind plant density of 3 MW/square kilometer (km^2) (Denholm et al. 2009), this corresponds to over 10,000 GW of potential wind capacity. Exclusion of locations where the estimated capacity factor was less than 20% resulted in over 94,000 locations, or over 8,000 GW of wind capacity. Similarly, LCOE was estimated for 68 locations where projects were installed in 2015.

4.10.2 Geographic Variation in Estimated Cost of Energy

Figure 10 illustrates the CapEx associated with the wind plant technology (Plant), the incremental impact of representing regional cost variation (Plant + Regional), and the incremental impact of accessing the transmission grid (Plant + Regional + Grid) for locations where projects were installed in 2015. It is important to note that these estimates are not intended to reflect actual project costs; the 2015 project estimates are based on the assumptions discussed previously and applied to all potential wind plant locations in the United States. The incremental cost associated with the regional cost variation is greatest in the Northeast. The incremental cost of accessing nearby transmission facilities is relatively small in all regions. Not surprisingly, the primary contributor to the total CapEx is the wind plant itself. The CapEx estimates for locations where projects were installed in 2015 based on the turbine parameters described in Table 12, the associated regional multiplier, and the estimated distance-based cost to access nearby transmission facilities range from $1,564/kW to $2,328/kW.

For comparison, reported average CapEx from a subset of 2014 and 2015 wind plants published in annual wind technologies market reports (Wiser and Bolinger 2015; Wiser and Bolinger 2016) is included in Figure 10.[22] In general, estimated regional CapEx follows similar trends to those observed in market data; CapEx in the Northeast and West is higher than in the Interior region, and estimates in these regions compare favorably with the market data sample. Recently, towers taller than 80 m have been installed in some regions, primarily the Great Lakes, which may partially explain the difference between estimates and market data in that region. Figure 10 illustrates one 2015 estimated CapEx compared with one actual CapEx in the Southeast preventing any conclusive assessment. Other than the Interior region, sample sizes are small both for the estimated 2015 projects as well as the reported market data for 2014 and 2015 projects. According to Wiser and Bolinger (2016), reported CapEx for projects installed in 2015, excluding identified outliers, ranged from about $1,300/kW to $2,500/kW. Much greater variability is expected in the reported capital costs because of different project sizes, turbine sizes, and the relationship between turbine type and wind resource, among other things, than indicated by the capacity-weighted averages shown in Figure 10. The geography-based estimates developed here produce a range of CapEx similar to that observed in market data.

[22] The market data sample includes 56 projects in the Interior region (8,260 MW), 7 projects in the West (422 MW), 6 projects in the Northeast (252 MW), 10 projects in the Great Lakes (687 MW), and 1 project in the Southeast (40 MW) (Wiser and Bolinger 2015, 2016).

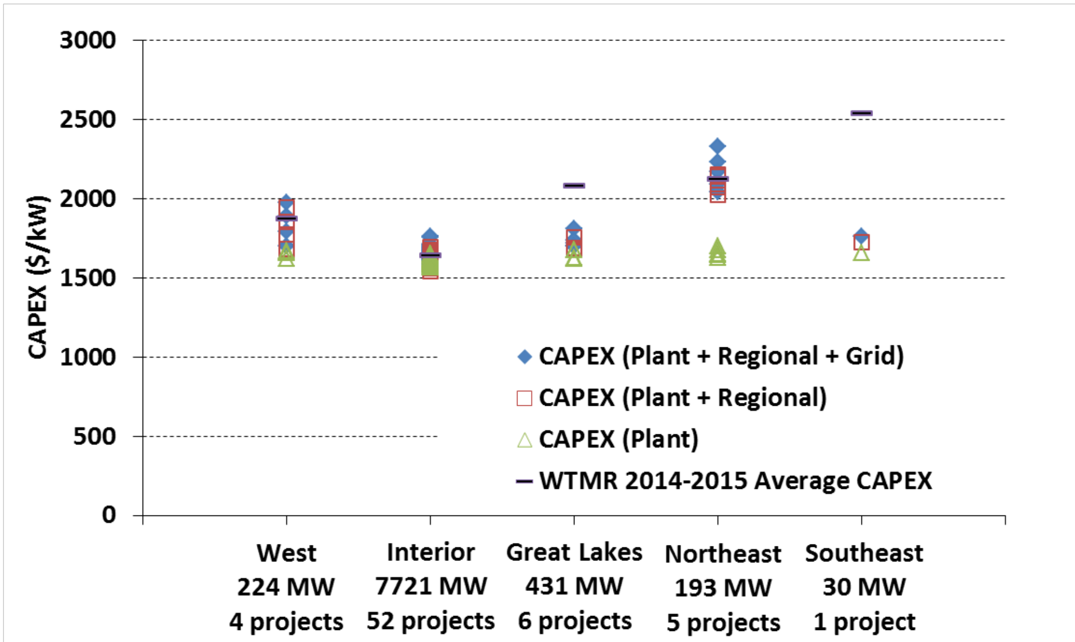


Figure 10. CapEx estimated for locations where projects were installed in 2015 including the wind plant, regional cost increment, and grid connection cost increment

(wind technologies market report [WTMR])

Figure 11 illustrates the cost of energy range nationally and for five regions. LCOE is estimated for over 94,000 potential wind plant locations, or about 8,000 GW of wind plant capacity in the contiguous United States. The observed range extends from $39/MWh to $241/MWh with a capacity-weighted average of $83/MWh. For comparison, estimated LCOE associated with locations where projects were built in 2015 range from $50/MWh to $111/MWh with a capacity-weighted average of $57/MWh.[23]

The majority of the 68 projects installed in 2015 are associated with the Interior region of the country (52 projects). In general, projects installed in 2015 correspond to lower-cost locations within each region. Substantial low-cost resources remain available in all regions. There are about 897.5 GW of potential wind plant capacity estimated at less than $60/MWh nationally. This capacity is distributed across regions with 1.7 GW in the West, 894.9 GW in the Interior, 0.4 GW in the Great Lakes, 0.1 GW in the Northeast, and 0.3 GW in the Southeast.

[23] Estimated LCOE for projects installed in 2014 ranged from $52/MWh to $178/MWh with a capacity-weighted average of $65/MWh (Moné et al. 2015b). These projects spanned a greater range of resource potential than those installed in 2015.

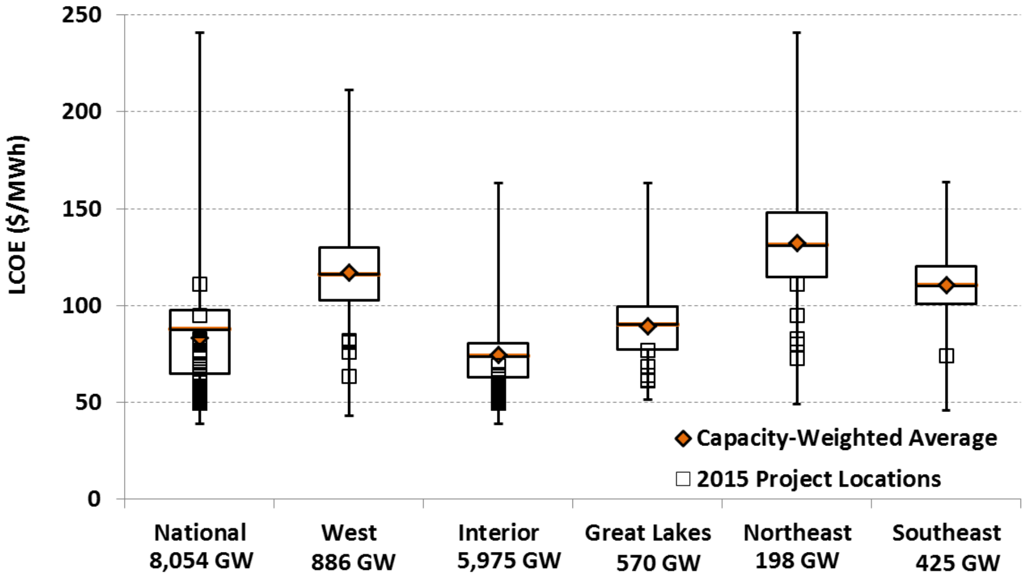


Figure 11. Estimated cost of energy for potential wind plants in the contiguous United States. The graphic illustrates the median (horizontal line), capacity-weighted average (gold diamond), 25th–75th percentile (box), and minimum and maximum (lines with end caps). The estimated LCOE for locations where projects were installed in 2015 are identified (black squares).

Figure 12 illustrates the capacity-weighted average LCOE nationally and by region with each of the three geographic aspects represented. For each region, there are three LCOE estimates: (1) average LCOE for 100% of potential wind resource locations in the region, (2) average LCOE for 3.5% of the lowest-cost wind resource locations in the region, and (3) estimated average LCOE for locations where projects were installed in 2015. The 100% wind resource potential represents over 8,000 GW of potential wind plant capacity, whereas the 3.5% resource potential sample represents about 280 GW—an amount similar to that represented in the *Wind Vision* scenario (DOE 2015b) in 2050 (although the regional characteristics of that scenario differ from the capacity shown in this figure). The 2015 projects represent 8 GW of installed capacity, primarily in the Interior region.

Figure 12 illustrates, on average, the relative contribution of the wind turbine/wind resource pairing, the regional cost impacts, and the grid connection cost to LCOE. The average LCOE associated with the 100% resource potential sites is higher than the average LCOE for the 3.5% lowest-cost sites within that region, primarily because of the inclusion of many lower quality but still viable wind resource conditions (the proportion associated with the plant). The grid-connection cost portion of LCOE is larger in the 100% resource potential than in either the 3.5% resource potential or 2015 project groups. This observation reflects the assumption that as existing transmission line capacity is filled with more optimal wind plant sites, the cost increases as the distance required to transmit the power increases.[24] The 3.5% resource potential group, representing about 280 GW of capacity, illustrates that the grid connection cost portion of the LCOE is relatively small, and generally similar to that associated with estimated LCOE for

[24] It is important to note that the grid connection costs escalate as assumed capacity available on existing transmission lines is filled such that for the higher cost resources the grid connection costs likely include estimates based on long distances. Investment in long transmission lines is not likely to be incurred on a wind-plant-by-wind-plant basis in future decades, but this approach provides an assessment of cost of energy impacts related to grid access based on current, approximate estimates of available transmission capacity.

plants installed in 2015. The regional cost contribution is similar in all three LCOE estimates for each region. The estimated average LCOE for 2015 projects is impacted by regional costs and grid connection costs similar to the 280 GW represented in the 3.5% resource potential sites. In other words, there are locations within each region totaling about 280 GW of wind plant capacity that will have similar wind plant characteristics, regional cost impacts, and grid connection costs to those estimated for locations where projects were installed in 2015. This subset of the total resource potential available is more likely to be utilized in the future than the higher cost options that remain.

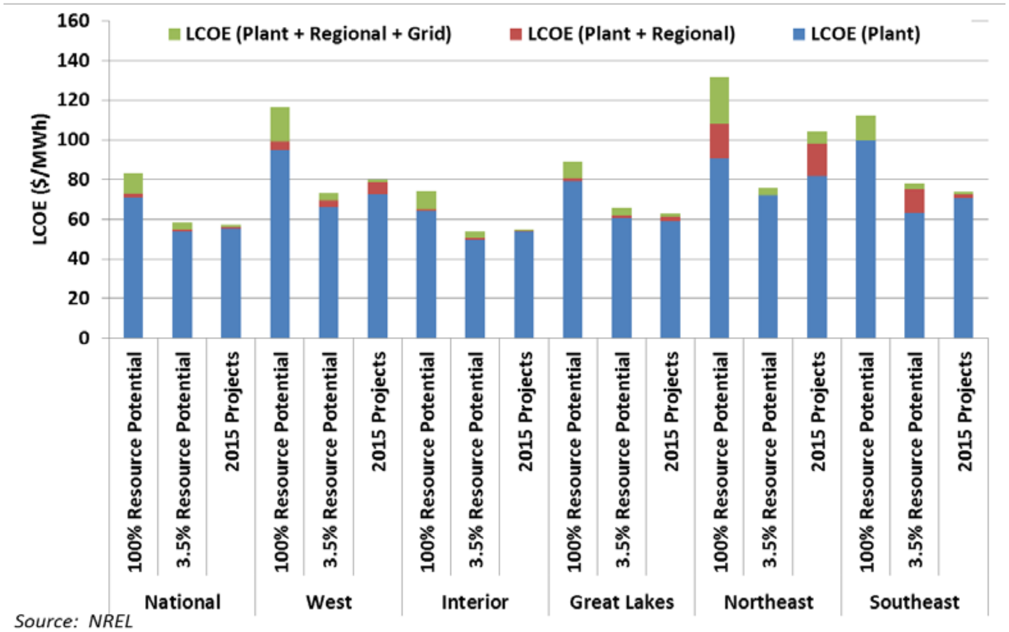


Figure 12. Capacity-weighted average LCOE nationally and by region for 8,000-GW potential wind plant capacity (100% Resource Potential), capacity representing 280 GW (3.5% Resource Potential), and wind projects installed in 2015 (2015 Projects)

As noted earlier, significant wind resource potential exists in each region of the United States. Figure 13 illustrates the distribution of that capacity by estimated LCOE in each region and nationally. The figure also illustrates the shift of capacity into higher-cost bins associated with the three different aspects of geography explored earlier. As costs increase with each additional aspect, the capacity available at a given LCOE range shifts to the right.

Focusing on the $50–$60/MWh bin in each of the regional histograms shows how these incremental costs affect the available resource. In the West, 5.9 GW of potential capacity is estimated to cost $50–$60/MWh when considering the wind turbine technology associated with the site-specific wind resource (Plant). This capacity is reduced to 2.7 GW after regional labor and material costs are applied (Plant + Regional), and it is further reduced to 1.7 GW when the estimated cost of building transmission lines to connect to nearby access points are included (Plant + Regional + Grid). Similarly, in the Great Lakes, when each aspect of geographic cost influence is considered the available resource is reduced substantially, from 14.3 GW to 0.4 GW. In the Northeast, relatively low-cost wind plants are impacted by both the high regional costs and grid access such that less than 0.1 GW of 2.5 GW remains in the $50–$60/MWh bin. In the Southeast, both regional costs and grid connection costs are low with half of the available resource potential remaining (0.3 GW of 0.6 GW available). Although the capacity in the Interior region in the $50–$60/MWh bin after geographic influences are applied (891.0 GW) is significantly lower than the capacity based on the wind plant alone (2,790.3 GW), it remains vast in comparison to other regions.

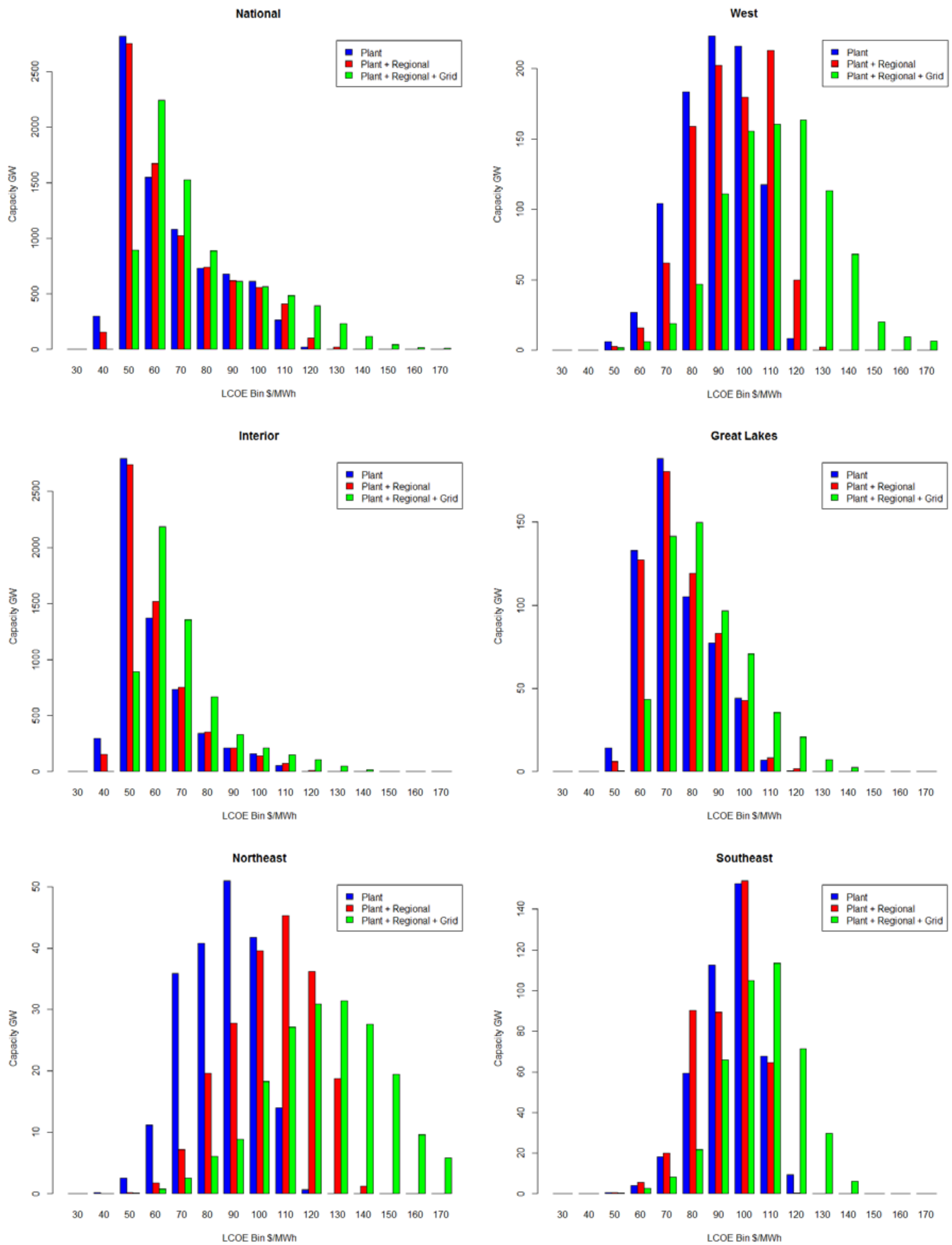


Figure 13. Histogram of wind plant potential capacity for LCOE ranging from $39/MWh to $180/MWh (graphics truncated for visualization). Note that the LCOE bin labels include the lower bound of the histogram bin, and the y-axis varies in each histogram.

This analysis of geographic influence on LCOE complements the sensitivity analysis presented in Section 4.9. Rather than varying the project parameters, CapEx, and capacity factor independently, as in Section 4.9, these parameters were correlated with wind turbine technology paired with wind resource conditions throughout the United States. The resulting range in LCOE estimates for projects installed in 2015— $50/MWh to $111/MWh—is similar to that resulting from the independent factor sensitivity analysis of observed 2015 market conditions: $48/MWh to $108/MWh. The weighted average of the estimated 2015 LCOE based on geography is lower, at $57/MWh, than the reference project LCOE of $61/MWh. Additional factors such as project life, discount rate, and OpEx could affect the LCOE ranges for geographically dependent LCOE in the same way as the independent variable sensitivity analysis. Notably this analysis also relies on mesoscale wind resource data, which may or may not be robust for the locations where projects are installed and operating. Potential discrepancies in wind resource for individual plants as well as actual project-level variability in assumed project life, discount rate, and OpEx as noted above may partially account for the calculated difference in 2015 weighted average LCOE and observed market PPA prices (see also the prior text box on this topic).

Combined-cycle natural gas plants are the type of technology that frequently competes against new wind plant investments. Lazard (2016) and BNEF (2016b) have estimated LCOE for new combined-cycle gas turbine plants in the United States at $48/MWh to $78/MWh and $76/MWh to $82/MWh, respectively. In each case, different assumptions are used to reflect the range of CapEx, OpEx, capacity factor, and project finance, so comparison with the wind LCOE estimates in this report cannot be made directly. The wind LCOE estimates illustrate, however, that there are locations in the United States that are within or below these combined-cycle gas turbine estimates, particularly in the Interior region of the country. As noted in Section 4.9, the availability of the PTC offsets a portion of the LCOE and is estimated to have a minimum value of approximately $15/MWh in LCOE terms, allowing many potential wind plants to be even more competitive with new natural gas plant investments.

5 Offshore Wind

The first offshore wind project in the United States—Block Island Wind Farm—began construction in April 2015 and began operation in the fall of 2016. Although this is a new beginning for the nation, the lack of domestic experience with offshore wind technology introduces considerable uncertainty into cost estimates for potential domestic offshore wind projects. A recently released report, *2016 Offshore Wind Energy Resource Assessment for the United States* (Musial et al. 2016), estimates that the net technical resource capacity of domestic offshore wind resource is 7,203 terawatt-hours/yr (2,058 GW), which would be approximately twice as large as the current electricity demand of the United States (Energy Information Administration [EIA] 2015).

This section explains the methodology and assumptions of calculating LCOE for U.S. offshore wind with each subsection detailing the data at the offshore reference project site. Section 5.2 specifically details the changes from previous Cost of Wind Energy Review publications that affect this analysis. All data comes from NREL's OWDB, which is populated by global market data and used to analyze market trends of offshore wind costs in Europe, to determine cost projections for the United States, and to inform internal NREL modeling. The analysis updates previous offshore market research such as the *2014–2015 Offshore Wind Technologies Market Report* (Smith, Stehly, and Musial 2015) as well as the reported costs of domestic offshore wind energy reported in the *2014 Cost of Wind Energy Review* (Moné et al. 2015). The reference project site is located in the North Atlantic Ocean at a distance of 30 km from the U.S. mainland. This hypothetical reference site differs from the prior reference but is considered representative of the locations of the first offshore wind projects in the United States. Although it reflects a change from prior cost of energy reviews, the distance from shore applied in this report is consistent with that used to estimate LCOE in analysis conducted for the *National Offshore Wind Strategy: Facilitating the Development of the Offshore Wind Industry in the United States* (Gilman et al. 2016) and *A Spatial-Economic Cost-Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030* (Beiter et al. 2016).

Table 13 and Table 14 summarize major inputs and LCOE analysis results for a fixed-bottom and floating offshore reference project, which are described in more detail in the following sections.

Table 13. Summary of Inputs and Results for the Fixed-Bottom Offshore Wind Project

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
Turbine capital cost	1,466	41.8
Balance of system	2,167	61.9
Financial costs	983	28.0
Capital expenditures (CapEx)	**4,615**	**131.7**
Operational expenditures (OpEx; $/kW/yr)	179	49.6
Fixed charge rate (%)	10.3	
Net annual energy production (MWh/MW/yr)	3,608	
Net capacity factor (%)	41.2	
TOTAL LCOE ($/MWh)	**181**	

[a] Sources are listed in the relevant sections of this report related to the specific cost components.
Note: Reported costs are in 2015 U.S. dollars using U.S. Consumer Price Index data (Bureau of Labor Statistics 2016).

Table 14. Summary of Inputs and Results for the Floating Offshore Wind Project

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
Turbine capital cost	1,466	42.0
Balance of system	4,146	118.6
Financial costs	1,035	29.6
Capital expenditures (CapEx)	**6,647**	**190.4**
Operational expenditures (OpEx; $/kW/yr)	138	38.4
Fixed charge rate (%)	10.3	
Net annual energy production (MWh/MW/yr)	3,595	
Net capacity factor (%)	41.0	
TOTAL LCOE ($/MWh)	**229**	

[a] Sources are listed in the relevant sections of this report related to the specific cost components.
Note: Reported costs are in 2015 U.S. dollars using U.S. Consumer Price Index data (Bureau of Labor Statistics 2016).

5.1 Market Developments in 2015

The cumulative global offshore wind market reached over 12 GW by the end of 2015 with new capacity totaling nearly 3.4 GW (Global Wind Energy Council [GWEC] 2016). To date, offshore wind development has been highly concentrated geographically, with over 91% of cumulative capacity commissioned in Europe. Specifically, over 40% of global capacity is located in the United Kingdom and 27% in Germany. Commissioned projects in Asia are starting to accelerate, with 654 MW commissioned in China and 52 MW in Japan (GWEC 2016). Analysis of the global market suggests that international wind companies are poised for growth with aggressive goals in both Europe and Asia; however, deployments have been affected by uncertainty in the form, and value of, incentives (United Kingdom), delays in grid development (Germany), and local and national government concerns (China). In the United States, the four principal hurdles are:

- **The lack of a stable market for offshore wind power**. The biggest near-term challenge for the offshore wind energy industry is the lack of a stable market. Federal incentives are generally not sufficient to attract investment in offshore wind projects by themselves given the current cost structure, and there is significant ambiguity about the continued availability of these incentives. Developers are therefore working with the state representatives to augment the federal incentives and achieve financial viability, either through offshore wind-specific revenue streams (Offshore Renewable Energy Credits) or by negotiating long-term PPAs. Although this approach is allowing a number of projects to move forward, it is complicated and resource-intensive for developers.
- **An uncertain timeline for permitting**. The Bureau of Ocean Energy Management (BOEM) (2011) has made considerable progress in leasing and permitting projects since the "Smart from the Start" initiative was announced in 2010. BOEM has awarded commercial leases in 11 wind energy areas and is moving forward with additional auctions in the planning stages. Despite this progress, the total timeline for permitting remains to be seen (DOE 2016).
- **Lack of a domestic supply chain.** The various cost reduction pathway reports (EC Harris 2012; The Crown Estate 2012) conclude that to lower the cost of offshore energy a strong domestic supply chain, vessels, and infrastructure will be required. *The Cost Reduction Monitoring Framework 2015* report (Catapult 2015) found that the lack of visibility of market deployment in the United Kingdom was the largest risk to achieving their 2020 LCOE estimate. In the *U.S. Wind Energy Manufacturing and Supply Chain: A Competitiveness Analysis* (Fullenkamp and Holody 2014), it was determined that investment in facilities and equipment across the offshore supply chain would be required. This investment could be either upgrading facilities or relocating facilities port side to simplify transportation and encourage cost competitiveness.
- **Investor confidence in offshore wind to lower risk reduction**. There are numerous risks associated with offshore wind that affect the cost of energy. Offshore wind projects are capital-intensive endeavors and a change in the CapEx could have a significant effect on LCOE. As the offshore industry grows and gains experience, some of the key risks (e.g., installation cost and timing, turbine availability, and OpEx) are expected to be more manageable and the overall risk profile of offshore wind plant projects will likely decrease. In addition, the reduction in uncertainty around the preconstruction energy estimate has direct financial implications (Clifton, Smith, and Fields 2016). As the apparent risks decrease in either CapEx or energy production, so may the required returns demanded by financiers.

However, there are also a number of positive recent developments that suggest that the market activity is accelerating, such as:

- Since 2012, DOE has been working on advancing the U.S. offshore wind market by supporting a portfolio of demonstration projects. In May 2016, DOE identified three projects from its offshore wind portfolio that were eligible for up to $40 million each in funding to build their projects— Fisherman's Energy Atlantic City Windfarm, Lake Erie Energy Development Corporation's Icebreaker project, and the University of Maine's New England Aqua Ventus I project (DOE 2015a).
- To date, BOEM has conducted six auctions for wind energy areas in federal waters located off the coast of Delaware, Massachusetts, Virginia, and New Jersey. In addition, BOEM is in the planning stages for a wind energy area offshore New York, North Carolina, South Carolina, Oregon, and Hawaii (BOEM undated).
- In August 2016, the Massachusetts legislature passed an energy bill that requires the state to purchase 1,600 MW of offshore wind power in addition to 1,200 MW of other renewable resources such as hydropower, solar, or land-based wind. The passage of the energy bill creates a path for the two offshore wind energy areas, owned by DONG Energy and Offshore MW, LLC in Massachusetts, and two in Rhode Island owned by Deepwater Wind, to develop the projects and possibly accelerate the deployment of U.S. offshore projects.[25]
- The New York State Energy Research and Development Authority (2016) stated it will participate in the BOEM auction for a commercial offshore wind energy lease off the coast of Long Island, New York. The New York Public Service Commission has approved a statewide clean energy program to ensure that 50% of the state's energy comes from renewable and clean energy resources by 2030. In addition, Governor Cuomo announced the creation of an Offshore Wind Master Plan in his 2016 State of the State address (New York State Energy Research and Development Authority 2016).
- DONG Energy, a Danish company that has built more offshore wind farms than any other company worldwide, agreed to take over two of four separate 1,000-MW offshore wind development areas located off the coast of Massachusetts and New Jersey. DONG Energy's entrance into the U.S. offshore wind market, the first offshore projects that the company is involved in that are located outside of Europe, brings experience and expertise in building an offshore project and confirmation of the potential for the United States to become a significant location for future development.

5.2 Changes in Offshore Wind LCOE Calculations

A sizable, ongoing effort has been made over the past several years to create a new offshore wind strategy as well as new baseline costs and LCOE goals. Changes in methodology and project site assumptions have taken place over the past year as part of this process and this section highlights the major changes from past cost of wind energy review reports. However, more detail than what is described in this section can be found in both the *National Offshore*

[25] Massachusetts Bill H4568 states that the project must "operate in a designated wind energy area for which an initial federal lease was issued on a competitive basis after January 1, 2012." This language currently excludes Cape Wind from the possible projects because its current lease was signed in 2010.

Wind Strategy (Gilman et al. 2016) and *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016). A number of these assumptions being used to represent a U.S. cost of energy assume a mature supply chain, locations that align with current BOEM lease areas, and constant EURO-USD exchange rates.

The first major change was the project size. Previous analysis used a 500-MW project size, which, given the change in turbine size, would change the total number of turbines, thereby affecting the BOS and O&M calculations. The offshore strategy and cost reduction pathway reports used a 600-MW project size. The initial geographic information system analysis conducted by NREL segmented the U.S. offshore area into 7,159 distinct wind plant layouts of 600 MW each to calculate energy production around the country. This size was chosen because of the extensive data the OWDB has on 6-MW offshore turbines; it also allowed for a symmetrical 10-by-10 grid of turbines within each project for analysis.

The second change is the application of the Jones-Act-compliance adder. The Jones Act stipulates that only U.S.-flagged vessels may make trips between two U.S. ports. As a result, a cost factor is needed that accounts for the additional cost foreseen from using only U.S.-flagged vessels that have substantially lower installation capabilities compared to the purpose-built fleet of European turbine installation vessels. For 2015, the costs associated with assembly and installation and O&M include a 23% adder. As the U.S. offshore wind industry matures, we expect that there will be an increase in Jones-Act-compliant vessels and this adder will no longer need to be factored into the analysis.

The third change is the location of the offshore reference project site. Previously, the fixed-bottom site used a distance from shore of 20 km and a water depth of 15 m. Currently, BOEM lease areas in the North Atlantic, where the first projects are expected to be installed, have an average distance from shore of 30 km and a water depth of 30 m. These values affect the BOS and O&M calculations because of the need to move materials required for foundations, the distance from the port for assembly and maintenance, and longer electrical cabling. Additional details describing the changes in methodology and comparisons to the various reports released since the *2014 Cost of Wind Energy Review* can be found in Appendix C.

5.3 Capital Expenditures for Offshore Wind Reference Projects

The various components of the offshore project CapEx for both fixed-bottom and floating substructures was influenced by utilizing NREL's OWDB, which contains information on 14 offshore wind projects installed in 2015 corresponding to 3,831 MW of capacity. The data were obtained by conducting several parallel assessments: analyzing global market data, reviewing published literature, cost component and reduction reports, recent press statements, and collaborating with industry.

The average turbine installed globally in 2015 was 4.14 MW with a 118.9-m rotor diameter, almost 25% larger than installed in 2014. Given the lack of U.S. offshore projects, the CapEx was modeled based on a combination of empirical data and scaling relationships (for example, using the NREL 2015 CSM or the Offshore Balance of System model); greater detail can be found in Beiter et al. (2016) and Maness et al. (2016). The various NREL models yielded a CapEx of $4,615/kW for fixed-bottom substructures. For floating substructures, the empirical models and studies that have been conducted assume a relatively stable supply chain for commercial-scale projects, although only demonstration projects with one or two turbines have been realized to date. These studies derived a floating CapEx of $6,875/kW.

When reviewing the results it should be noted that all costs were converted to U.S. dollars (USD) from the original reported year exchange rate and inflated to 2015 USD using the Consumer Price Index. A breakdown of the CapEx for the fixed-bottom offshore reference project is shown in Figure 14. The shades of green represent the turbine cost, shades of blue represent BOS costs, and shades of purple represent financial costs. The dollar-value component cost breakdown is shown in Table 15. Figure 15 and Table 16 describe the same breakdown for the floating offshore reference project.

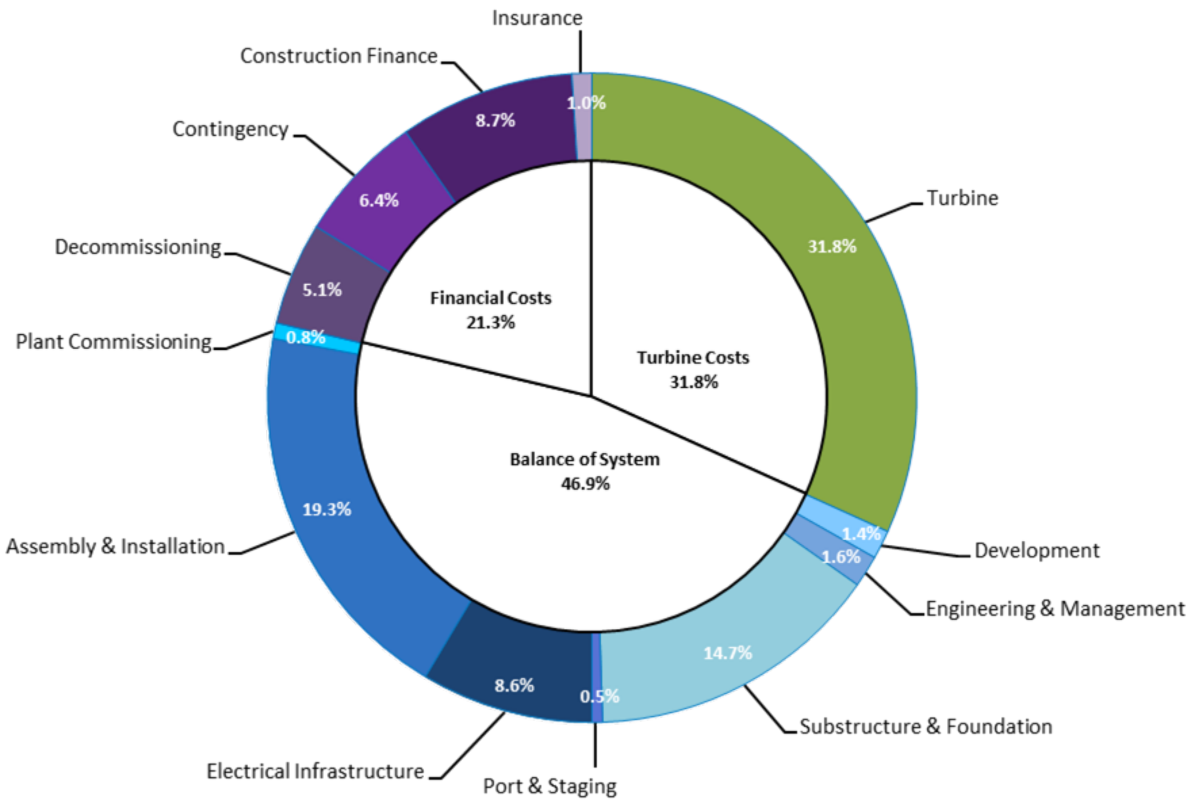


Figure 14. Capital expenditures for the 2015 fixed-bottom offshore wind reference project
Source: NREL

Table 15. Fixed-Bottom Offshore LCOE Component Cost Breakdown

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
TURBINE CAPITAL COST	**1,466**	**41.4**
Development cost	66	1.9
Engineering management	73	2.1
Substructure and foundation	679	19.4
Site access, staging, and port	24	0.7
Electrical infrastructure	396	11.3
Assembly and installation	893	25.5
Plant commissioning	36	1.0
BALANCE OF SYSTEM	**2,167**	**61.9**
Insurance	46	1.3
Decommissioning (surety bond)	237	6.8
Construction financing cost	297	8.5
Contingency	403	11.5
FINANCIAL COSTS	**983**	**28.1**
TOTAL CAPITAL EXPENDITURES	**4,615**	**131.7**

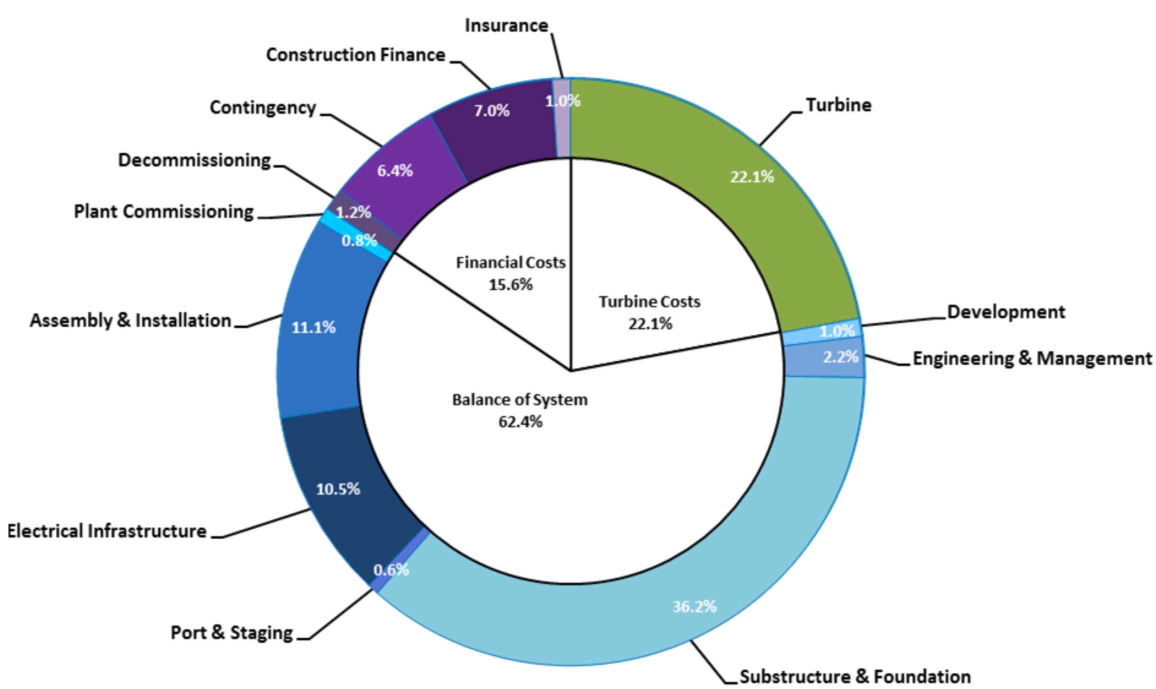


Figure 15. Capital expenditures for the 2015 floating offshore wind reference project
Source: NREL

Table 16. Floating Offshore LCOE Component Cost Breakdown

	4.14-MW Offshore Turbine ($/kW)	4.14-MW Offshore Turbine ($/MWh)
TURBINE CAPITAL COST	**1,466**	**42.0**
Development cost	66	1.9
Engineering management	149	4.3
Substructure and foundation	2,404	68.9
Site access, staging, and port	40	1.1
Electrical infrastructure	695	19.9
Assembly and installation	736	21.1
Plant commissioning	56	1.6
BALANCE OF SYSTEM	**4,615**	**118.8**
Insurance	66	1.9
Decommissioning (surety bond)	80	2.3
Construction financing cost	427	12.2
Contingency	462	13.2
FINANCIAL COSTS	**1,035**	**29.6**
TOTAL CAPITAL EXPENDITURES	**6,647**	**190.4**

There is a notable difference between the cost components that make up the land-based and offshore projects. In the land-based project, 72% of the cost is related to the turbine. For the offshore project, the turbine makes up 32% of the fixed-bottom offshore and 22% of the floating offshore reference project costs. The substructure and foundation portion of the BOS costs is the primary cause for the cost differences between the fixed-bottom and floating offshore project because of the dramatic increase in steel required for the floating substructure compared to a traditional fixed bottom. The other differences in the BOS and financial costs are related to the empirical-based scaling relationships that are also based on total costs.

5.4 Operational Expenditures for Offshore Wind

OpEx can vary greatly between projects for a number of reasons but the two largest cost drivers are the distance from the project to the maintenance facilities and the meteorological ocean climate at the site (Maples et al. 2013; Jacquemin et al. 2011; Pieterman 2011). Beiter et al. (2016) evaluated the OpEx for fixed-bottom and floating substructures located at sites with various wave heights, water depths, and distances from ports using the Energy Research Centre of the Netherlands (ECN) O&M Tool.[26] The Outer Continental Shelf lease payment, which is estimated to be 12% of the operating cost, was included in the results from the O&M Tool as a

[26] Operation and maintenance costs for offshore wind projects are assumed to include labor, vessels, equipment, scheduled maintenance, unscheduled maintenance, land-based support, and administration.

fixed operating cost.[27] Table 17 summarizes the costs for either fixed-bottom or floating substructures at the reference project site in the North Atlantic. In addition, the Jones Act adder of 23% discussed in Section 5.2 was included in the O&M Tool results by increasing the costs of all vessels.

Table 17. Offshore OpEx Costs for Reference Site

	Fixed-Bottom Substructure	Floating Substructure
Operating cost ($/kW)	31	31
Maintenance cost ($/kW)	148	107
OPERATIONAL EXPENDITURES ($/kW/yr)	**179**	**138**

5.5 Offshore Annual Energy Production and Capacity Factor

Smith, Stehly, and Musial (2015) reported that installed European offshore wind projects typically achieve capacity factors between 35% and 52%. In general, capacity factors have been improving for two reasons. First, siting decisions for initial projects emphasized locations that were close to shore and relatively sheltered so that developers could gain experience before moving into open-ocean conditions. Offshore wind development zones are now increasingly located farther from shore to allow for larger projects and enable access to a more energetic and consistent wind resource. Second, offshore wind turbine technology has improved over the last decade; larger rotor-to-generator ratios increase the amount of energy that can be captured in a given wind resource.

Because AEP_{net} and the corresponding net capacity factor will vary with the wind resource and project design, we assumed specific site characteristics that are common to the North Atlantic Coast for the reference offshore wind project. AEP_{net} was calculated using commercially available technology and NREL CSM (Fingersh, Hand, and Laxson 2006; Maples, Hand, and Musial 2010) with typical wind resources of the North Atlantic (Beiter et al. 2016). Turbine characteristics, such as turbine rated power, rotor diameter, and hub height were assumed from the average values of the global offshore wind projects installed in 2015. Table 18 shows the assumptions used to calculate the AEP_{net} for both the fixed-bottom and floating reference projects.

[27] Lease payments are expected to range between 2% and 7% of operational revenue. An Atlantic project will pay 2% of operational revenue in years 1 to 15. The lease payment increases to 7% of operational revenue from year 16 until the plant is decommissioned (BOEM 2011).

Table 18. AEP Input Assumptions for Offshore Reference Site

Turbine Parameters		
Turbine rated power (MW)	4.14	
Turbine rotor diameter (m)	118.9	
Turbine hub height (m)	90.3	
Maximum rotor tip speed (m/s)	90	
Tip-speed ratio at peak coefficient of power (C_p)	8	
Drivetrain design	Geared	
Rotor peak power coefficient C_p	0.47	
Wind Resource Characteristics		
Annual average wind speed at 50 m (m/s)	8.4	
Annual average wind speed at 90.3 m (m/s)	8.9	
Weibull K	2.1	
Shear exponent	0.1	
Losses		
Losses	Fixed	Floating
Environmental (icing, blade soiling, lightning)	1.59%	1.59%
Technical (hysteresis, parasitic)	1.20%	1.20%
Wake loss (site-specific loss)	5.14%	5.14%
Total electrical loss (site-specific loss)	3.30%	3.36%
Availability loss (site-specific loss)	6.34%	6.42%
TOTAL LOSSES	**16.30%**	**16.59%**

Like any offshore wind plants, the U.S. offshore reference project will experience losses from array wake impacts, availability, and inefficiencies in power collection and transmission. Previous cost of wind energy review reports have estimated the losses as a total of 15% to account for environmental losses, electrical losses, technical losses, and wakes. Beiter et al. (2016) estimated an empirical relationship for site-specific losses such as wakes, electrical, and availability, which have been incorporated into this analysis to calculate AEP_{net}. Table 19 shows the impact of losses on AEP_{net} and capacity factor.

Table 19. Summary of Offshore Wind Turbine AEP and Capacity Factor

	Fixed Bottom	Floating
Gross AEP (MWh/MW/yr)	4,309	4,309
Gross capacity factor (%)	49.2	49.2
Losses and availability (%)	16.30	16.59
AEP_{net} (MWh/MW/yr)	3,608	3,595
Net capacity factor (%)	**41.2**	**41.0**

The 2015 fixed-bottom baseline project is calculated to deliver 3,608 MWh/MW/yr annually, which is equivalent to a net capacity factor of 41.2%, whereas the floating baseline project delivers 3,595 MWh/MW/yr or a 41.0% net capacity factor. The difference is a result of the increased electrical losses in the floating offshore system using dynamic cabling. This net capacity factor is representative for this size of turbine with some generic losses. However, larger rotors are being installed currently that would raise the net capacity factor to over 45%.

5.6 Financial Parameters for Offshore Wind

Although the United States is a global leader in cumulative installed wind energy capacity, the first domestic commercial offshore wind project only became operational recently. After successfully securing financing in March 2015, the 30-MW Block Island Wind Farm began operation in late 2016. Investors and lenders recognize the risks in capital-intensive offshore wind projects, particularly in the U.S. offshore wind sector (Remec et al. 2013). One prominent example of offshore wind development is Cape Wind, which began development in 2001 but has faced obstacles for many years. In January 2015, the utilities slated to purchase power from Cape Wind terminated their PPAs because of an inability to meet a key milestone to obtain full project financing and start construction, or alternatively, to post financial collateral to extend the agreements (O'Sullivan 2015). Future U.S. projects are anticipated to benefit from European experience until a sufficient quantity of U.S. projects are fully financed and operating, which should also provide clarity about the risks in the domestic offshore wind business.

5.6.1 Overview of European Trends in Offshore Wind Finance

Nearly 14 GW of total wind power capacity (3.4 GW of offshore) was commissioned in the European Union during 2015, bringing the total offshore wind installed capacity to over 12 GW (European Wind Energy Association [EWEA] 2015a). Historically, power producers in Europe have used their balance sheets to finance offshore wind projects, but with increasing demand for capital, other investors are entering the market, including wind turbine manufacturers, corporate investors, oil and gas companies, and engineering, procurement, and construction companies (EWEA 2013). Analysts expect compounded annual growth in the European offshore wind market to exceed 20% from 2014 through 2020. Currently, 8.9 GW of European offshore projects require financing of 35.7 billion euros, less than the 54.5 billion euros that was invested during the last 5 years.

BNEF's list of completed offshore wind financial transactions from January 2012 through May 2015 includes 96 projects outside of the Americas and is shown in Table 20 (BNEF 2015).

Table 20. Number of Offshore Projects by Location and Commissioned Between 2012 and 2015

Geographic Location	Number of Projects
United Kingdom	37
Europe (except UK)	35
Asia (Japan, China, Korea)	24

Projects connected to the grid in 2015 included 129 MW in the Netherlands, 1,055 MW in the United Kingdom, and 2,647 MW in Germany (EWEA 2015b). The projects were closely split between those being financed using a balance sheet (53%) and traditional project financing (47%), with both structures having their own debt/equity split. Pricing for offshore wind in Europe is reported to be between 250 and 350 basis points above the London Interbank Offered Rate, or LIBOR (20 to 50 basis points premium above land-based wind projects), and with interest rates hedging over the full loan amortization period, all-in market interest rates appear to range from 4.0% to 5.0% (Freshfields 2014).

From a European trend perspective, analysts anticipate that the shift toward more debt financing will continue as lenders gain experience with the sector and as utilities and sponsors require more capital. More than a dozen large-project finance banks are active in the space, investing as a club and syndicating further to smaller banks entering the arena. Historically, strong public policy and pricing support along with multilateral lending supported the growth of offshore wind in Europe, but debt investors are becoming more comfortable as the offshore industry matures. Equity yields in the European Union can range depending on the investor type, leverage, and incentives, and are typically between 11% and 15%.

5.6.2 Risk and Description of Risk Factors

At the end of 2015, there were no offshore wind projects installed in the United States. Even though the first U.S. offshore wind project became operational in 2016, limited experience in the U.S. market creates substantial uncertainty for investors. U.S. offshore wind project developers have identified risk and its impacts on the availability and cost of capital as a key barrier to the implementation of planned projects (Lannard 2011). Table 21 provides risk categories, specific examples, and mitigation strategies that developers are adopting (Guillet 2007; Mous 2010; Tassin 2010; Claveranne 2011).

Table 21. Offshore Project Risk Categories and Mitigation Strategies

Risk Category	Description/Examples	Mitigation Strategies
Development Risk	• Project viability – Permits – Power offtake – Sufficient capital for development • Debt versus equity ratios • Seabed characteristics	• Community engagement • Robust project management • Sponsor commitments • Due diligence to ensure that all permits, licenses, and authorizations are in force • Detailed surveys of each site
Financing Risk	• Attract sufficient debt/equity capital to cover project investment • Once operational, revenue must cover payment obligations	• Planning, engaging likely financiers early • Diligent permitting/contract structuring • Fixed price for generated power • Conservative, validated estimates

Risk Category	Description/Examples	Mitigation Strategies
Construction Risk	• Delays and cost overruns – Currency risk/commodity price risk – Severe weather – Contractor delays – Accidents • Responsibility for problems (liability) – Limited engineering, procurement, construction wraps for offshore wind – Multiparty contracts have interfaces between contracts in which liability for risk events may be unclear	• Analysis of downside scenarios • Preparation of contingency fund • Insurance • Strong contracts—identification of interfaces and clear allocation of responsibility • Due diligence to validate design and engineering
Operations Risk	• Lower availability – Turbine accessibility – Vessel availability – Limited operational experience with new turbines • Cost overruns – Accidents – Serial design flaws in early projects (e.g., monopile grout) – New turbine technology (5 MW+) – Limited long-term track record • Export cables and offshore substation failures	• Smart warranty design with emphasis on revenue protection • Long-term service agreement • OEM commitment • Insurance • Conservative planning and budgeting • Due diligence to validate assumptions
Volume Risk	• Energy production lower than expected – Lower wind resource – Availability – Array effects, losses – Curtailments	• Conservative wind resource estimates • Insurance • Priority dispatch agreement • Due diligence to validate assumptions
Price Risk	• Lower prices than forecast – Changes to regulations or incentives – Court cases challenging offtake contract – Market volatility	• Fixed price contract (PPA or feed-in tariff) • Conservative projections
Jones Act Risk	• Vessel availability – U.S.-flagged vessels must be used between U.S. ports – Substantial capital investment to build U.S.-flagged vessel	• U.S-constructed vessel • 75% of vessel owned by U.S. citizens • Overall vessel control in hands of U.S. citizens • Apply European learning curve knowledge

As offshore wind projects are implemented in Europe, investors are using lessons learned to develop effective strategies to manage their risk exposure. European governments have historically helped investors to gain comfort with the technology by offering public loans or loan guarantees to reduce exposure to downside risks, designing incentives to provide revenue certainty, and protecting offshore wind generation from curtailment. The European strategy may be effective—18 commercial banks participated in the 2015 market versus 14 commercial banks in 2013.

As noted above, the lack of installed offshore wind projects in the United States creates uncertainty about the ability of the nascent industry to deliver projects within the planned budget. In addition, there is the added risk of how an offshore wind project will be treated in the untested U.S. regulatory framework. The lack of experience means that investors cannot, with reasonable accuracy, identify the probability of an unfavorable event or the potential impact that such an event could have on project cash flows. Such ambiguity makes investors uncomfortable and limits enthusiasm to commit unsecured capital to the early offshore wind projects. The initial experience financing the Block Island Wind Farm, however, shows that investors are willing to finance strong projects with long-term offtake agreements.

5.6.3 Discount Rate and Fixed Charge Rate

Previous evaluations of the discount rate for the offshore wind finance study have focused on the European experience and on the blended discount rate of approximately 10.5% proposed by Cape Wind and Deepwater Wind for their respective project return limits. Although it is evident that an individual project's financing terms will reflect the individual risk profile of that project, new baseline assumptions and ranges of nominal discount rates for offshore wind have been developed based largely on observations from the European market, as well as available information about financing for the Block Island Wind Farm in the United States. Underlying assumptions for marginal tax rate and inflation are consistent with those presented in Section 4.6.

As previously stated, projects were either balance sheet or project financed. It was assumed that the balance-sheet projects had a 50% debt/equity split with a 4% pretax debt rate and 9% after-tax equity rate, which results in a real WACC of 6%. Regarding the project-financed projects, there was a 60% debt with a 5% pretax rate and the 40% equity had a 12% after-tax rate resulting in a 7% real WACC. To estimate a WACC for the 2015 reference project, the two project-financed scenarios were weighted assuming that about 55% of the 2015 offshore wind installed capacity utilized balance-sheet financing and about 45% of the installed capacity utilized project-financed structures. Both the balance-sheet and project-financed rates will be used in the sensitivity analysis later in this report. Table 22 summarizes the two scenarios, with the third scenario being the WACC used for the LCOE analysis of the representative offshore wind projects.

Table 22. Offshore After-Tax Discount Rates in 2015

Scenario	Nominal Discount Rate	Real Discount Rate
Balance-sheet scenario (debt 50%/equity 50%)	8.65%	6.0%
Nonrecourse project-financed scenario (debt 60%/equity 40%)	9.67%	7.0%
2015 reference project	9.13%	6.47%

5.6.4 Economic Evaluation Metrics

To determine the LCOE for the 2015 representative offshore wind project, an FCR was used (see Section 4.6). The FCR includes the present value of the accumulated depreciation benefit and ignores bonus depreciation. Assuming a project life of 20 years and discount rates and depreciation benefits as calculated, Table 23 presents the two financing scenarios and the WACC-based FCR that was used throughout the analysis. The details and calculations are summarized in Appendix B.

Table 23. Offshore After-Tax Fixed Charge Rates in 2015

Scenario	Nominal FCR	Real FCR
Balance sheet	12.1%	9.9%
Nonrecourse project financed	13.2%	10.8%
2015 reference project	**12.6%**	**10.3%**

5.7 Offshore Wind Reference Project Summary

The resources, database, and analysis described in this section informed the creation of the reference project shown in Table 24. The 2015 reference project is defined with 145 turbines on monopile foundations and an average water depth of 30 m. In addition, turbines rated at 4.14 MW with a 118.9-m rotor diameter and 90.3-m hub height were assumed. The average wind speed at the project site was assumed to be 8.4 m/s at 50 m and 8.91 m/s at the 90.3-m hub height (typical North Atlantic wind regime).[28] This gave the U.S. fixed-bottom offshore reference project an AEP of 3,608 MWh/MW/yr, which is a net capacity factor of 41.2%, and the floating offshore reference project an AEP of 3,595 MWh/MW/yr, which results in a net capacity factor of 41.0%.

These turbine parameters are characteristics that are specific to the turbine and independent of the wind resource characteristics. These parameters consist not only of turbine size (such as rated power, rotor diameter, and hub height), but also of turbine operating characteristics (such as coefficient of power [C_p], maximum tip speed, maximum TSR, and drivetrain design). Because the three-stage planetary/helical gearbox with a high-speed asynchronous-generator-style-drivetrain topology dominates the global market, it was selected for the baseline turbines used in this analysis. Because of changes in technology, future projects could be using either direct-drive wind turbines (e.g., GE Haliade) or medium-speed technology (e.g., Vestas V164) instead of the high-speed asynchronous generator as more commissioned projects use this technology.

In the reference project layout, the turbines are spaced in a grid formation at 9 rotor diameters apart and connected to the substation using a radial 33-kilovolt collection system design and a 220-kilovolt export system. Reference project costs for 2015 were based on global average market data and NREL models. The CapEx of the fixed-bottom project was estimated to be $2.87 billion, or about $4,615/kW, including a contingency estimated at 10% of installed capital costs. The annual OpEx is equivalent to $49.6/MWh/yr, or $179/kW/yr. The floating project

[28] Average wind speed assumes a Weibull (k = 2.1) probability distribution.

CapEx was estimated to be $4.13 billion, or about $6,875/kW with an annual OpEx of $37.4/MWh/yr, or $138/kW/yr.

The reference project WACC or discount rate assumed to finance the project is a composite, equivalent of the methodology for land-based projects and estimated to be 9.13% nominal after tax (6.47% real after tax), resulting in a real FCR of 10.3%.

Table 24. Offshore Reference Project Assumptions Summary (Fixed Bottom and Floating)

General Assumptions	
Project capacity (MW)	600
Number of turbines	145
Turbine capacity (MW)	4.14
Site	
Location	North Atlantic Coast
Depth (m)	30/100
Distance from shore (km) [fixed/floating]	30
Wind speed (m/s at 50 m above mean sea	8.4
Wind speed (m/s at 90 m above mean sea	8.91
Net capacity factor [fixed/floating]	41.2%/41.0%
Technology	
Rotor diameter (m)	118.9
Tower height (m)	90.3
Gearbox	Three stage
Generator	Asynchronous
Foundation	Monopile
Cost (Nominal 2015 USD)	
Capital cost (millions) [fixed/floating]	$2,872/$4,125
Contingency (10% of hard costs in million $; fixed/floating)	$287/$413
Annual OpEx ($/MWh) [fixed/floating]	$49.6/$37.4
Discount rate (real)	6.47%
Discount rate (nominal)	9.13%
Operating life (years)	20
FCR (real)	10.3%

5.8 Offshore Wind Levelized Cost of Energy Calculation

Table 25 summarizes the offshore wind technology reference projects, fixed-bottom and floating substructures, by providing the component cost categories for the 4.14-MW turbines in the project as well as the LCOE calculation results. A comprehensive summary of assumptions can be found in Appendix A. Estimates of the percentage contribution of individual project components to total capital costs were developed for each component based on the aforementioned global offshore market data and NREL cost models. The NREL OWDB (NREL 2013) and cost models enable the development of an improved understanding of scaling relationships and opportunities for technology improvement.

Table 25. Offshore Wind LCOE and Reference Projects Cost Breakdown

	Fixed Bottom	Floating
CapEx	$4,615/kW	$6,647/kW
OpEx	$179/kW/yr	$138/kW/yr
AEP_{net} (MWh/MW/yr)	3,608	3,595
Net capacity factor	41.2%	41.0%
FCR (real, after tax)	10.3%	10.3%
LCOE ($/MWh)	**181**	**229**

The 2015 NREL reference offshore wind project has an LCOE of $181/MWh for fixed-bottom and $229/MWh floating foundations. The 43% increase in CapEx shown in Table 25 is driven by the increased current cost of the floating substructure compared to a traditional fixed-bottom substructure. The floating substructure requires dramatically more steel and fabrication time. Figure 16 and Figure 17 show the cost breakdown for the project. These modeled results are within the range of LCOE values discussed in Beiter et al. (2016) for projects that could be commissioned in 2015. Expectations for a sharp decline in LCOE for projects to be commissioned in the next 2-4 years are discussed in the upcoming text box.

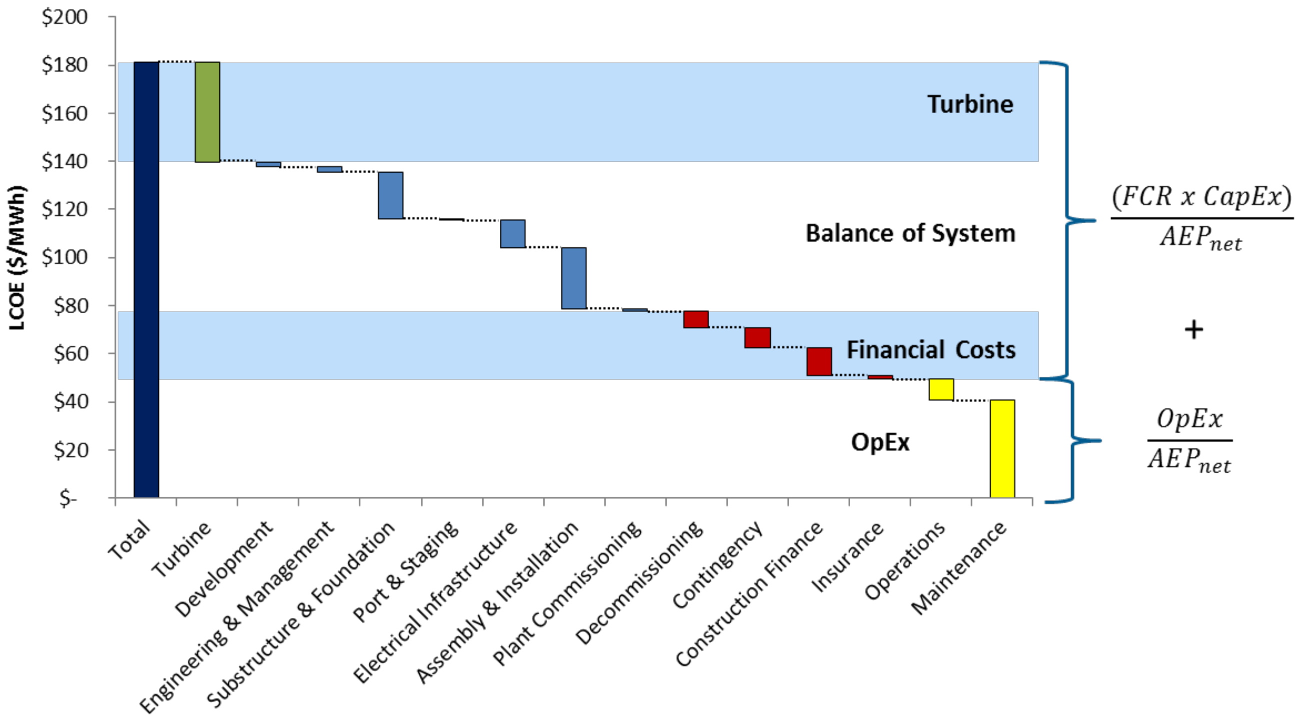


Figure 16. Cost breakdown for the 2015 fixed-bottom offshore wind reference project
Source: NREL

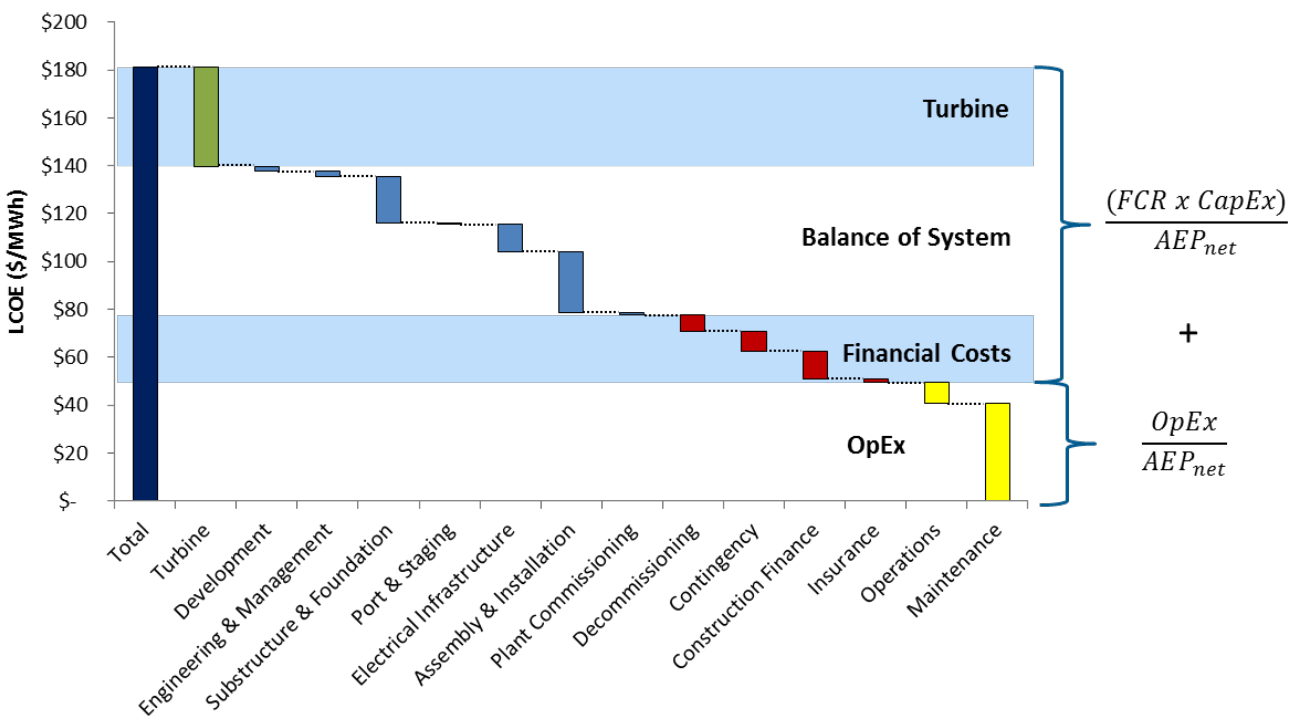


Figure 17. Cost breakdown for the 2015 floating offshore wind reference project
Source: NREL

Recent European Offshore Wind Project Cost Projections

Literature review of recently signed tenders for offshore wind projects in Europe shows a dramatic drop in the cost of energy for projects expected to be commissioned in the next several years. Tenders or strike prices are not directly comparable to LCOE (similar to PPA prices), but they do provide insight into cost expectations. Based on project characteristics and expected revenue, Harries (2015, 2016a, 2016b, 2016c) calculated LCOE values from $40/MWh to $66/MWh for projects that will become operational between 2019 and 2021. These projects include Borssele I and II, Vesterhav Syd and Vesterhav Nord, Kriegers Flak, and Borssele III and IV, which will be located in the Netherlands and Denmark. These calculated LCOE estimates suggest a sharp decline relative to projects installed in 2015.

Several factors contribute to these low LCOE estimates that may or may not translate to other offshore wind plants planned in the future. These projects are in shallow water and close to shore. In the case of the Vesterhav project, the distance likely eliminates the need for a substation. These projects will use larger turbines, likely 7-8 MW, such that the number of turbines required for a 600-MW project is half that of a project using 4-MW turbines. In addition, much of the development and transmission costs are borne by the respective governments or electric system operators rather than the project developer. Financing structures used in Europe have been maturing over the past several years, resulting in alignment of the timing of capital expenditures and a decline in the risk premium for offshore wind plants. As these projects and others currently in planning stages proceed, the impact of these factors on U.S. projects will become evident.

5.9 Offshore Wind Levelized Cost of Energy Sensitivities

The costs and operational parameter inputs of a near-term offshore wind project are subject to considerable uncertainty similar to that for land-based projects. The sensitivity analysis shown in Figure 18 and Figure 19 focuses on the basic LCOE inputs: CapEx, OpEx, capacity factor (a surrogate for AEP), discount rate, and operation lifetime (surrogates for FCR). Sensitivities were tested by holding all other variables constant. The reference estimate for each parameter is represented by the vertical white line within each bar. Specific high and low values are shown within each colored bar. The range of AEP_{net} estimates around this baseline extends from 3,066 to 4,555 MWh/MW/yr, which corresponds to the range of capacity factors (35%–52%) observed in Europe.

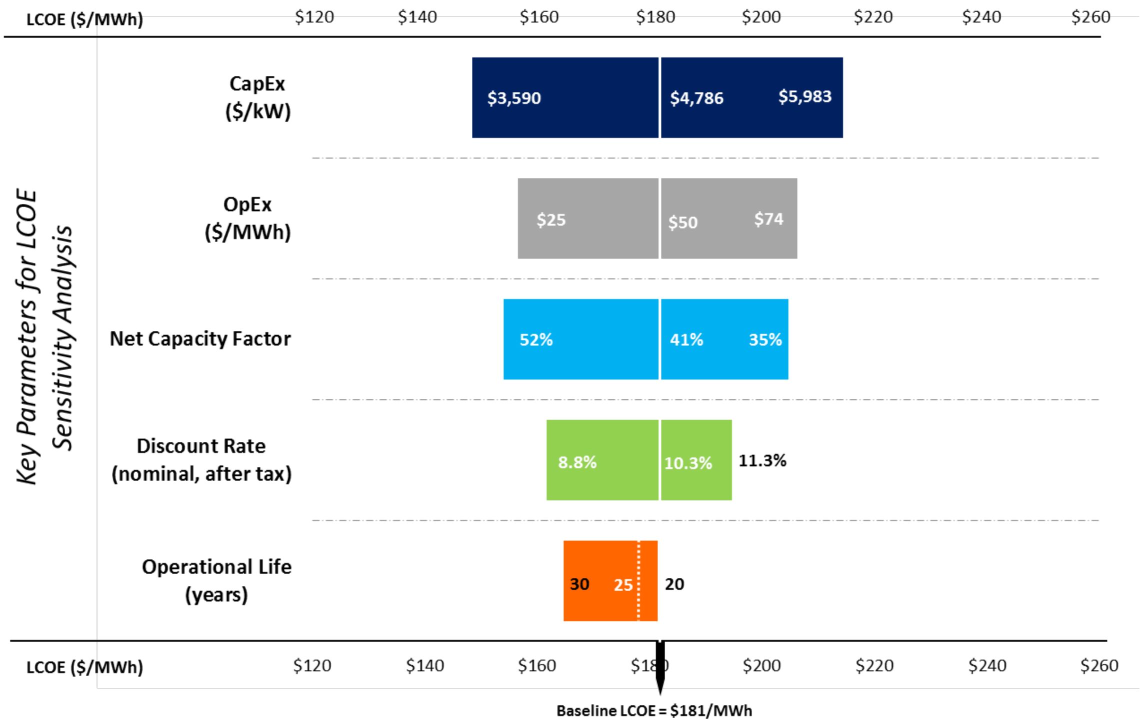


Figure 18. Sensitivity of fixed-bottom offshore wind LCOE to key input parameters
Source: NREL

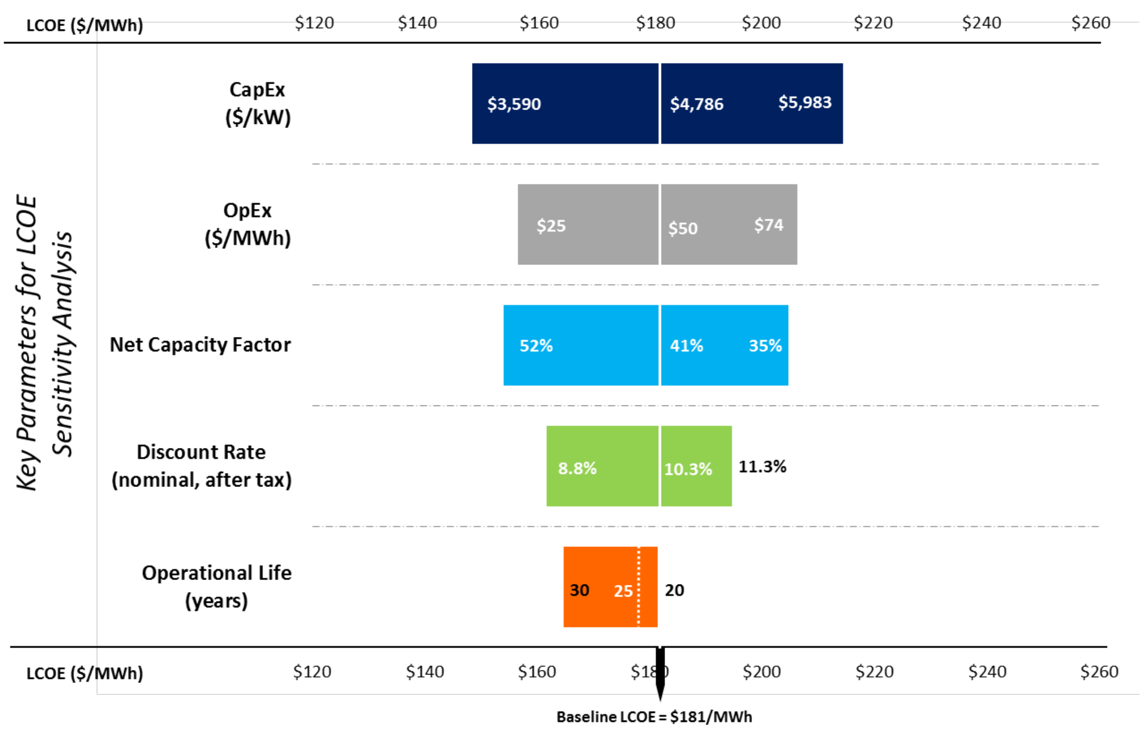


Figure 19. Sensitivity of floating offshore wind LCOE to key input parameters
Source: NREL

Note: The reference LCOE provides a representative estimate of the offshore wind LCOE, assuming commercial-scale fixed-bottom or floating technology. Changes in LCOE for a single variable can be understood by moving to the left or right along a specific variable. Values on the x-axis indicate how the LCOE will change as a given variable is altered and assuming that all others are constant (i.e., the variables remain reflective of the reference project).

During the analysis, sensitivity ranges were selected to represent the highs and lows seen in the industry. This selection of ranges provides insight into how real-world variability influences LCOE. Figures 18 and 19 show a very wide range of LCOE outcomes, extending from $152 to $285/MWh; however, as noted in the earlier discussion of land-based sensitivities, the high and low LCOE ranges should not be taken as absolute because these variables are not typically independent. For offshore wind projects, the COE is most sensitive to CapEx and capacity factors, and appears to be somewhat less sensitive to operating life and discount rate.

6 Nominal Versus Real Dollar Effects and Historical LCOE

In 2010, DOE set LCOE targets for both land-based, $57/MWh in 2020 (real 2010 dollars) and $42/MWh in 2030 (real 2010 dollars), and offshore wind, $167 (real 2010 dollars) in 2020 and $136/MWh (real 2010 dollars) in 2030 (DOE 2013). The official DOE reports in the Congressional Budget Justification for the Government Performance and Results Act publications have tracked the LCOE to gauge progress towards reaching the stated 2020 and 2030 goals.

Table 26 and Table 27 summarize the trends of land-based LCOE and fixed-bottom offshore LCOE that NREL has been assessing since 2010. There has been no floating offshore LCOE assessed in past reports and it is therefore not shown in these tables. LCOE results in 2010 and 2011 differ from the NREL published reports because the methodology for estimating OpEx was changed.[29]

Table 26. Historical Land-Based LCOE as Reported in the Cost of Wind Energy Reviews (Nominal Dollars)

Parameters	2010 COE	2011 COE	2012 COE	2013 COE	2014 COE	2015 COE
Nameplate capacity (MW)	1.5	1.5	1.94	1.9	1.94	2.0
Rotor diameter (m)	82.5	82.5	93.5	96.9	99.4	102.0
Hub height (m)	80	80	80	82.7	82.7	82.1
Modeled net capacity factor (%)	38.0	37.0	37.5	38.5	39.6	39.9
CapEx ($/kW)	2,155	2,098	1,940	1,728	1,710	1,690
FCR (%)	9.5	9.5	9.5	10.2	10.3	9.6
OpEx ($/kW/yr)	55	55	55	50	51	51
AEP (MWh/MW/yr)	3,345	3,263	3,284	3,410	3,466	3,494
LCOE ($/MWh)	**78**	**78**	**73**	**66**	**65**	**61**

[29] In the previous cost of wind energy reviews, the authors used an after-tax operational expenditure that affected the labor, equipment, and facilities portion of the OpEx. The methodology of using only a pretax value was established in 2012. To compare the historical LCOE values and represent the trends, the 2010 and 2011 OpEx were modified to align with the current methodology.

Table 27. Historical Offshore LCOE as Reported in the Cost of Wind Energy Reviews (Nominal Dollars)

Parameters	2010 COE	2011 COE	2012 COE	2013 COE	2014 COE	2015 COE
Nameplate capacity (MW)	3.6	3.6	3.6	4.3	3.39	4.14
Rotor diameter (m)	107	107	107	119.4	115.4	118.9
Hub height (m)	90	90	90	89.5	85.8	90.3
Modeled net capacity factor (%)	39.0	39.0	39.0	39.0	42.4	41.2
CapEx ($/kW)	5,600	5,600	5,384	5,187	5,925	4,615
FCR (%)	11.7	11.7	11.7	11.7	9.8	10.3
OpEx ($/kW)	136	136	136	136	138	179
AEP (MWh/MW/yr)	3,406	3,406	3,406	3,463	3,716	3,608
LCOE ($/MWh)	**232**	**232**	**225**	**215**	**193**	**181**

The LCOE values are reported annually in nominal dollars to represent the actual cost of energy for a given year. However, since 2010, the baseline goal has never been adjusted for inflation even though the LCOE values reported annually include inflation. This means that the 2020 and 2030 goals are stated in real 2010 USD, whereas the annual values are reported in the nominal current year dollars.

Real dollars, or pricing, represent the value that has been adjusted for inflation from some base year, which in this case is 2010. Nominal dollars or pricing represent the actual price that would have been paid in the given year. The differences in the LCOE values in Table 28 represent the difference of cumulative inflation between real and nominal dollars. For the time period in this report, 2010–2015, the cumulative 5-year inflation is assumed to be 8.7% (Bureau of Labor Statistics 2016).

Table 28 and Figure 20 represent the effects of inflation on land-based wind for annual reports of LCOE to the Government Performance and Results Act and Congressional Budget Justification in nominal and real dollars. For a direct comparison of the changes in LCOE, DOE reporting tries to eliminate the effect that market has on financing and uses a constant discount rate of 7%, which equates to a FCR of 10.8% in the official reports. The 2020 and 2030 LCOE inputs—CapEx, OpEx, and AEP—are derived from the cost of wind energy review estimates from prior years (i.e., 2010 COE from Table 26 appears in the Fiscal Year 2011 column of Table 28).

Table 28. Land-Based Wind LCOE Reported Values in Nominal and Real Dollars from FY 2010 to FY 2020

	Fiscal Year								
	2010	2011	2012	2013	2014	2015	2016	2020	2030
CapEx (nominal $/kW)	2,120	2,155	2,098	1,940	1,728	1,710	1,690	1,475	1,200
Real discount rate (%)	7%	7%	7%	7%	7%	7%	7%	7%	7%
OpEx (nominal $/kW/year)	44	55	55	55	50	51	51	47	39
Net annual energy production (MWh/MW/year)	3,133	3,345	3,263	3,284	3,410	3,466	3,494	3,600	3,975
LCOE (nominal $/MWh)	**82**	**80**	**80**	**74**	**69**	**68**	**67**	**N/A**	**N/A**
LCOE (real $2010/MWh)	**82**	**80**	**77**	**70**	**65**	**63**	**62**	**57**	**42**

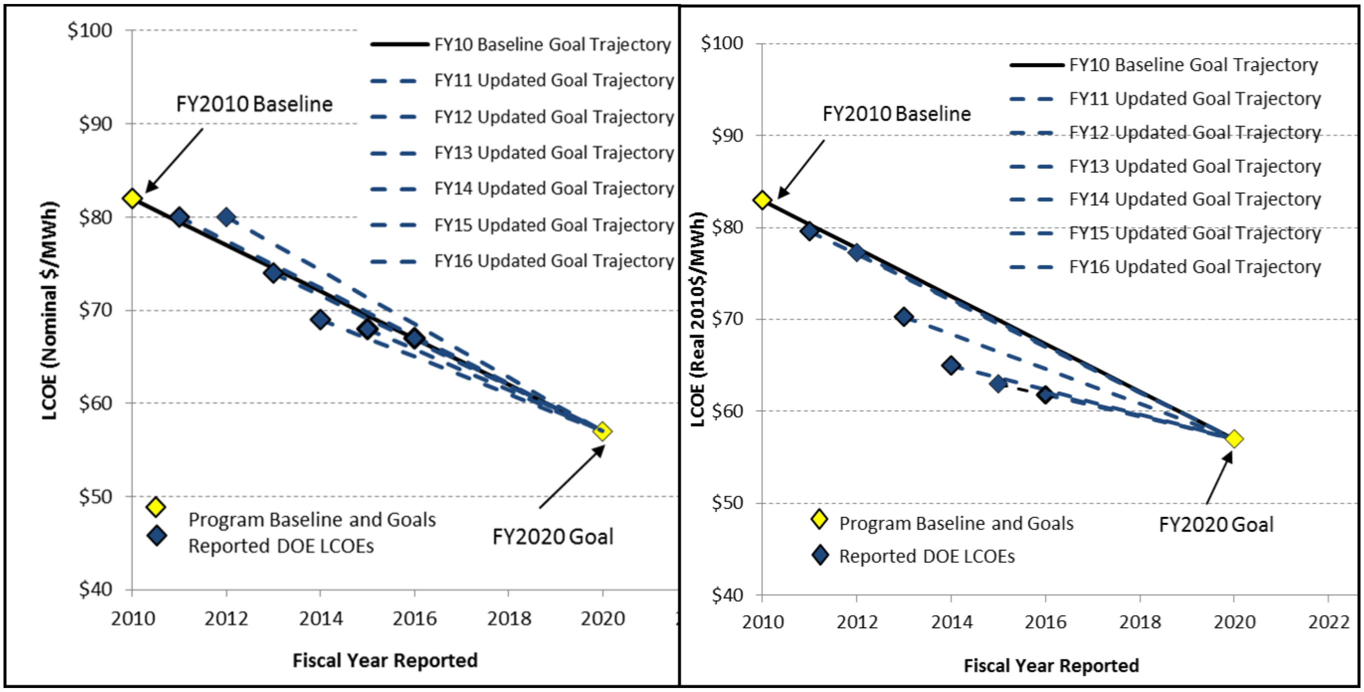


Figure 20. Land-based wind LCOE goals, interim trajectories, and reported values in nominal (left) and real (right) dollars from FY 2010 to FY 2020

Source: NREL

In real 2010 dollars, DOE has achieved 81% of the LCOE reduction to achieve the stated goals of $57/MWh in 2020. However, when mixing the inflation-adjusted nominal values listed in Table 28 with the real 2010 dollar goal of $57/MWh in 2020, DOE has achieved only 60%. This highlights the importance of comparing the equivalent dollar years, whether nominal or real, when discussing any cost reduction metric.

7 Understanding Trends in Wind Turbine Prices: An Update

7.1 Introduction

Accounting for roughly two-thirds of the total installed cost of a wind project (Wiser and Bolinger 2016), wind turbine prices are the largest component of wind's LCOE. After having roughly doubled in price from 2001 through 2008, wind turbine prices have fallen by roughly 40% through 2015 (Figure 21), helping to push wind's LCOE to new lows. Reducing wind turbine prices and LCOE even further is a key goal of the wind industry and U.S. government alike.

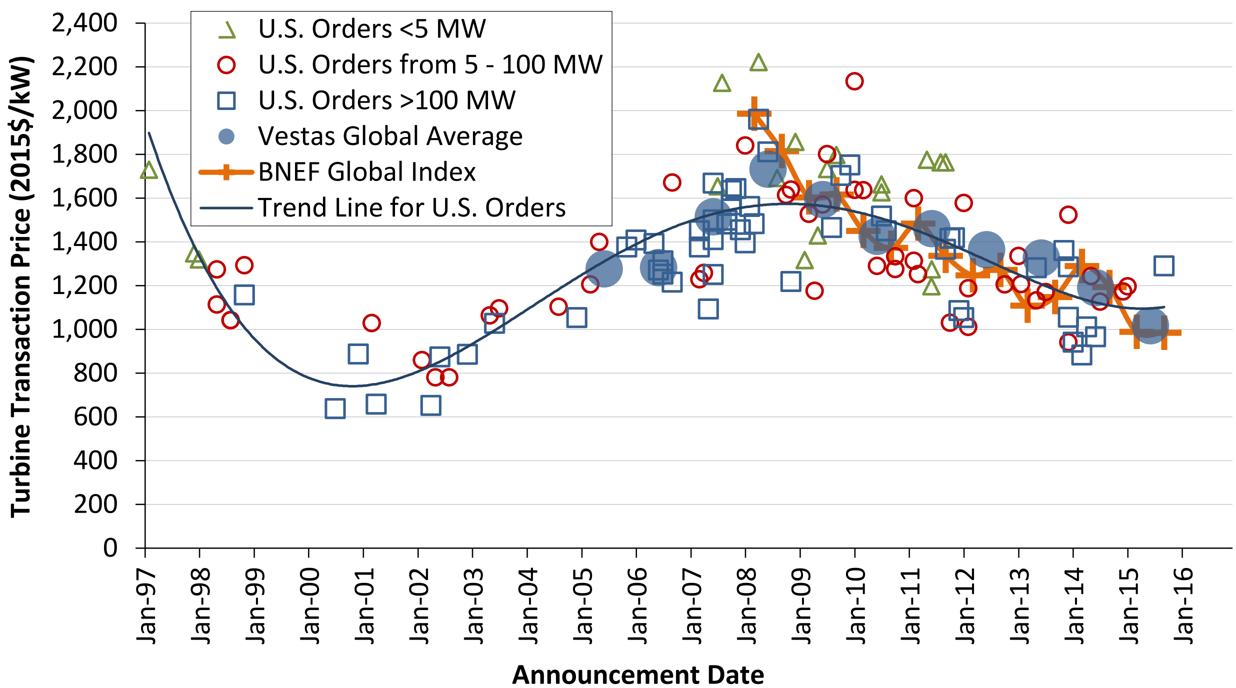


Figure 21. Reported wind turbine transaction prices over time
Source: Wiser and Bolinger (2016)

At the same time, a variety of factors influence wind turbine prices, and although some of those drivers are "endogenous" in the sense that they can be influenced by industry- and government-sponsored research and development programs and deployment-related learning, other "exogenous" drivers fall largely outside of the industry's control. As categorized in Bolinger and Wiser (2011, 2012), which explored seven different drivers behind the doubling in turbine prices from 2001 through 2008 and the subsequent decline through 2010, endogenous variables include (but are not necessarily limited to) labor costs, warranty provisions, and profit margins at turbine manufacturers and component suppliers, as well as turbine design changes like increased capacity, hub height, and rotor diameter. Meanwhile, exogenous variables include, but are not necessarily limited to, prices for raw materials and energy and movements in foreign exchange rates.

This section updates—and revises somewhat[30]—the analysis behind Bolinger and Wiser (2011, 2012) to gain insight into the extent to which each of these endogenous and exogenous variables have contributed to turbine price declines since 2010 (when the analysis underlying the original report left off). In addition to updating and revising the previous analysis, it also evaluates one potential future scenario in which turbine prices could rise as a result of adverse movements in commodities prices and exchange rates in particular (i.e., a reversal of the extended period of commodity price weakness and dollar strength that has benefited turbine prices in recent years).

In the interest of expediency, this section does not rehash much of the contextual material discussed in Bolinger and Wiser (2011, 2012), but references that prior work extensively, while focusing on new and updated findings.

7.2 Endogenous Drivers

As was the case in Bolinger and Wiser (2011, 2012), our analysis of three of the four endogenous drivers examined here—namely labor costs, warranty provisions, and profitability—relies largely if not exclusively on data from Vestas. In addition, the fourth endogenous driver—turbine scaling—relies on mass data obtained from life cycle analyses of several different Vestas turbines (and conducted by Vestas). Although such heavy reliance on data from a single turbine manufacturer is not ideal, Vestas is one of only a few publicly traded pure-play turbine manufacturers, and among that select group has the largest presence in the U.S. market.[31] Furthermore, as shown in Figure 21, Vestas' global-average-implied turbine pricing has closely tracked prices in the U.S. market, providing at least some comfort that, in a competitive U.S. market, data from Vestas can, to some extent, serve as a surrogate for the entire market.

7.2.1 Labor Costs

As reported in the company's annual financial reports, Vestas' staff costs (expressed here in 2015 $/kW terms) rose more or less steadily through 2011, before declining over the subsequent 3 years (as the result of a concerted cost-cutting effort) and then remained flat in 2015 (Figure 22). Just as the increase in labor costs was a driver of the doubling in turbine prices from 2001 through 2008, the decline in labor costs since 2011—though not quite back to 2001 levels—is one factor that has enabled lower turbine prices over this period.[32]

[30] As explained in more detail later, there are three primary departures from the approach taken in Bolinger and Wiser (2011): the use of earnings before interest, tax, depreciation and amortization rather than earnings before interest and taxes to track profitability; reliance on empirical turbine mass data rather than NREL modeling to track scaling effects; and showing the effects of foreign exchange rate movements as a range (to reflect uncertainty over exchange rate pass-through) rather than as a single-point estimate.

[31] GE dominates the U.S. market but is not a pure-play turbine manufacturer and does not segment its financial reporting to reflect its wind turbine business. Siemens—the third of the "Big 3" or "Tier 1" turbine suppliers in the United States (in addition to GE and Vestas)—is also not a pure-play turbine manufacturer and has only sporadically segmented its financial reporting around wind turbines.

[32] The numbers shown in Figure 22 reflect total staff costs—i.e., including Vestas' turbine servicing business—and not just those staff costs associated with manufacturing turbines (which would have been ideal for this purpose). In each of the past few years, service revenue has made up ~15% of total revenue at Vestas (up from ~5% in the 2004–2006 period).

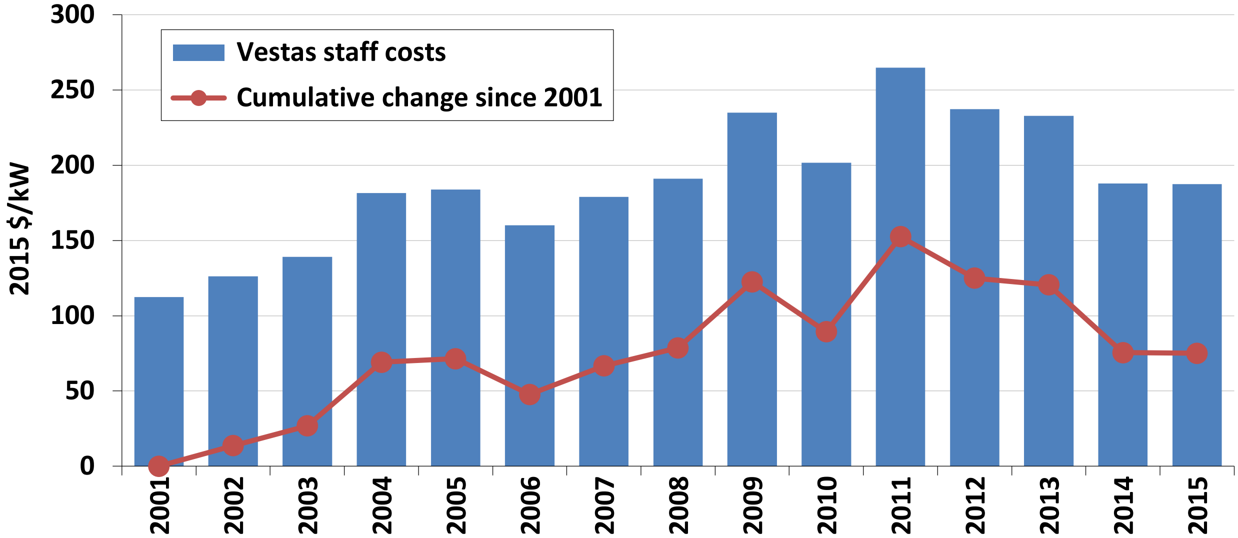


Figure 22. Vestas total staff costs
Source: Vestas 2001-2015 annual reports

7.2.2 Warranty Provisions

A sharp increase in warranty provisions (i.e., funds reserved to cover expected warranty claims) through 2005, with resulting high provision levels largely maintained through 2009, was one factor leading to an increase in wind turbine prices from 2001 through 2008. A concerted effort to improve product quality was launched in 2005, however, it did not begin to bear fruit until late in the decade as warranty provisions dropped considerably in 2010 and have continued to drift lower ever since—almost back to 2001 levels in 2014 and 2015 (Figure 23).

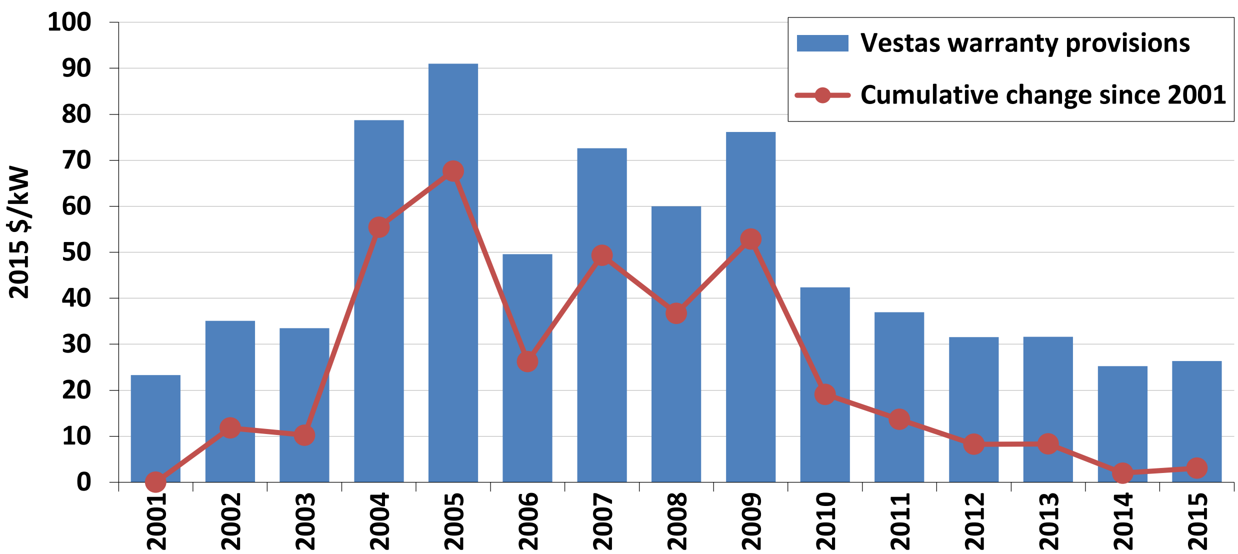


Figure 23. Vestas warranty provisions
Source: Vestas 2001-2015 annual reports

7.2.3 Turbine Manufacturer Profitability

In addition to reflecting changes in underlying costs—of labor, warranty provisions, raw materials, and energy (as documented elsewhere in this section)—turbine prices can also be affected by changes to profitability over time, independent of costs. Although Bolinger and Wiser (2011, 2012) used Vestas' operating profit (i.e., earnings before interest and taxes, or EBIT) to gauge profitability through 2010, this update relies instead on Vestas' earnings before interest, taxes, depreciation, and amortization (EBITDA). As shown in Figure 24, Vestas's EBITDA closely tracked EBIT through 2008 but has since been much less volatile. In particular, Vestas suffered an unusually large loss in EBIT in 2012 that was not similarly reflected in its EBITDA. This differentially larger loss in EBIT was primarily driven by depreciation, which is largely an accounting convention that should not necessarily impact near-term product pricing. Furthermore, compared to other publicly traded pure-play turbine manufacturers (i.e., Gamesa, Nordex, and Goldwind), Vestas' 2012 loss of EBIT appears to have been excessive, whereas its EBITDA margins were more in line with those other manufacturers (Wiser and Bolinger 2016). Hence, this update to Bolinger and Wiser (2011, 2012) switches the profitability metric from EBIT to EBITDA, resulting in only minimal changes to the 2001–2010 period covered by that earlier publication. As shown in Figure 24, turbine price declines since 2012 have occurred in spite of a strong increase in profitability at Vestas (and, as shown in Wiser and Bolinger [2016], at other turbine manufacturers as well).

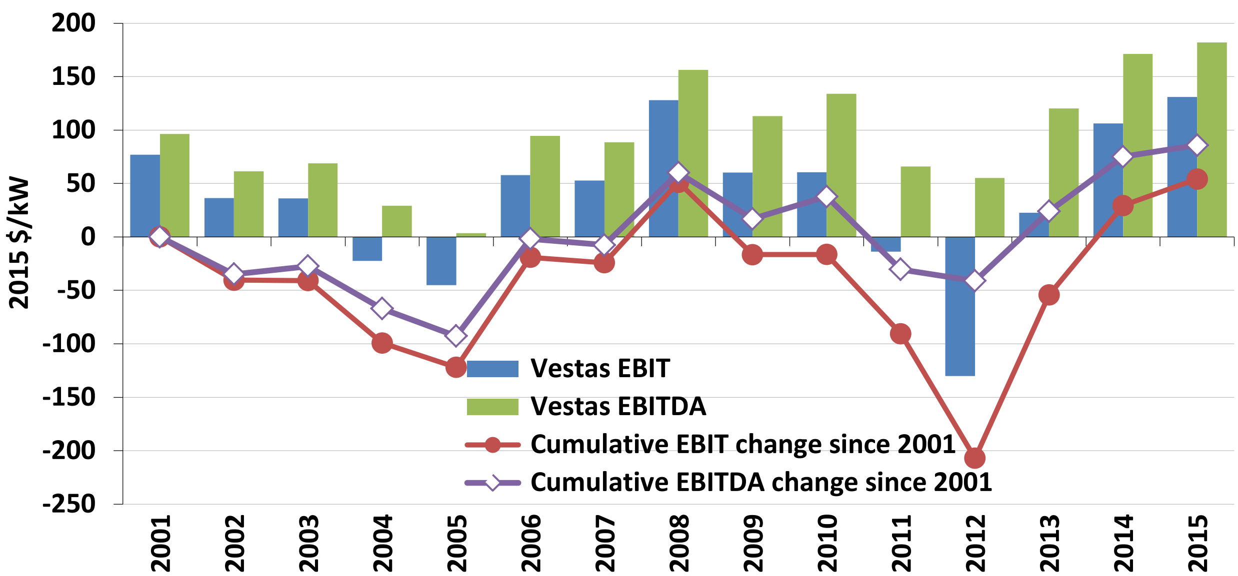


Figure 24. Two measures of profitability at Vestas: EBIT and EBITDA

Source: Vestas 2001-2015 annual reports

7.2.4 Increasing Turbine Size and Energy Capture

Perhaps the biggest departure from the methodology in Bolinger and Wiser (2011, 2012) comes in the measurement of the impact of turbine scaling. Bolinger and Wiser (2011, 2012) used the NREL CSM described in Fingersh, Hand, and Laxson (2006) to measure the effect of increasing nameplate capacity, hub height, and rotor diameter on wind turbine prices. Even at the time, however, there was some concern that the significant scaling that had occurred through 2010 may have already begun to transcend the boundaries of the relationships underlying the original

NREL scaling model. [33] With the pace of scaling having accelerated since 2010—for example, among projects installed in the United States in 2015, the average rotor diameter was 21% and 36% larger than in 2010 and 2005, respectively—NREL's original (2006) CSM is no longer an appropriate tool to measure the cost impact of scaling through 2015.

Fortunately, an alternative and more empirical approach that was not available to Bolinger and Wiser (2011, 2012) has since become available, thanks to a relatively recent campaign by Vestas to conduct numerous life cycle analyses (LCAs) across its various turbine platforms. Among other things, these analyses yield a wealth of data on the mass of raw materials used in the manufacture of Vestas turbines of various sizes and designs. To a degree, these mass data provide an empirical history of the impact of evolutionary turbine scaling on raw materials usage, which, in turn, can be used to estimate the corresponding impact of turbine scaling on turbine costs and prices. Before proceeding, however, it is important to note that Vestas is only one of several major turbine suppliers to the U.S. market, and that these mass data from Vestas may not be entirely representative of other wind turbine makes and models (e.g., the GE turbines that have historically captured the largest market share in the United States).

To use the LCAs for this purpose, each calendar year was paired with the LCA of a turbine whose specifications most closely matched the average capacity, hub height, and rotor diameter of turbines deployed in the United States in that year. The results of this matching process are shown in Figure 25, in which the solid lines with colored markers represent the empirical average fleet data and the dashed lines with white markers represent the corresponding LCA turbine specifications (the assigned LCA turbine models for each year are shown along the secondary x-axis at the top of the graph). In general, the assigned LCA turbine specifications match up reasonably well with the fleet averages. Because mass data for Vestas turbines smaller than the V82 1.65 MW model were not available, mass data for NEG Micon and Nordex turbines, sourced from Liberman (2003), were used prior to 2006.[34]

[33] For example, Bolinger and Wiser (2011) caveated their results by noting that "…the NREL cost model relies on standard relationships between component size, weight, and other design parameters; to the extent that design innovation has fallen outside the bounds of these standard relationships, actual scaling-related cost influences may have differed from what is presented..."

[34] To facilitate a closer match between life cycle analysis turbine specifications and fleet averages, we averaged data from multiple life cycle analyses in 2001, 2002, and 2015. Specifically, in 2001 and 2002, we averaged mass data for two NEG Micon 900-kW turbines with 52-m rotor diameters but different tower heights of 49 and 72.3 m to yield an average tower height of 60.7 m in both 2001 and 2002, which more closely matches the empirical averages of 58 and 63 m, respectively. Similarly, in 2015, we averaged mass data for the V100 2.0 MW and V110 2.0 MW turbines (both with 80-m towers), yielding an average rotor diameter of 105 m. The V100 2.0-MW life cycle analysis would have also been an acceptable choice in 2015 (given the 102-m average empirical rotor diameter in that year), but we wanted to include the V110 data in our analysis, given that it is a Class IIIA turbine (compared to the V100's Class IIB rating), and Class III turbines were deployed in a majority of U.S. installations in both 2014 and 2015.

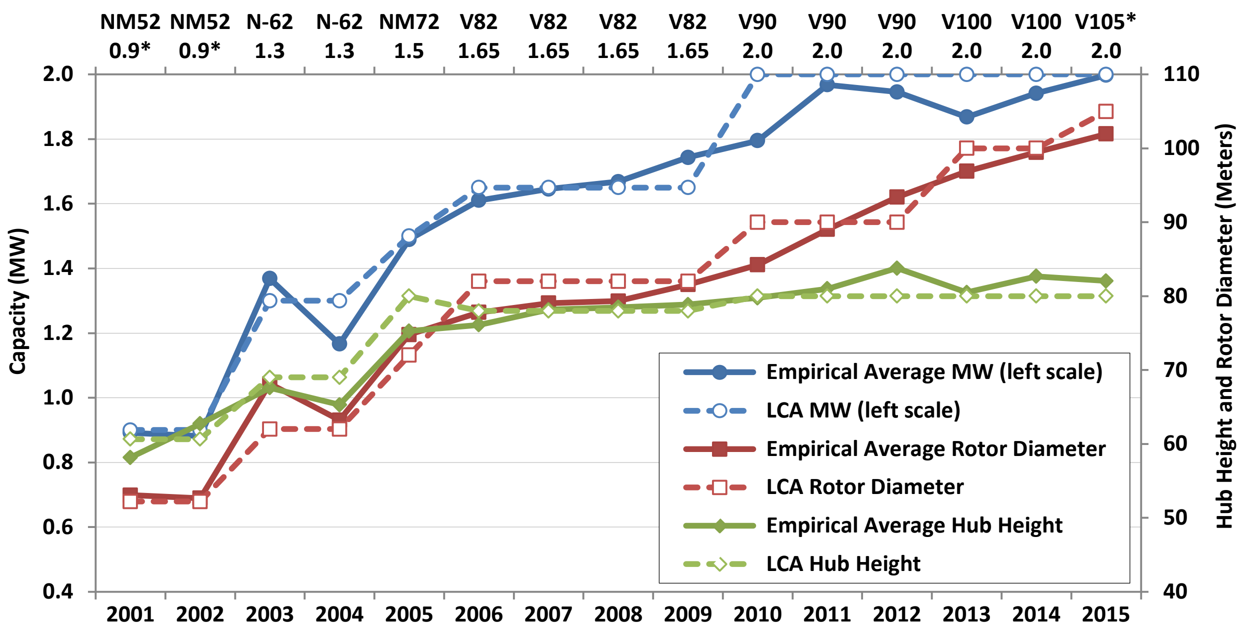


Figure 25. Average capacity, hub height, and rotor diameter of the U.S. fleet versus mapped LCAs

Sources: Liberman (2003); Vestas (2006); Garrett and Ronde (2011); Razdan and Garrett (2015a, 2015b); Wiser and Bolinger (2016)

*See footnote 34 regarding averaging of life cycle analysis data in 2001, 2002, and 2015

Figures 26 and 27 show how the “mass intensity”—expressed as kilograms (kg) of mass per kilowatt of nameplate capacity in Figure 26 and as kg of mass per m^2 of rotor swept area in Figure 27—of the primary materials that make up a wind turbine (accounting for ~98% or more of total turbine mass [see Table 30]), as well as the wind turbine as a whole, vary across the mapped/calendar year combinations.[35] In both figures, mass intensity has declined across all four materials categories, as well as for the turbine as a whole, as the LCAs progress from smaller to larger turbines over time. The reduction in mass intensity among the two most prevalent materials categories (steel/iron and fiberglass) in particular, and hence the total turbine as well, is steeper when viewed on a kg/m^2 basis (as in Figure 27)—reflecting the shift towards turbines with lower specific power ratings (W/m^2) over time.

Although these measures of mass intensity and comparisons across turbines are not perfect (e.g., as noted in the text box later in this section, these comparisons would ideally be made only across turbines with the same International Electrotechnical Commission (IEC) class rating), the general reduction in mass intensity over time nevertheless suggests that Vestas, and likely other turbine manufacturers, has managed to avoid scaling penalties through design innovation (and

[35] Steel and cast iron are combined in Figure 26 and Figure 27 to smooth the overall trend in ferrous metals, given that the NEG Micon mass data characterizes certain components as being made of steel rather than cast iron (as specified in all other LCAs). Also note that the mass data from NEG Micon and Nordex (used in the pre-2006 period) did not include data for aluminum, which typically accounts for ~1%–2% of total turbine mass (Table 30 provides the breakdown of raw materials usage for each LCA turbine shown in Figure 26 and Figure 27). Finally, the mass data used for this analysis pertains only to the nacelle, rotor, and tower; foundations and other plant-level cabling or infrastructure are excluded because they are not typically included in the wind turbine prices shown in Figure 21 (which we are attempting to replicate).

perhaps also switching to lighter materials, though that is not readily evident within the LCAs examined here).

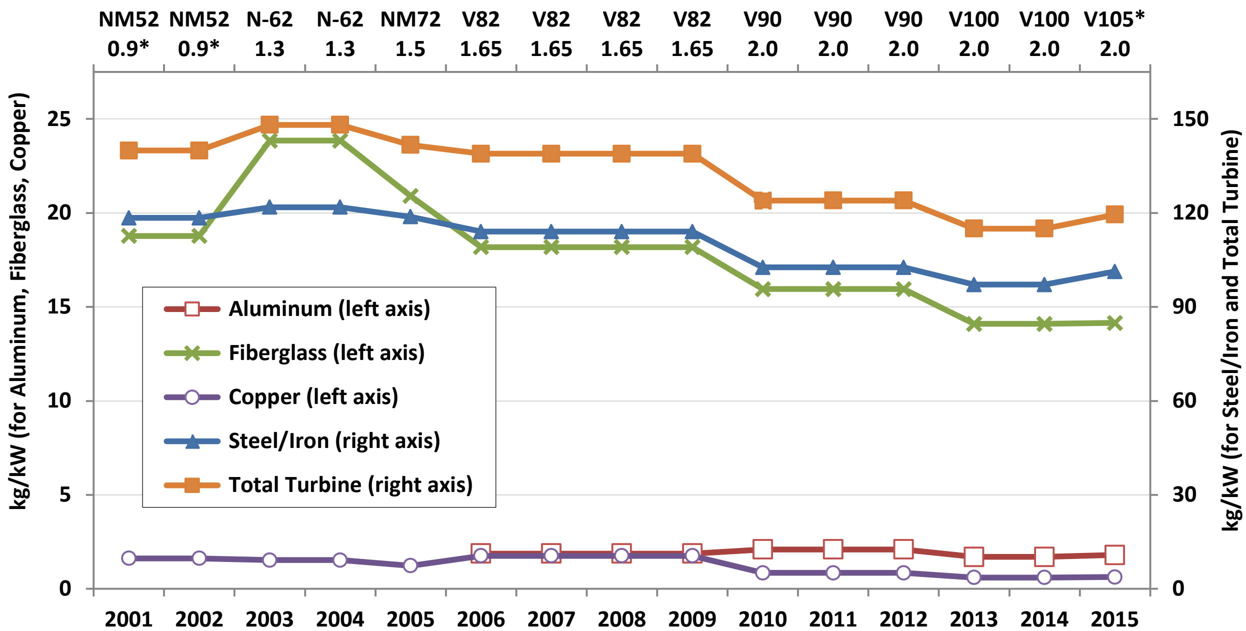


Figure 26. Mass intensity of mapped LCAs (kg/kW)

Sources: Liberman (2003); Vestas (2006); Garrett and Ronde (2011); Razdan and Garrett (2015a, 2015b)

*See footnote 25 regarding averaging of LCA data in 2001, 2002, and 2015

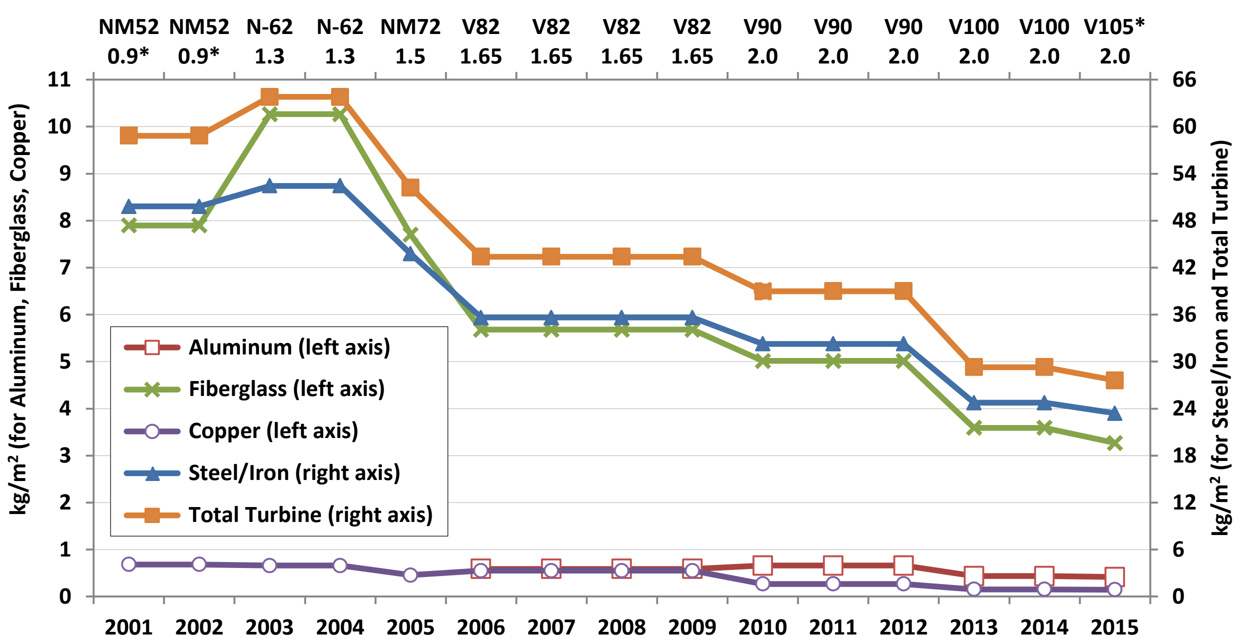


Figure 27. Mass intensity of mapped LCAs (kg/m^2)

Sources: Liberman (2003); Vestas (2006); Garrett and Ronde (2011); Razdan and Garrett (2015a, 2015b)

*See footnote 25 regarding averaging of LCA data in 2001, 2002, and 2015

A More Accurate Comparison of Mass Intensity

Though most directly relevant to the end goal of measuring scaling impacts on a $/kW basis (given that many materials are priced in $/kg terms), expressing mass intensity in kg/kW terms (as in Figure 26) may be somewhat misleading on its own, given that turbines with the same nameplate capacity rating can have different rotor diameters, hub heights, and IEC class ratings—all of which can influence turbine mass and, perhaps more importantly, annual energy production. Similarly, expressing mass intensity in kg/m^2 terms (as in Figure 27) is also not ideal given that turbines with the same rotor diameter can have different nameplate capacity ratings, hub heights, and IEC class ratings—again, all of which can influence turbine mass and annual energy production.

Ultimately, it is ideal to control as many of these variables as possible—IEC class, nameplate capacity, rotor diameter, and/or hub height—when comparing the mass intensity of one turbine to another. Unfortunately, the nature of Figures 26 and 27 (i.e., measuring change in turbine scaling over many years) and a mix of IEC classes among the turbines examined (e.g., the various Vestas turbines in Figures 26 and 27 are rated Class IIA, IIB, and IIIA) prevent a carefully controlled comparison of mass intensity over time.

In contrast, Table 29 focuses on just two of the Vestas turbines featured in Figures 26 and 27, which ostensibly differ only in the size of their rotors. This lone disparity results in a capacity factor difference of 7.5 percentage points. Although both turbines have (rather amazingly) the same mass intensity when measured in kg/kW terms, the mass intensity declines by 33% on a kg/m^2 basis and by 17% on a kg/MWh basis as the rotor increases from 90 to 110. This controlled comparison suggests that turbine manufacturers are indeed finding ways to beat conventional scaling curves.

Table 29. Mass Intensity of Two Vestas 2-MW Class IIIA Turbines

Year of Vestas LCA	2011	2015
Turbine model studied	V90 2.0	V110 2.0
Rotor diameter	90 m	110 m
Nameplate capacity	2.0 MW	
Hub height	80 m	
IEC turbine class	Class IIIA	
Assessed wind speed	7 m/s	
Turbine mass	248,000 kg	
Performance:		
MWh/year	6,257	7,567
Capacity factor	35.7%	43.2%
Mass Intensity:		
kg/kW	124.0	124.0
kg/m^2 swept area	39.0	26.1
kg/MWh	39.6	32.8

Source: Garrett and Ronde (2011); Razdan and Garrett (2015a)

Finally, Figure 28 shows how the changes in the mass of the turbine materials provided in Figure 26 translate into annual and cumulative $/kW turbine cost impacts.[36] As shown, this LCA empirical mass-based approach suggests that scaling has had a minimal (and negative, to boot) effect on turbine prices over the entire period of study. This conclusion stands in direct contrast to the findings of Bolinger and Wiser (2011, 2012), who—having relied on NREL's (2006) CSM—found turbine scaling to be the single largest driver of turbine price increases through 2008 "by a significant margin." Future work should investigate the causes of this discrepancy between the NREL (2006) CSM used in Bolinger and Wiser (2011, 2012) and the LCA mass-based approach adopted here.

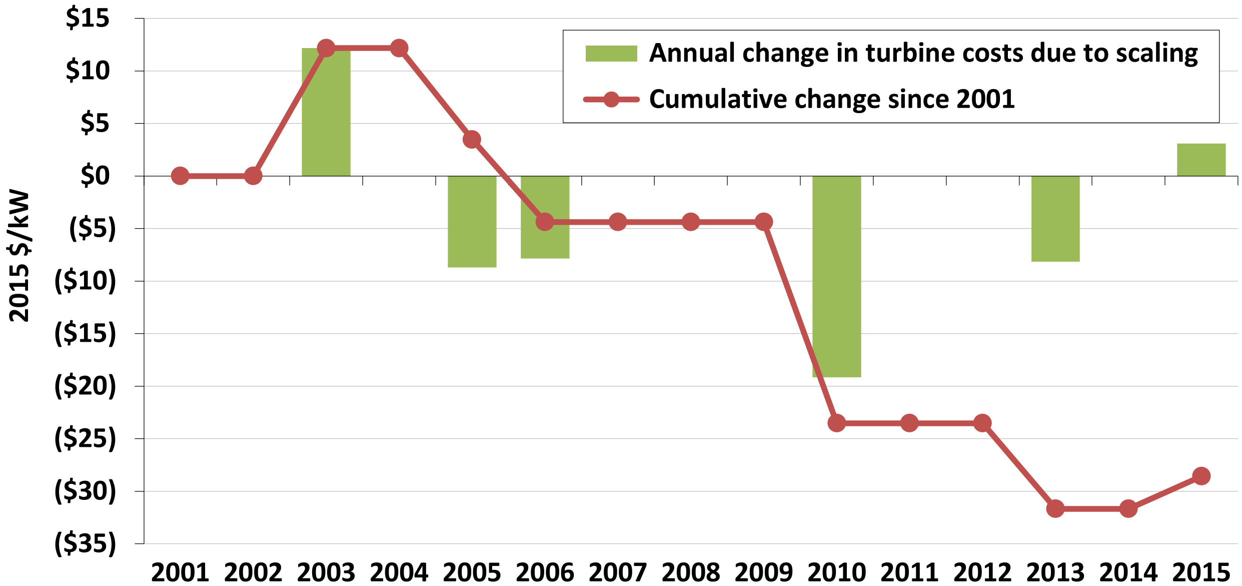


Figure 28. Impact of scaling on wind turbine costs

7.3 Exogenous Drivers

In addition to the four endogenous drivers of wind turbine prices explored in Section 7.2, there are also three exogenous drivers that, although they can be managed to some extent, are nevertheless largely out of the direct control of the wind energy industry. These drivers include changes in raw materials prices, energy prices, and foreign exchange rates—which are analyzed in the following sections.

7.3.1 Raw Materials Prices

Although they are complex machines, wind turbines are manufactured primarily from just five basic raw materials: steel, cast iron, fiberglass (and related composite materials), copper, and aluminum. Table 30 shows that these five materials account for more than 98% of the total mass of a typical wind turbine. Changes in the price of any of these raw materials—but particularly steel, given its predominance—can impact wind turbine prices.[37] Just as in Bolinger and Wiser

[36] Materials pricing from 2015 was used for this purpose for all LCA data.

[37] There is a distinction between the price of raw materials (e.g., steel) and the finished goods made from those materials (e.g., wind turbine towers). Finished goods may cost quite a bit more than the cost of the underlying materials alone would suggest. But if we assume that the size of this "manufacturing premium" (i.e., the margin that manufacturers earn from transforming a raw material into a useful product) does not vary considerably over time (or

(2011, 2012), we used the mass data from the Vestas V82 1.65 MW LCA to measure the effects of changes to raw materials prices. Although using any of the other turbines shown in Table 30 would likely yield similar results, the V82 falls roughly in the middle of the range of masses represented.

Table 30. Condensed Bill of Materials for Wind Turbines Used in Analysis

	OEM						
Turbine make	**Micon**	**Nordex**	**Micon**	**Vestas**	**Vestas**	**Vestas**	**Vestas**
Turbine model	NM52	N-62	NM72	V82 1.65	V90 2.0	V100 2.0	V110 2.0
Nameplate capacity	0.9 MW	1.3 MW	1.5 MW	1.65 MW	2.0 MW	2.0 MW	2.0 MW
Hub height	60.7 m*	69 m	80 m	78 m	80 m	80 m	80 m
Rotor diameter	52.2 m	62 m	72 m	82 m	90 m	100 m	110 m
	Mass (kg per kW)						
Steel	111.2	104.5	110.1	96.3	82.2	83.9	92.2
Fiberglass/resin/plastic	18.8	23.8	20.9	18.2	16.0	14.1	14.2
Iron/cast iron	7.2	17.3	8.7	17.8	20.5	13.3	13.3
Copper	1.6	1.5	1.2	1.8	0.9	0.6	0.7
Aluminum	N/A	N/A	N/A	1.9	2.1	1.7	1.9
Total	**139.9**	**148.2**	**141.7**	**138.9**	**124.0**	**115.0**	**124.0**
	% of Total Turbine Mass						
Steel	79%	71%	78%	69%	66%	73%	74%
Fiberglass/resin/plastic	13%	16%	15%	13%	13%	12%	11%
Iron/cast iron	5%	12%	6%	13%	17%	12%	11%
Copper	1%	1%	1%	1%	1%	1%	1%
Aluminum	N/A	N/A	N/A	1%	2%	1%	2%
Total	**99.2%**	**99.4%**	**99.4%**	**97.8%**	**98.0%**	**98.7%**	**98.5%**

Sources: Liberman (2003); Vestas (2006); Garrett and Ronde (2011); Razdan and Garrett (2015a, 2015b)

Figure 29 shows the cumulative change in real prices for these five raw materials since 2001. Amidst quite a bit of volatility, prices generally rose through mid-2008 and have fallen since early 2011 (with a rapid plunge and recovery cycle in the interim). Given that steel makes up ~70% of the mass in a wind turbine, its price movement dominates the others; though not shown, a mass-weighted composite of these five materials very closely tracks the steel price change shown in Figure 29.

if we account for that margin separately, as we have tried to do in Section 7.2.3), then it is primarily the change in raw materials prices that are of concern when attempting to explain what has driven changes in wind turbine prices.

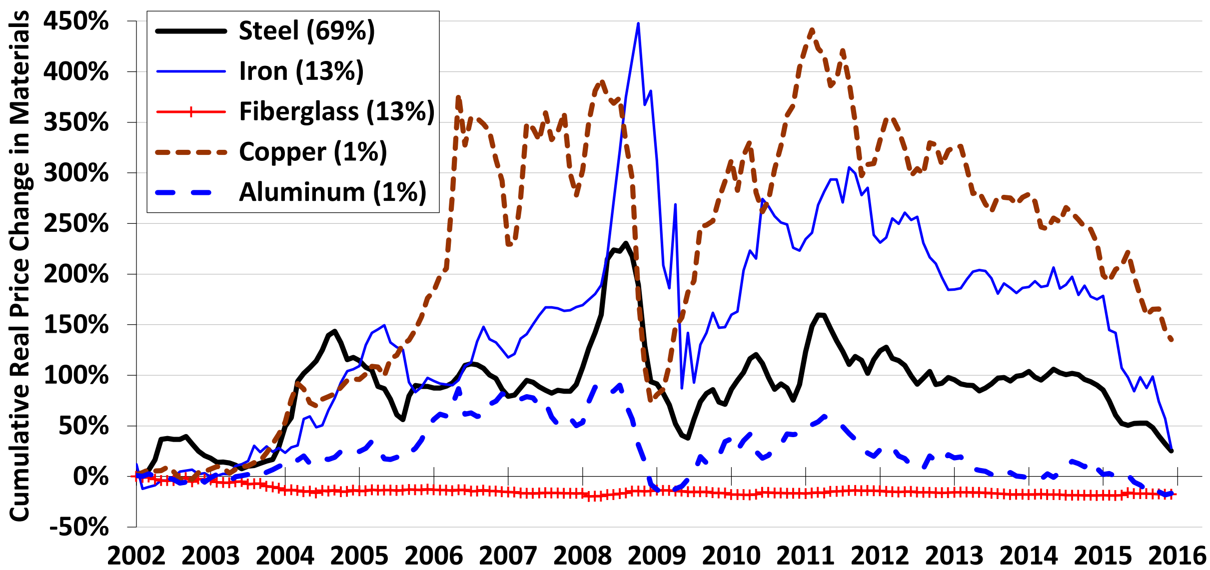


Figure 29. Cumulative change in raw materials prices

Sources: LME (undated); CRUspi (undated); BLS (2016); steelonthenet.com (undated)

Figure 30 shows the resulting impact of these material price changes on wind turbine prices. Commodities prices pushed turbine prices roughly $80/kW higher from 2001 through 2008. Since 2011, pricing pressure has declined by more than $40/kW as the commodity cycle continues to search for a bottom.

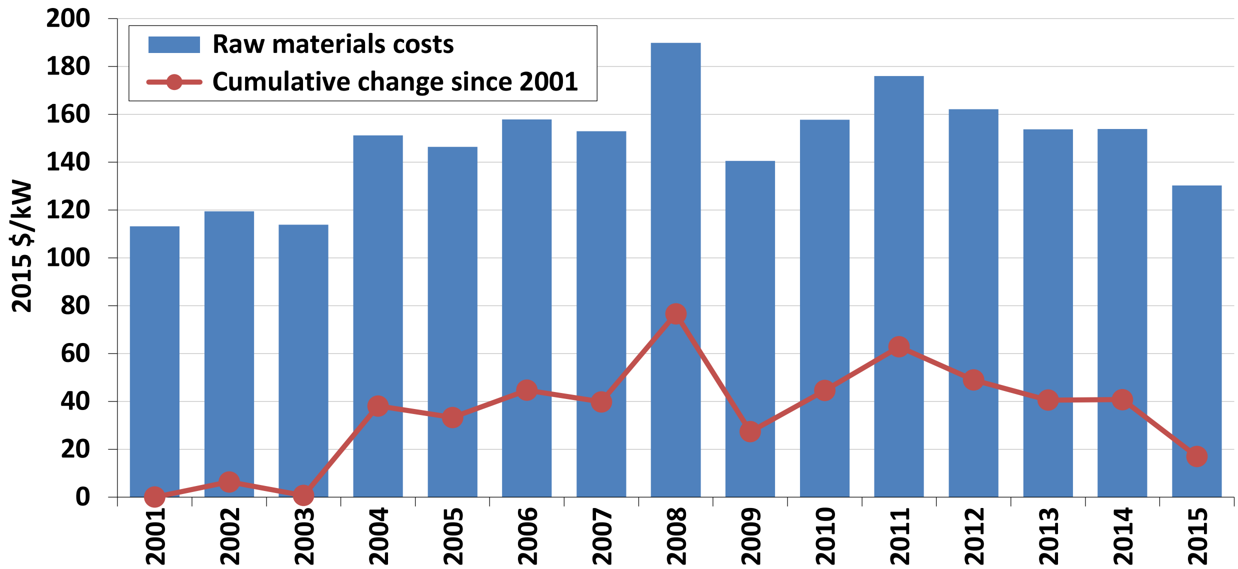


Figure 30. Raw materials costs

7.3.2 Energy Prices

It takes a significant amount of energy to manufacture a wind turbine and transport it—often over long distances—to a project site. As such, changes in the cost of energy used during the manufacture and transportation phases of a wind turbine's life could, therefore, have an impact on wind turbine prices. As discussed in Section 7.6.1, Vestas' LCA of its V82 1.65 MW turbine (Vestas 2006) is also the principal source used here for the amount of primary energy consumed during the manufacture and transport of a wind turbine. Bolinger and Wiser (2011) describe in detail several transformations that are required—including parsing total energy consumption by life cycle phase and then subtracting the embodied energy in the raw materials used to construct the wind turbine during the manufacturing phase—to render the energy consumption data in usable form. For more detail, see Bolinger and Wiser (2011).

Based on the rationale included in Bolinger and Wiser (2011, 2012), we assumed that 60% of the primary energy used to manufacture and transport a wind turbine comes from natural gas, coal, and diesel fuel (in equal 20% proportions), with the remaining 40% coming from stable-priced energy sources (e.g., nuclear and renewables) that are not subject to fuel price risk. Figure 31 shows the cumulative price change since 2001 in these three fossil fuels. Not surprisingly, the overall pattern resembles the earlier graph of commodity price movements—i.e., a general (though volatile) increase through 2008, followed by steady-to-declining (though still volatile) pricing thereafter.

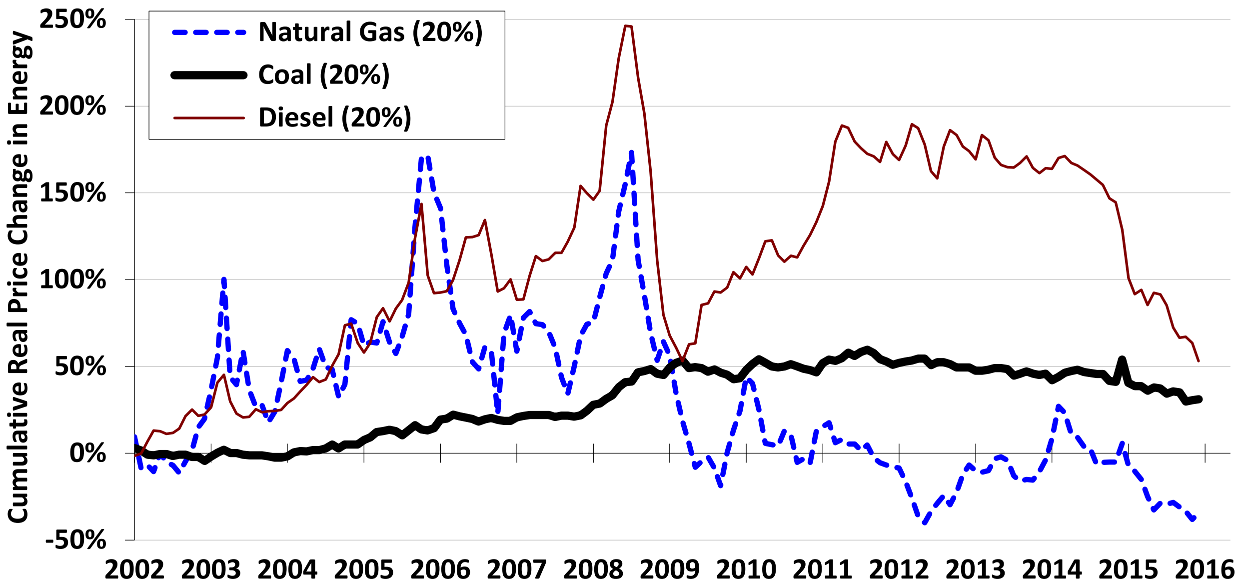


Figure 31. Cumulative change in energy input costs

Source: Energy Information Administration (undated)

Figure 32 tallies up the resulting cost of energy required to make a wind turbine (in 2015 $/kW terms), as well as the cumulative change in those costs since 2001. As shown, the impact of changes to energy prices has been rather minimal: a $13/kW increase through 2008, followed by an $11/kW decline thereafter, leaving energy costs essentially back at 2001 levels.

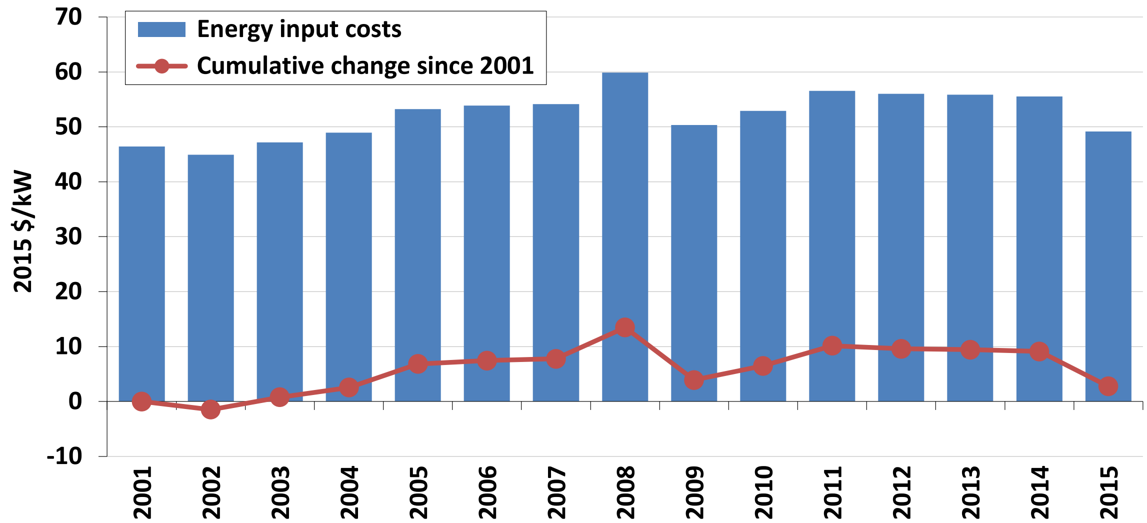


Figure 32. Energy input costs

7.3.3 Foreign Exchange Rates

To measure the impact of movements in foreign exchange rates on wind turbine prices in the United States, this section largely follows the approach provided by Bolinger and Wiser (2011, 2012). The first column in Table 31 ("Import Fraction") shows revised estimates of the percentage of U.S. wind turbine prices that are exposed to the foreign exchange rate risk each year.[38] The remainder of the table compiles data from the International Trade Commission to estimate from which countries those wind turbine imports are arriving. The Euro zone (plus Denmark) and China have been the largest exporters of wind turbine equipment into the United States in recent years, followed by Brazil, Mexico, and Canada.

Table 31. Overall Wind Turbine Import Fraction and Breakdown of Countries of Origin

	Import Fraction	Euro Zone (EUR)	Denmark (DKK)	Japan (JPY)	China (CNY)	India (INR)	U.K. (GBP)	Brazil (BRL)	Mexico (MXN)	Canada (CAD)	Korea (KRW)	Other
2002	**75.0%**	0.0%	72.8%	6.0%	0.0%	0.9%	0.0%	0.0%	17.3%	1.8%	0.1%	1.1%
2003	**73.3%**	10.2%	54.9%	21.6%	0.1%	4.0%	0.0%	0.0%	3.6%	0.8%	4.6%	0.2%
2004	**71.7%**	0.7%	36.6%	23.5%	0.2%	0.0%	2.9%	0.0%	4.6%	21.7%	9.5%	0.3%
2005	**70.0%**	8.5%	62.1%	10.8%	0.3%	2.2%	4.0%	0.0%	2.0%	3.3%	1.7%	5.1%
2006	**68.8%**	18.6%	49.0%	6.7%	1.2%	15.2%	2.8%	0.0%	1.2%	0.8%	1.2%	3.3%
2007	**67.5%**	24.3%	37.1%	10.5%	5.0%	9.4%	4.6%	0.0%	1.4%	2.0%	2.6%	3.1%
2008	**66.3%**	30.5%	22.0%	11.1%	5.8%	5.9%	4.1%	0.0%	1.7%	4.3%	6.0%	8.5%
2009	**65.0%**	19.1%	28.1%	20.3%	5.9%	9.8%	4.3%	0.0%	1.5%	1.1%	5.3%	4.6%
2010	**63.3%**	8.7%	42.0%	0.7%	5.9%	16.3%	0.1%	0.1%	5.6%	8.4%	2.1%	10.0%
2011	**61.7%**	30.1%	40.7%	0.0%	13.3%	0.8%	0.1%	0.0%	2.0%	3.1%	3.8%	6.3%
2012	**60.0%**	17.5%	14.7%	5.7%	21.5%	5.3%	0.1%	14.1%	3.2%	4.4%	4.8%	8.8%
2013	**60.0%**	9.7%	3.1%	9.2%	13.8%	0.3%	0.6%	30.5%	1.9%	6.0%	9.8%	15.0%
2014	**60.0%**	23.2%	11.3%	4.7%	19.0%	1.1%	0.4%	13.9%	3.8%	1.8%	8.2%	12.5%
2015	**60.0%**	28.4%	8.3%	2.2%	24.8%	0.3%	0.3%	9.6%	6.9%	5.8%	1.8%	11.6%

[38] These revised estimates, which show the import fraction declining from 75% in 2002 to 65% in 2009 and 60% by 2012, are based on the Lawrence Berkeley National Laboratory's improved understanding of wind turbine import data published by the International Trade Commission, as well as additional analysis conducted for the lab by GLWN (Weston et al. 2013) since Bolinger and Wiser (2011) was originally published.

Figure 33 shows the cumulative percentage change in the value of the U.S. dollar since 2001 against the currencies of each of the 10 countries listed in Table 31. In addition, the solid black line shows a trade-weighted (based on the average of country exposures in 2014 and 2015) U.S. dollar index. With one exception, Mexico, the U.S. dollar weakened against all of the other nine currencies through 2008, thereby contributing to the increase of dollar-denominated cost of wind turbines and turbine components imported into the United States over that period. Since 2008, the dollar has largely maintained its value and in some cases appreciated considerably. With ~60% of the dollar-denominated price of a wind turbine still estimated to be subject to exchange rate risk, this recent dollar strength has been an enabler of lower dollar-based turbine prices in the United States.

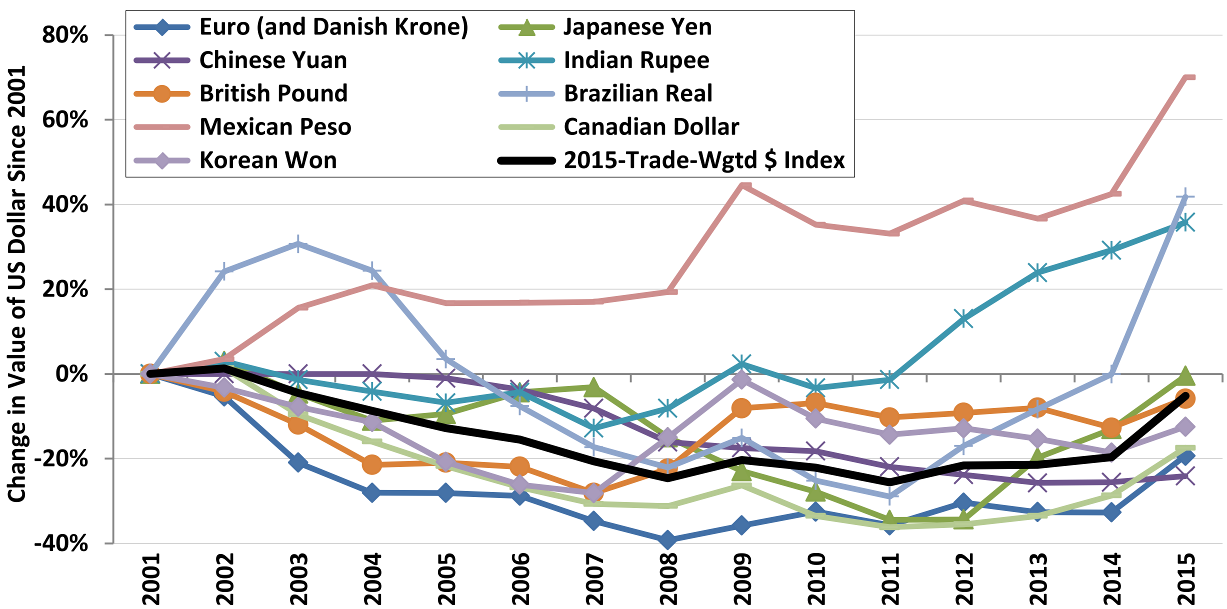


Figure 33. Cumulative change in the value of the U.S. dollar since 2001
Source: federalreserve.gov H.10 release (undated)

Bolinger and Wiser (2011) discussed the concept of "exchange rate pass-through," which is simply the degree to which firms (in this case, turbine manufacturers and their component suppliers) experience and pass along the dollar impact of both favorable and adverse exchange rate movements to their customers. Following a literature review on the topic, Bolinger and Wiser (2011, 2012) assumed a somewhat conservative 50% exchange rate pass-through. In this updated analysis, we instead estimate $/kW turbine price impacts over a range extending from 50% to 100% exchange rate pass-through. As shown in Figure 34, whether pass-through is assumed to be 50% or 100% (or somewhere in between), exchange rate movements have seemingly been a significant contributor to both the increase in dollar-denominated turbine prices from 2001 through 2008 as well as the decline ever since.

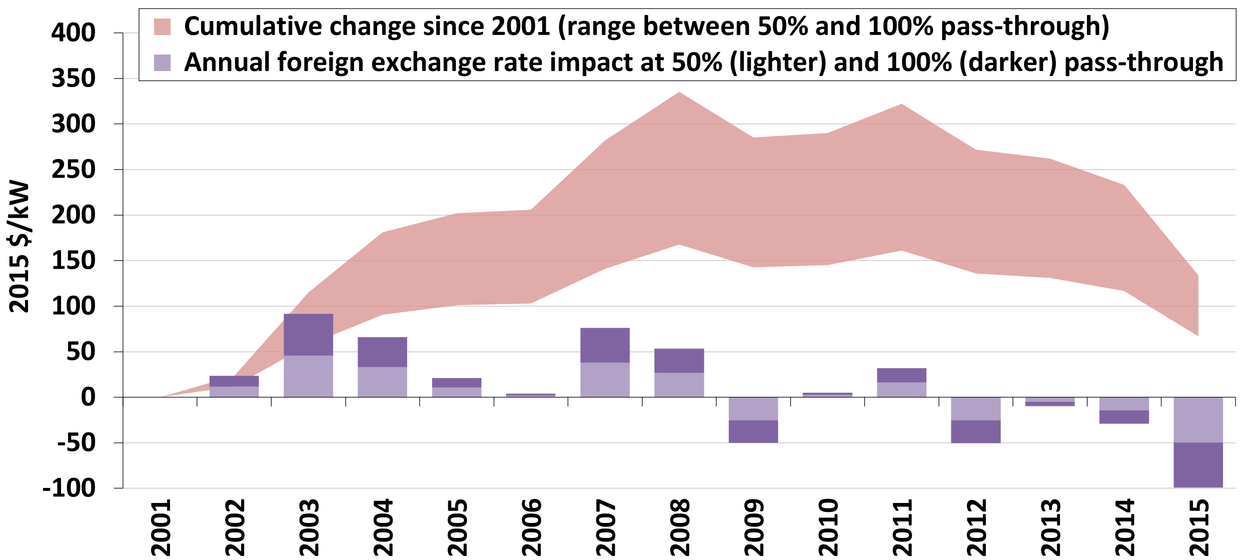


Figure 34. Annual and cumulative foreign exchange rate impacts on wind turbine prices

7.4 Bringing It All Together

Figure 35 depicts a stylized version of observed empirical turbine prices from 2001 to 2015 (gray shaded area, with the range around the central estimate—which is based on Figure 21—reflecting +/- 5% uncertainty), along with the combined results of all seven turbine price drivers (purple shaded area, with a range reflecting a 50%–100% exchange rate pass-through). Table 32 supplements Figure 35 by compiling and aggregating the individual numerical ($/kW) effects of each turbine price driver (as well as subdrivers—e.g., individual commodities) during the increase in turbine prices through 2008 as well as the decline since then. The final column of Table 32 also shows results from one possible scenario discussed later.

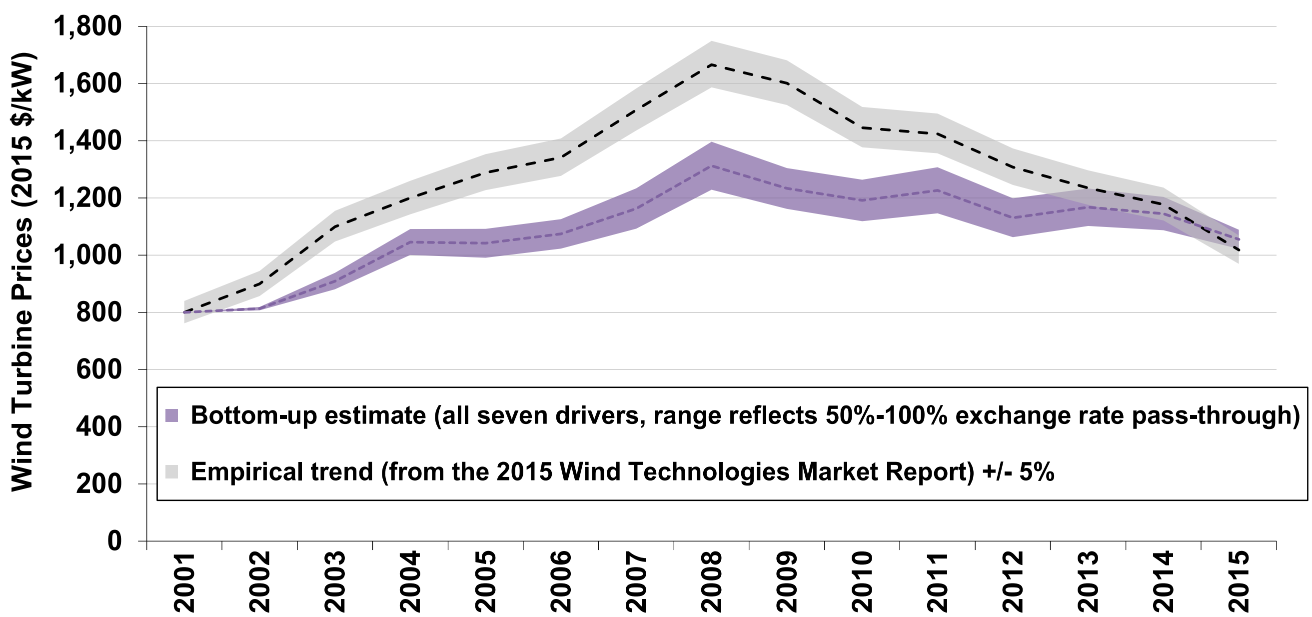


Figure 35. Composite results of analysis versus observed empirical trend

Table 32. Cumulative Impact During Period of Turbine Price Increase (2001–2008) and Decrease (2008–2015)

	2001–2008 (2015 $/kW)	2008–2015 (2015 $/kW)	Possible Scenario (2015 $/kW)
Endogenous Drivers	**+171**	**-36**	**0**
Labor Costs	+79	-4	+16
Warranty Provisions	+37	-34	0
Profit Margins	+60	+26	-16
Turbine Scaling	-4	-24	0
Exogenous Drivers	**+258 to +425**	**-171 to -272**	**+124 to +200**
Materials Prices	+77	-60	+40
Steel	*+69*	*-48*	*+31*
Iron	*+7*	*-5*	*+2*
Copper	*+10*	*-4*	*+5*
Aluminum	*+2*	*-2*	*+5*
Fiberglass	*-12*	*0*	*0*
Energy Prices	+13	-11	+8
Diesel	*+11*	*-7*	*+6*
Coal	*0*	*0*	*+1*
Natural Gas	*+2*	*-4*	*+1*
Currency Movements	+168 to +335	-101 to -202	+76 to +153
Total Impact	**+429 to +597**	**-207 to -308**	**+124 to +200**

Figure 35 reveals that, at least directionally, the simple model developed by Bolinger and Wiser (2011, 2012) and revised and updated here has tracked wind turbine prices in the United States reasonably well. In terms of magnitude,[39] however, the model has underpredicted wind turbine price movements during both the period of increase (through 2008) and decrease (since 2008). One possible explanation is that despite trying to account for expanding profit margins during the increase in turbine prices through 2008, this model may not have adequately captured any "extra-normal" profits that may have been earned during that period—and therefore did not reflect the eventual return to more normal profitability on the flip side either. Such an omission could potentially be attributed to Vestas' profitability not being entirely representative of the profitability of other turbine manufacturers (e.g., GE, which regularly accounts for the largest share of the U.S. market) at the time. In addition, as discussed in Bolinger and Wiser (2011, 2012), this simple model does not account for the profitability of turbine component suppliers, which also likely increased during the rise in turbine prices through 2008 and declined somewhat thereafter. Though Bolinger and Wiser (2011) note several reasons why it is difficult to capture component supplier profitability (e.g., few are publicly traded or are focused solely on wind turbine components, difficulties in deriving $/kW metrics), future work could nevertheless explore what is possible in this area.

Table 32 reveals that the four endogenous drivers have had a much smaller impact than the three exogenous drivers on both the increase and subsequent decline in turbine prices through 2015. In

[39] Figure 35, and indeed many of the figures throughout this section, rather presumptively takes 2001 as a starting point, thereby assuming that wind turbine prices were more or less "correct" or in equilibrium in 2001. Because we are most interested in measuring changes to wind turbine prices over time, the chosen starting point is not particularly important. When considering overall wind turbine price levels, however, the starting point matters more.

particular, turbine scaling has seemingly had a small negative impact on wind turbine prices (in $/kW terms) over both periods; if true, this is a revelation that contradicts earlier work in this area (Bolinger and Wiser 2011, 2012). At least at Vestas, warranty provisions have more or less returned to 2001 levels, suggesting that this recent source of downward price pressure may be largely tapped out. In contrast, profitability at Vestas (and elsewhere) has increased in recent years despite falling turbine prices, suggesting that there could now be some space that enables manufacturers to potentially absorb some portion of any future cost increases (at the expense of profit margins) rather than passing them along to customers through higher turbine prices.

Among the three exogenous drivers, currency movements have had by far the largest impact, even if assuming only a 50% pass-through, followed by raw materials prices (particularly steel prices) and energy prices. The deflationary effect of these three drivers in aggregate since 2008 is roughly two-thirds as large as their prior inflationary effect through 2008, suggesting that there could still be further room to run on the downside. On the other hand, commodity prices have been weak and the dollar strong for a number of years now, and there are those who suggest that we may be nearing the bottom of a "commodity super-cycle" (Cembalest 2016). If true, and the price of steel begins to rise, the increasing focus on concrete towers as a means of reaching ever-higher hub heights may prove to be serendipitous as a materials diversifier as well.[40]

Finally, the last column of Table 32 shows results from one potential future scenario that is loosely based on where the largest risks would seem to lie at present. For example, given where we currently are in the commodity cycle and how low prices have dropped, the balance of commodity price risk would seem to be on the up side, and so the scenario shown in the final column of Table 32 increases commodity prices (for both materials and energy across the board) by 50%—i.e., a rather modest increase compared to the historical price movements shown in Figure 29 and Figure 31. Similarly, the U.S. dollar has enjoyed a prolonged period of strength, perhaps increasing the likelihood that future weakness can be expected; as a result, the scenario shown in Table 32 reflects a 20% weakening of the dollar across the board (which is within the historical bounds shown in Figure 33). Among the endogenous variables, warranty provisions are left unchanged given that there would seem to be little room for further improvements. Scaling impacts are also pegged at zero given both the uncertainty discussed earlier over the true impacts of scaling, as well as the possibility that even if $/kW turbine costs have indeed dropped as turbines have grown larger (as found in this analysis), it may be increasingly difficult to maintain that progress going forward as size continues to increase. Finally, labor costs are assumed to increase by 10% (to reflect emerging upward pressure on wages and, more generally, the inflationary impacts of loose monetary policy coupled with higher commodity prices), but that impact is assumed to be entirely absorbed by a voluntary reduction in profitability ($16/kW roughly corresponds to a 1-percentage-point decline in EBITDA margin, from ~15% to ~14%). The net result is no change among the endogenous drivers in aggregate, compared to a +$124/kW to +$200/kW increase driven by the three exogenous variables in combination (with the range reflecting 50% to 100% exchange rate pass-through). Though not shown in Table 32, perhaps another $50–$60/kW of that increase could be offset through a further reduction in profitability, without leaving EBITDA margins unusually low by historical standards.

[40] Future work could explore the relative economics of steel and concrete towers under a variety of financial scenarios to get a better sense of the degree to which concrete is actually a viable substitute for steel in wind turbine towers.

The scenario presented above is, of course, just one of many different directions in which the market could move. When thinking about the seven turbine price drivers examined, however, it is nevertheless harder to imagine an "opposite" scenario in which these seven drivers push turbine prices lower by \$124/kW to \$200/kW. Fortunately, turbine cost is not the only driver of the levelized cost of wind energy, and the post-2008 period has not only been about reducing the cost of wind turbines, but making them more productive. In particular, reductions in turbine "specific power," which is achieved by increasing the size of the rotor relative to the capacity of the generator, have driven capacity factors sharply higher. Coupled with the decline in turbine prices, this increase in capacity factor has driven the price of wind energy, as revealed by long-term PPAs, to new all-time lows (Wiser and Bolinger 2016). As turbines continue to gain efficiencies through scale (at least in generation, and perhaps also in O&M), further progress in \$/MWh terms is possible—even if turbine prices do not continue to decline much on a \$/MW basis.

8 Conclusions

The analysis and findings in this technical report have resulted in the following conclusions:

- LCOE estimates continue to show a downward trend from the *2010 Cost of Wind Energy Review* (Tegen et al. 2012) to 2015. Offshore costs have shown similar cost reduction trends; however, the decrease in LCOE for land-based projects can be attributed more to the turbine technology, whereas the decrease in offshore LCOE can be attributed more to reductions in BOS costs.
- The reference project LCOE for land-based installations was observed to be $61/MWh; the full range of single-variable, land-based sensitivity estimates covers $48–$108/MWh.
- The reference offshore LCOE project estimates are $181/MWh for fixed-bottom substructures and $229/MWh for floating substructures, with a single-variable sensitivity range of $152–$285/MWh. This range is mostly caused by the large variation in capital expenditures ($3,590–$8,594/kW) reported by project developers and is in part a function of differences in water depth and distance to shore. Although offshore wind cost reductions were relatively modest through 2015, more recent European project bids or "strike prices" suggest that costs for offshore wind could fall precipitously in the coming years.
- The sensitivity analysis shows that LCOE can vary widely based on changes in any one of several key factors; however, the variable with the largest effect on LCOE is CapEx, which is the case for both land-based and offshore projects.
- Regional variation in LCOE based on pairing wind turbine technology with wind resource conditions results in a range of LCOE from $39/MWh to $241/MWh, with estimated LCOE for projects installed in 2015 tending toward the lower end of this range, with estimated LCOE values from $50/MWh to $111/MWh.
- The three exogenous drivers of turbine prices—led by foreign exchange rate movements and followed by materials prices (and steel prices in particular) and energy prices—have had a relatively larger impact on turbine prices than the four endogenous drivers (e.g., labor costs, warranty provisions, profit margins, and turbine scaling), both leading up to and since the 2008 peak in wind turbine pricing.
- The relative influence of the exogenous drivers suggests that any shift away from current macroeconomic conditions, characterized by a prolonged period of dollar strength and commodity price weakness, may create some challenges for further turbine price reductions, absent changes in technology or manufacturing processes that could reduce the material types and input quantities for wind turbines.

This analysis presents a picture of the levelized cost of land-based and offshore wind energy using empirically derived and modeled data that represent 2015 market conditions. Scenario planning and modeling activities often focus on one number (or cost) for land-based LCOE and one for offshore LCOE. In reality, the cost of land-based wind energy varies greatly across the United States and offshore wind LCOE varies significantly across Europe and Asia (Table 33).

Notably, the LCOE analysis presented in this report is only one way to measure the cost of wind energy. It does not include other costs and price issues that influence a given wind project's viability, such as transmission, environmental impacts, military constraints, or other areas of consideration (e.g., public policy, consumer costs, energy prices, or public acceptance). In addition, these LCOE estimates do not reflect the value of electricity, incentives, or other policy mechanisms (such as PTCs or ITCs) that affect the sales price of electricity produced from wind projects.

Table 33. Range of LCOE for U.S. Land-Based and Offshore Wind in 2015

	Land-Based Wind Projects	Offshore Wind Projects
CapEx	$1,360–$3,460/kW	$3,590–$8,594/kW
OpEx	$4–$30/MWh	$19–$56/MWh
Capacity factor	28.5%–49.5%	35%–52%
Discount rate	5.5%–11.0%	6.0%–7.0%
Operational life	20–30 years	20–30 years
Range of LCOE	**<$48–>$108/MWh**	**<$133–>$285/MWh**

9 Related and Future Work

NREL continues to work to gain a better understanding of costs associated with many components of wind turbines and systems. Ongoing collaboration with industry, growing datasets, and enhanced modeling capabilities are expected to continue to lead to better insights and increased awareness of current and future wind power system component costs.

NREL aims to update this review of wind energy costs on an annual basis. These updates are intended to help maintain a perspective on costs that are grounded in real-time market changes and to offer greater insight into the costs and performance of individual components related to the wind electric generation system. In addition, these reports are intended to provide greater clarity regarding wind energy costs and the effects of changes in specific variables on LCOE. The data and tools developed from this work will be used to help inform projections, goals, and improvement opportunities. As the industry evolves and matures, NREL will continue to publish current representative project data and LCOE estimates for scenario planning, modeling, and goal setting.

Future work entails three primary objectives: (1) continuing to enhance data representing market-based costs, performance, and technology trends to reflect actual wind industry experience, (2) enhancing the fidelity of bottom-up cost and performance estimation for individual wind plant components, and (3) understanding sensitivities to factors such as regional differences, site characteristics, and technology choices. In 2017 and going forward, NREL will continue to work with industry and national laboratory partners to obtain project-specific data to validate and improve models. More specifically, NREL's ongoing wind analysis efforts include:

- Improving the Offshore Balance of System model to better represent the offshore nonturbine project costs, such as foundations, electrical cabling, and installation, across a range of turbine and project sizes in addition to updating the NREL 2015 CSM turbine cost relationships and cost curves
- Updating WISDEM with additional modules such as the updated NREL 2015 CSM and the Offshore Balance of System model
- Assessing potential cost reduction pathways in support of the new *National Offshore Wind Strategy* (Gilman et al. 2016)
- Investigating the impact of taller towers and the effect on LCOE and national capacity.

In addition, NREL plans to pursue work that could:

- Reduce risk in preconstruction energy estimates
- Result in an enhanced understanding of the wind turbine supply chain for the U.S. market
- Provide new capabilities in computational fluid dynamics models to better determine the magnitude and impact of wake losses
- Quantify the effect of potential technology pathways on system LCOE for land-based and offshore wind technology
- Result in a greater understanding of the effects of the Jones Act on offshore wind in the United States

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Appendix A. Summary of Assumptions for 2015 Reference Projects

Land-Based Wind Project Assumptions

Table A1. Comprehensive List of Assumptions for 2015 Land-Based Reference Project Cost of Energy

Assumption	Units	Value	Notes
Project Information			
Capacity	megawatts (MW)	200	Calculation
Number of turbines	#	100	Representative of commercial-scale projects
Turbine capacity	MW	2.0	Average turbine size installed in United States
Net capacity factor	%	39.9	Wind resource [7.25 meters per second (m/s) at 50 m], assumed losses (17%)
Rotor diameter	meters (m)	102.0	Average rotor size installed in United States
Tower height	m	82.1	Average hub height installed in United States
Operational life	years	20	Standard business case assumption
Capital Expenditures (CapEx)			
CapEx (million)	$	338	Calculation
Capital expenditures (CapEx)	$/kilowatt (kW)	1,690	Average CapEx of 2015 U.S. projects (Wiser and Bolinger 2016)
Hard costs			NREL's wind turbine design Cost and Scaling Model (Fingersh et al. 2006; Maples, Hand, and Musial 2010), NREL's new balance-of-system model, and NREL's conversations with developers of land-based wind projects in the United States
Turbine	$/kW	1,209	
Balance of system	$/kW	330	
Soft costs			
Construction finance	$/kW	49	
Contingency	$/kW	102	
Operational Expenditures (OpEx)			
OpEx costs	$/MWh	14.6	Representative of published literature and NREL's conversations with U.S. land-based wind developers
OpEx costs (pretax)	$/kW/yr	51	
Operation (OPER)	$/kW/yr	15	
Maintenance (MAIN)	$/kW/yr	28	
Land lease	$/kW/yr	8	
Financing Costs [d, Fixed Charge Rate (FCR)]			
Inflation rate	%	2.5	Assumption in *ATB* (NREL 2016)
Discount rate (nominal)	%	8.3	2015 land-based weighted-average cost of capital (WACC) [(Vitina et al. 2015) and updated by Lawrence Berkeley National Laboratory (LBNL) for years 2013–2015]
Discount rate (real)	%	5.7	
FCR (nominal)	%	11.8	Calculation
FCR (real)	%	9.6	
Cost recovery factor (nominal)	%	10.4	
Cost recovery factor (real)	%	8.5	
Taxes (T)			
Effective	%	40.0	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	7.5	Representative state tax rate
Present Value Depreciation (PVdep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr Modified Accelerated Cost Recovery System (MACRS)		Standard choice for wind energy projects
PVdep	%	80.5	Calculation
Levelized cost of energy	**$/MWh**	**61**	**Calculation**

Offshore Wind Project Assumptions

Table A2. Comprehensive List of Assumptions for 2015 Fixed-Bottom Offshore Reference Project Cost of Energy

Assumption	Units	Value	Notes
Project Information			
Capacity	MW	600	Representative of commercial-scale projects
Number of turbines	#	145	Calculation
Turbine capacity	MW	4.14	Average turbine size installed globally
Depth	m	30	Representative of proposed U.S. projects
Distance from shore	kilometers (km)	30	Representative of proposed U.S. projects
Net capacity factor	%	41.2	Wind resource (8.4 m/s at 50 m), losses calculated
Rotor diameter	m	118.9	Average rotor size installed globally
Tower height	m	90.3	Average hub-height size installed globally
Operational life	years	20	Standard business case assumption
Capital Expenditures (CapEx)			
CapEx ($)	$ millions	2,769	Calculation
CapEx	$/kilowatt (kW)	4,615	Empirical model calculation (Beiter et al. 2016)
Hard Costs			Values estimated based on the NREL offshore balance-of-system model (Maness and Maples forthcoming), several recent publications (Douglas-Westwood 2010; BVG Associates 2011; Hamilton et al. 2014; Smith, Stehly, and Musial 2015; Beiter et al. 2016), and NREL's conversations with developers of offshore wind projects in the United States; percentage estimates applied to CapEx estimate to obtain dollar-per-kilowatt values.
Turbine	$/kW	1,466	
Development	$/kW	66	
Engineer and management	$/kW	73	
Substructure and foundation	$/kW	679	
Site access, staging, and port	$/kW	24	
Electrical infrastructure	$/kW	396	
Assembly and installation	$/kW	893	
Plant commissioning	$/kW	36	
Soft Costs			
Insurance during construction	$/kW	46	
Decommissioning bond	$/kW	237	
Construction finance	$/kW	297	
Contingency	$/kW	403	
Operating Expenditures (OpEx)			
OpEx	$/megawatt-hour (MWh)	49.6	Calculation
OpEx costs (pretax)	$/kW/yr	179	
Operations (pretax)	$/kW/yr	40	Representative of published literature and NREL's conversations with U.S. offshore wind developers
Maintenance	$/kW/yr	148	
Outer Continental Shelf (OCS) lease	$/kW/yr	17	Atlantic OCS lease—2% operational revenue in years one–15, 7% of operational revenue in years 15–20
Financing Costs (d, FCR)			
Inflation rate	%	2.5	Assumption in *Annual Technology Baseline* (2016)
Discount rate (nominal)	%	9.13	Approximate WACC for European projects installed in 2016
Discount rate (real)	%	6.47	
FCR (nominal)	%	12.6	Calculation
FCR (real)	%	10.3	
Cost recovery factor (CRF)/nominal	%	11.1	
Cost recovery factor (real)	%	9.1	
Taxes			
Effective	%	40.0	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	7.5	Representative state tax rate

Assumption	Units	Value	Notes
Present Value Depreciation (PVdep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr Modified Accelerated Cost Recovery System		Standard choice for wind energy projects
PVdep	%	78.9	Calculation
Levelized cost of energy	**$/MWh**	**181**	**Calculation**

Table A3. Comprehensive List of Assumptions for the 2015 Floating Offshore Reference Project Cost of Energy

Assumption	Units	Value	Notes
Project Information			
Capacity	MW	600	Representative of commercial-scale projects
Number of turbines	#	145	Calculation
Turbine capacity	MW	4.14	Average turbine size installed globally
Depth	m	30	Representative of proposed U.S. projects
Distance from shore	kilometers (km)	30	Representative of proposed U.S. projects
Net capacity factor	%	41.2	Wind resource (8.4 m/s at 50 m), losses calculated
Rotor diameter	m	118.9	Average rotor size installed globally
Tower height	m	90.3	Average hub-height size installed globally
Operational life	years	20	Standard business-case assumption
Capital Expenditures (CapEx)			
CapEx ($)	$ millions	4,125	Calculation
CapEx	$/kilowatt (kW)	6,647	Empirical model calculation (Beiter et al. 2016)
Hard Costs			Values estimated based on the NREL offshore balance-of-system model (Maness and Maples forthcoming), several recent publications (Douglas-Westwood 2010; BVG Associates 2011; Hamilton et al. 2014; Smith, Stehly, and Musial 2015; Beiter et al. 2016), and NREL's conversations with developers of offshore wind projects in the United States; percentage estimates applied to CapEx estimate to obtain dollar-per-kilowatt values.
Turbine	$/kW	1,466	
Development	$/kW	166	
Engineer and management	$/kW	149	
Substructure and foundation	$/kW	2,404	
Site access, staging, and port	$/kW	40	
Electrical infrastructure	$/kW	695	
Assembly and installation	$/kW	736	
Plant commissioning	$/kW	56	
Soft Costs			
Insurance during construction	$/kW	66	
Decommissioning bond	$/kW	80	
Construction finance	$/kW	427	
Contingency	$/kW	462	
Operating Expenditures (OpEx)			
OpEx	$/megawatt-hour (MWh)	38.4	Calculation
OpEx costs (pretax)	$/kW/yr	138	
Operations (pretax)	$/kW/yr	31	Representative of published literature and NREL's conversations with U.S. offshore wind developers
Maintenance	$/kW/yr	107	
Outer Continental Shelf (OCS) lease	$/kW/yr	17	Atlantic OCS lease—2% operational revenue in years one–15, 7% of operational revenue in years 15–20
Financing Costs (d, FCR)			
Inflation rate	%	2.5	Assumption in *Annual Technology Baseline* (2016)
Discount rate (nominal)	%	9.13	Approximate weighted average cost of capital for European projects installed in 2016
Discount rate (real)	%	6.47	
FCR (nominal)	%	12.6	Calculation
FCR (real)	%	10.3	
Cost recovery factor	%	11.1	

Assumption	Units	Value	Notes
(CRF)/nominal			
Cost recovery factor (real)	%	9.1	
Taxes			
Effective	%	40.0	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	7.5	Representative state tax rate
Present Value Depreciation (PVdep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr Modified Accelerated Cost Recovery System		Standard choice for wind energy projects
PVdep	%	78.9	Calculation
Levelized cost of energy	**$/MWh**	**229**	**Calculation**

Appendix B. Financial Calculations

Levelized Cost of Energy Equation and Financial Assumptions

The equation used to calculate levelized cost of energy (LCOE) is derived from Short et al. (1995) and NREL's *Annual Technology Baseline* as follows[41]:

$$LCOE = \frac{FCR * CAPEX + OPEX}{(\mathrm{AEP_{net}}/1{,}000)} \tag{2}$$

$$FCR = CRF * ProFinFactor \tag{3}$$

$$CRF = \frac{WACC - 1}{1 - \left(\frac{1}{WACC}\right)^{t}} \tag{4}$$

$$WACC = \frac{(1 + [(1 - DF)(RROE * i - 1)] + [DF(IR * i - 1)(1 - TR)])}{i} \tag{5}$$

$$ProFinFactor = \left(\frac{1 - TR * PVD}{1 - TR}\right) \tag{6}$$

$$PVD = \sum_{y=1}^{M+1} FD_y f_y \tag{7}$$

$$f_y = \frac{1}{d^y} \tag{8}$$

$$d = WACC * i \tag{9}$$

$$CAPEX = ConFinFactor * (OCC * CapRegMult + GCC) \tag{10}$$

$$ConFinFactor = \sum_{y=0}^{C-1} AI_y\, FC_y \tag{11}$$

$$AI_y = 1 + (1 - TR) * (IDC^{y+0.5} - 1) \tag{12}$$

$$GCC = GF + OnSpurCost + OffSpurCost \tag{13}$$

$$OnSpurCost = OnDist \times OnTransCost \times OnRegTransMult \tag{14}$$

$$OffSpurCost = OffDist \times OffDistFactor \tag{15}$$

[41] In the *Annual Technology Baseline*, OpEx is equivalent to fixed operating costs and $\mathrm{AEP_{net}}$ is equivalent to CF*8760 (capacity factor times hours per year).

Table B1. Summary of Annual Technology Baseline-Specific Terms Used in the Regional LCOE Analysis

	Symbol	Name	Definition
Project Finance	*t*	Economic Lifetime (years)	Length of time for paying off assets (20 years for all technologies)
	DF	Debt Fraction	Fraction of capital financed with debt; *1-DF* is assumed financed with equity (50% for all technologies)
	RROE	Rate of Return on Equity (real)	Assumed rate of return on the share of assets financed with equity (10% real/13% nominal for all technologies)
	IR	Interest Rate (real)	Assumed interest rate on debt (5.4% real/8% nominal for all technologies)
	i	Inflation Rate	Assumed inflation rate based on historical data (2.5%)
	TR	Tax Rate	Combined state and federal tax rate (40%)
	M	Depreciation Period (years)	Number of years in the Modified Accelerated Cost Recovery System (MACRS) depreciation schedule (five for wind plants)
	FD	Depreciation Fraction	Fraction of capital depreciated in each year, 1 to *M* (20%, 32%, 19.2%, 11.5%, 11.5%, and 5.76% for wind plants)
	CRF	*Capital Recovery Factor*	*The ratio of a constant annuity to the present value of receiving that annuity for a given length of time (8.89% real/10.9% nominal); CRF is a function of WACC and t*
	WACC	*Weighted-Average Cost of Capital (real)*	*The average expected rate that is paid to finance assets (6.2% real/8.9% nominal); WACC is a function of DF, RROE, IR, i, and TR.*
	ProFinFactor	*Project Finance Factor*	*Technology-specific financial multiplier to account for the taxes and depreciation (1.137); ProFinFactor is a function of TR, WACC, i, M, and FD*
Wind Plant Techno-Economic Cost and Performance Parameters	*OCC*	Overnight Capital Cost ($/MW)	Capital expenditures, excluding construction period financing. Includes on-site electrical equipment and grid connection costs but does not include additional transmission features to reach a high-voltage transmission system.
	CapRegMult	Capital Regional Multiplier	Capital cost multipliers to account for regional variations that affect plant costs; e.g., labor rates
	C	Construction Duration	Number of years in the construction period (3)
	FC	Capital Fraction	Fraction of capital spent in each year of construction (80%, 10%, 10%)
	IDC	Interest During Construction	Interest rate for financing project during the construction period (8%)
	OPEX	Operation and Maintenance Expenses ($/MW-year)	Annual expenditures to operate and maintain equipment that are incurred on a per-unit-capacity basis

	Symbol	Name	Definition
	AEP_{net}	Net Annual Energy Production (MWh/MW/yr)	The amount of energy produced in a given year per MW capacity after system losses and availability are taken into account
	CF_{net}	Net Capacity Factor (%)	Generally defined as the ratio of actual annual output to output at rated capacity for an entire year
	$CAPEX$	Installed Capital Cost	Total capital expenditure to achieve commercial operation up to the plant gate
	$ConFinFactor$	Construction Finance Factor	Portion of CAPEX associated with construction period financing (1.039); ConFinFactor is a function of C, FC, and IDC
Grid Connection Costs	GF	Grid Feature	Point of interconnection at the high-voltage transmission network, including substation, transmission lines, load center, or balancing area center (Default in the ReEDS is $0/kW for substation and load center and $14/kW for others)
	$OnDist$	Onshore Distance	Total onshore distance covered by the onshore transmission spur lines
	$OffDist$	Offshore Distance	Total offshore distance covered by the offshore export cables
	$OnTransCost$	Onshore Transmission Costs (For Spur Line)	Base onshore transmission line costs ($3,922/MW-mile)
	$OffDistFactor$	Offshore Distance Factor	Incremental capital expenditure for offshore wind plant export cable length between landfall and offshore wind plant site and construction-period transit costs between port and offshore wind plant site. Assumed high-voltage alternating current (HVAC) for cables that are less than 70 km and high-voltage direct current (HVDC) otherwise ($8.10/kW-km for AC cables and $13.49/kW-km for DC cables)
	$OnRegTransMult$	Onshore Regional Transmission Multiplier	Transmission cost multipliers to account for regional variations that affect onshore transmission line costs (e.g., labor rates, terrain, and siting)
	GCC	*Grid Connection Costs*	*All costs from the plant gate to the high-voltage transmission network*
	$OnSpurCost$	*Onshore Spur Line Costs*	*Cost for onshore transmission lines from the plant gate to the grid feature; OnSpurCost is a function of OnDist, OnTransCost, and OnRegTransMult*
	$OffSpurCost$	*Offshore (Underwater) Spur Line Costs*	*Cost for offshore (underwater) export cables from the offshore turbines to land, including incremental construction-period transit cost; OffSpurCost is a function of OffDist and OffDistFactor*

Land-Based Wind Financial Assumptions and Calculations

Table B2. LCOE Weighted-Average Cost of Capital (IEA Based) and Present Value of Depreciation Calculations (WACC = 8.3%)

Parameters	Percentage	Nominal Rate	Real Rate
Tax Equity (After-Tax Yield)	60%	7.90%	5.78%
Cash Equity (After-Tax Yield)	40%	8.90%	6.76%
Income Tax			
Federal		35.0%	35.0%
State (6%)		7.7%	7.7%
Composite		40.0%	40.0%
Discount Rate (after tax)		8.3%	5.7%
Present Value Depreciation		80.54%	80.54%
Fixed Charge Rate (FCR)		**11.8%**	**9.6%**

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.47	18.47
2	80	32.00%	32	27.28	45.75
3	48	19.20%	19.2	15.12	60.87
4	28.8	11.52%	11.52	8.37	69.24
5	17.28	11.52%	11.52	7.73	76.97
6	5.76	5.76%	5.76	3.57	80.54

MACRS: Modified Accelerated Cost Recovery System

Offshore Wind Financial Assumptions and Calculations

Table B3. Balance Sheet Scenario and Present Value of Depreciation Calculations (WACC = 8.65%)

Parameters	Percentage	Nominal Rate	Real Rate
Tax Equity (After-Tax Yield)	50%	6.00%	3.92%
Cash Equity (After-Tax Yield)	50%	11.30%	9.12%
Income Tax			
Federal		35.0%	35.0%
State (6%)		7.7%	7.7%
Composite		40.0%	40.0%
Discount Rate (after tax)		8.65%	6.00%
Present Value Depreciation		79.86%	79.86%
Fixed Charge Rate (FCR)		**12.1%**	**9.9%**

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.41	18.41
2	80	32.00%	32	27.11	45.52
3	48	19.20%	19.2	14.97	60.49
4	28.8	11.52%	11.52	8.27	68.75
5	17.28	11.52%	11.52	7.61	76.36
6	5.76	5.76%	5.76	3.50	79.86

MACRS: Modified Accelerated Cost Recovery System

Table B4. Project Finance Scenario and Present Value of Depreciation Calculations (WACC = 9.67%)

Parameters	Percentage	Nominal Rate	Real Rate
Tax Equity (After-Tax Yield)	60%	7.50%	5.39%
Cash Equity (After-Tax Yield)	40%	12.90%	10.69%
Income Tax			
Federal		35.0%	35.0%
State (6%)		7.7%	7.7%
Composite		40.0%	40.0%
Discount Rate (after tax)		9.67%	7.00%
Present Value Depreciation		77.95%	77.95%
Fixed Charge Rate (FCR)		**12.6%**	**10.8%**

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.24	18.24
2	80	32.00%	32	26.61	44.85
3	48	19.20%	19.2	14.56	59.41
4	28.8	11.52%	11.52	7.97	67.37
5	17.28	11.52%	11.52	7.26	74.64
6	5.76	5.76%	5.76	3.31	77.95

MACRS: Modified Accelerated Cost Recovery System

Appendix C. Offshore Methodology Changes

The methodology used to calculate the LCOE for offshore wind projects has been updated. The U.S. Department of Energy *National Offshore Wind Strategy* (Gilman et al. 2016) and *A Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016) detail the current methodology and the changes that were applied. The purpose of this appendix is to describe the evolution and implications of these changes from the *2014 Cost of Wind Energy Review* to this current publication. Table C1 summarizes the various reported costs and associated LCOE changes.

Table C.1. Offshore Cost and LCOE Reported in 2016

	2014 Cost of Wind Energy Review	Offshore Strategy Meeting	Cost Reduction Pathway Report	2015 Cost of Wind Energy Review
Turbine capital cost	**1,952**	**1,694**	**1,471**	**1,466**
Balance of system	**2,277**	**2,826**	**2,632**	**2,406**
Development	292	316	289	199
Substation and foundation	535	727	727	679
Electrical infrastructure	763	1267	1203	396
Assembly and installation	687	516	413	893
Financial costs	**1,084**	**847**	**727**	**914**
Capital expenditures	**5,925**	**5,367**	**4,787**	**4,615**
Operational expenditures	**138**	**177**	**177**	**179**
Fixed charge rate	**9.8%**	**10.5%**	**10.5%**	**10.3%**
LCOE ($/MWh)	**193**	**203**	**185**	**181**

Turbine Capital Costs

The *2014 Cost of Wind Energy Review* based the turbine capital cost from publicly available data, which are outlined in the *2014–2015 Offshore Wind Technologies Market Report* (Smith et al. 2015). The publicly available turbine supply prices were then adjusted using an exchange rate of $1.33/Euro. During the offshore strategy meeting held in December 2015, in Washington, D.C., the methodology was adjusted. Using turbine pricing relationships from BVG (BVG 2011), a curve-fit relationship between turbine rating (megawatts [MW]) and capital expenditures (CapEx) was created. The baseline point used was the same turbine price ($1,952/kilowatt [kW]) in the *2014 Cost of Wind Energy Review* (Moné et al. 2015) and *2014–2015 Offshore Wind Technologies Market Report* (Smith et al. 2015) for a 6-MW turbine rating. *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* report (Beiter et al. 2016) used the same curves, but adjusted the exchange rate to the current $1.11/Euro. The cost reduction pathway report and *2015 Cost of Energy Review* are showing different prices as a result of different turbine ratings (MW) that were used in the analysis.

Balance-of-System Costs

The *2014 Cost of Energy Review* (Moné et al. 2015) calculated the balance-of-system (BOS) costs using the NREL Offshore Balance of System Cost Model (Maness et al. 2016) given the project assumptions detailed in the report. The offshore strategy and cost reduction pathway analyses studied the cost impacts of a range of offshore wind location cost variables for more than 7,000 potential coastal sites in the United States to understand whether offshore wind can achieve significant cost reductions that may allow the technology to reach economic viability over a time frame spanning from 2015 to 2030. The analyses used a geospatial cost model, analytical assumptions for potential cost reduction pathways, and corresponding cost of energy estimates, adjusting for location, regional resource, and time.

Because of this type of analysis, a new internal model was created to estimate the BOS costs. The initial baseline for each BOS category was NREL's Offshore Balance of System Cost Model, in which a number of scenarios were examined using different technologies, locations, and site conditions. These data were then used to create new exponential curve fits. For example, for the cost of construction and operations port and inshore assembly areas, the sensitivities were determined by using the offshore BOS cost model by varying each of the key parameters one at a time for each of the scenarios, which included three turbine sizes with four substructure types for a total of 12 unique scenarios. Cost outputs were then used to develop curve-fit relationships that scale with the key parameter inputs. Cost estimating relationships were divided into three different categories: substructure installation cost, turbine installation cost, and port, staging, and transport costs. The resulting curve fits were then used to build more complex algorithms implemented in the spatial-economic framework that apply various adjustment factors and can recognize inputs like substructure type or turbine size and calculate costs accordingly. A more detailed description of the curve-fitting process and results is provided in Appendix C-2 of *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016).

Regarding specific categories, different percentages of the total CapEx or some portion of the different subcategories were used. For instance, for development, the cost of energy reviews used a combination of the costs for particular factors including permits, studies, and front-end engineering design work to determine the development cost. In the offshore strategy and cost reduction pathways reports, a flat 4% of the total CapEx was used. Additionally, a few smaller categories that are detailed in the cost of energy reviews have been combined into development, such as project management, port and staging, and commissioning.

The methodology used in the substructure and assembly categories for the cost of energy reviews are the same but the water depth was changed between 2014 and 2015, thereby increasing the costs. The curve-fit methodology previously described was used for the offshore strategy and cost reduction pathway studies. The difference in cost between the offshore strategy and the *2015 Cost of Energy Review* is a result of the different turbine rating being used between the two different studies. In other cases, such as the electrical infrastructure category, the NREL Offshore Balance of System Cost Model was used as a baseline but was then supplemented with additional studies such as the *National Offshore Wind Energy Grid Interconnection Study* (Daniel et al. 2014) and The Crown Estate (2012), which cause the costs in these categories to be much higher than in the cost of wind energy review reports. In addition, these reports have the electrical infrastructure assembly cost in the assembly category, whereas the offshore strategy and cost reduction pathway studies have those costs included in the electrical infrastructure category.

A key addition that was made over the past year was to apply a Jones-Act-compliance adder. The Jones Act stipulates that only U.S.-flagged vessels may make trips between two U.S. ports. As a result, a cost factor is needed that accounts for the additional cost, which is foreseen from using only U.S.-flagged vessels that have substantially lower installation capabilities compared to the purpose-built fleet of European turbine installation vessels. Two cost factors were developed that include a 23% adder for 2015. The Jones Act adder affects not only the assembly and installation category but also the operations and maintenance category and is included in the *National Offshore Wind Strategy* (Gilman et al. 2016), *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016), and *2015 Cost of Wind Energy Review* (citation).

The *2014 Cost of Wind Energy Review* (Moné et al. 2015) used data from the U.S Department of Energy's *Wind Vision: A New Era for Wind Power in the United States* (DOE 2015b) with annual inflation increases to represent the operational expenditures (OpEx). The offshore strategy and cost reduction pathway reports used an operation and maintenance tool developed by the Energy Research Centre of the Netherlands that estimates the long-term annual average operation and maintenance costs and downtime of an offshore wind farm (Pietermen et al. 2011), which is used to investigate the sensitivity of OpEx to these spatial parameters, holding constant assumptions about technology and project characteristics. The same curve-fit methodology was applied for the maintenance portion of the model. The operational costs were calculated differently than the ECN model by using data from numerous sources including, but not limited to, The Crown Estate, the European Wind Energy Association, BVG Associates, and the University of Strathclyde. Again, additional information can be found in Appendix C of *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et. al 2016). The *2015 Cost of Wind Energy Review* used the ECN model for both the operation and maintenance portion of the OpEx calculations to ensure consistency with other studies—both internationally and within NREL—which are currently being conducted.

The fixed charge rate changes annually based on what is observed in the market. The *2014 Cost of Wind Energy Review* (Moné et al. 2015) and the current analysis based the fixed charge rate off the data of installed projects commissioned during the year of interest and the publicly available financial data on rates, debt/equity splits, and types of financing (e.g., nonrecourse project financing). The *National Offshore Wind Strategy* (Gilman et al. 2016) and *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016) reports used the *Annual Technology Baseline* methodology and general assumptions to calculate the fixed charge rate (see Appendix C of *The Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030* (Beiter et al. 2016) for financing assumptions).