2010 Cost of Wind Energy Review

S. Tegen, M. Hand, B. Maples, E. Lantz
P. Schwabe, and A. Smith

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Technical Report
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April 2012

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NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

In 2010, wind energy generated more than 2% of U.S. electricity, with some states generating more than 10% of their power from wind. The United States installed 5,116 megawatts (MW) of wind (American Wind Energy Association, AWEA 2011), which was one-quarter of all new electric capacity additions for that year. Wind energy capacity additions trailed the 6,000 MW of new coal and 7,200 MW of new natural gas additions in 2010 (Wiser and Bolinger 2011). With today's economic downturn, decision-makers are weighing the costs of different electric-generation resources with careful scrutiny. It is vital that we understand what those costs include and do not include when comparing technologies, analyzing the costs of wind energy over time, and seeking cost-improvement opportunities.

This report presents the best available information on the cost of wind energy in 2010, along with a summary of historical trends and future projections. One way to express the cost of wind energy is to calculate the levelized cost of energy (LCOE). The LCOE is a metric that has been used by the U.S. Department of Energy (DOE) for many years to evaluate the life-cycle costs of generation for energy projects and the total system impact of technology design changes. In simple terms, LCOE is defined as the ratio:

$$LCOE = \frac{\text{present value of total costs (\$)}}{\text{present value of all energy produced over project lifetime (megawatt−hours)}}$$

The LCOE equation used by NREL for this report is a standard method used to compare energy technologies (Short et al. 1995, EPRI 2007); it is described in detail below. There are four basic inputs to any LCOE equation: installed capital cost, annual operating expenses, annual energy production, and fixed charge rate (an annualized presentation of the cost of financing a wind project). This report provides context for each of the four major components and describes the LCOE equation in detail as well as the methodology, assumptions, and current market conditions for utility-scale land-based and offshore wind.

NREL used a variety of sources including industry data and model projections to arrive at the best representative data for U.S. wind projects in 2010. The modeled results presented in this document are based on the NREL Wind Turbine Design Cost and Scaling Model (Cost and Scaling Model) developed in 2006 (Fingersh et al. 2006). This cost of energy review summarizes the latest input assumptions for the Cost and Scaling Model as well as two of the outputs used by NREL: annual energy production and component capital costs.

Although the LCOE can be calculated in a variety of ways, this report presents only one of them. This report provides information about each element used in typical LCOE calculations, and the individual components can be used in other LCOE equations. The LCOE estimates in this report do not include prices to consumers (which are influenced by policies and other incentives e.g., production tax credit), transmission, integration, or potential revenues designed to reflect the cost of producing energy. The estimates are designed to reflect a typical U.S. wind plant.

For each variable represented in our 2010 LCOE equations, there is a range of possible values. Figure 1 shows the baseline assumptions and ranges of costs for the different parameters of LCOE that we used for land-based wind, and

Figure 2 shows the assumptions and costs for offshore wind. The key parameters include: installed capital cost (ICC), annual operating expenses (AOE), capacity factor, discount rate, and operational life of the project. For example, the capacity factors range from 25% to 45%, with an assumed 38% for our baseline turbines. Each of these ranges and assumptions are shown in Figure 1. Land-based wind assumptions and sensitivities for key LCOE input parameters are explained in their corresponding section in the paper.

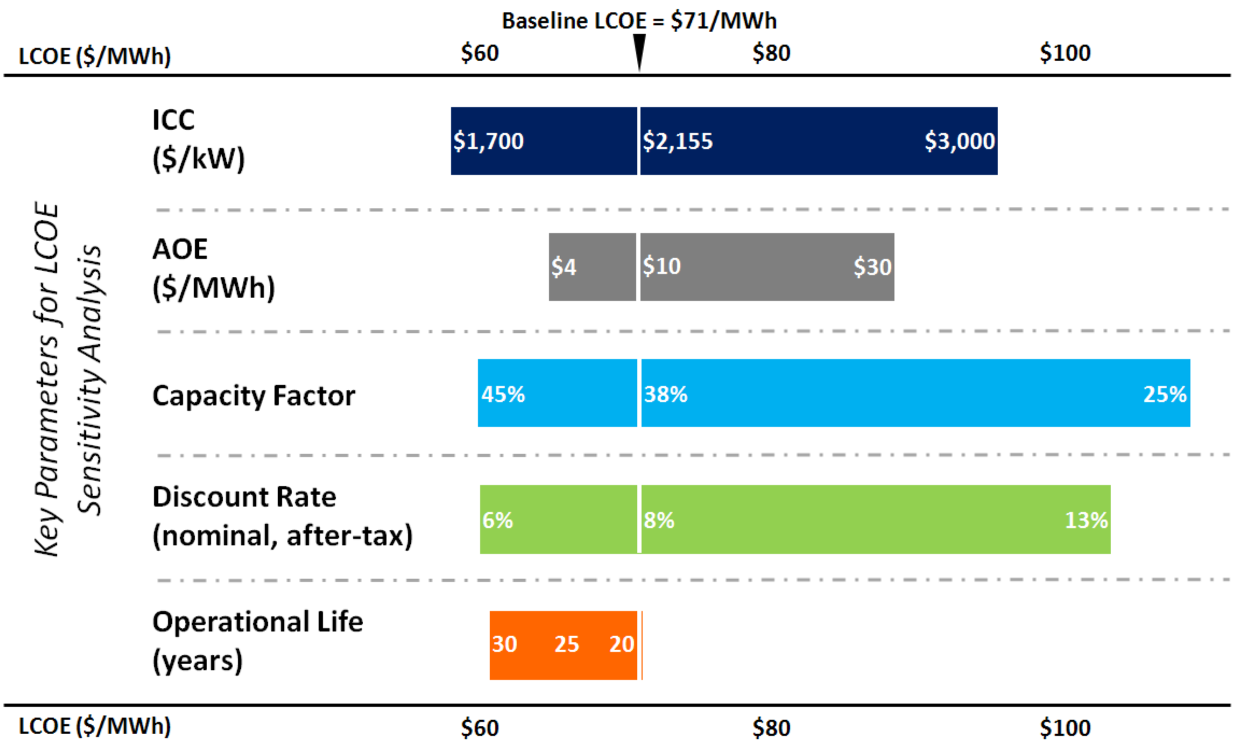

Figure 1. Land-based wind assumptions and sensitivities for key LCOE input parameters

Note that the LCOE ranges for land-based and offshore are different (and have different axes in these figures). For offshore wind, capacity factor ranges from 30% to 45% with an assumption of 39% for the baseline or reference turbine. As shown, there is a very wide range of installed capital cost for offshore wind projects. This is discussed further in the offshore wind capital cost section.

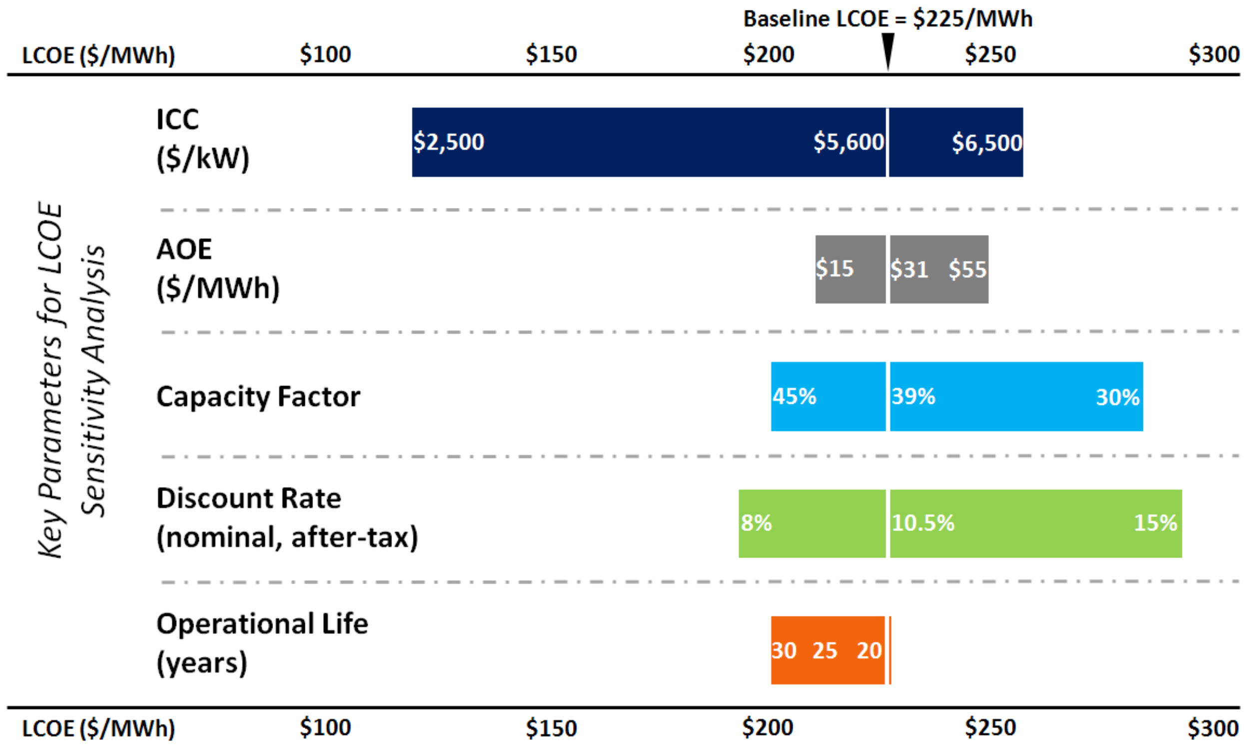

Figure 2. Offshore wind assumptions and sensitivities for key LCOE input parameters

The breakdown of wind turbine component and installation costs varies significantly between land-based and offshore turbines, as shown in Figures 3 and 4. More data are available on land-based turbines, allowing for a more detailed breakdown of their costs. The three major component cost categories are represented in the pie charts below: turbine (wind turbine components), balance of station (e.g., permitting, transport, assembly, installation), and soft costs (e.g., insurance, construction finance).

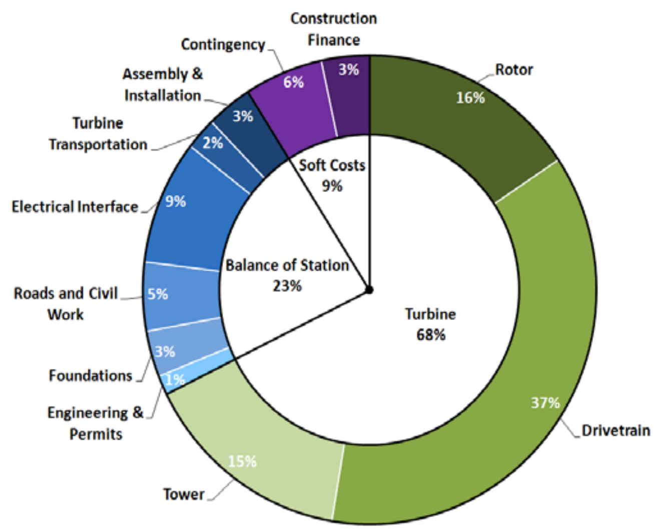

Figure 3. Installed capital costs for the land-based wind reference turbine

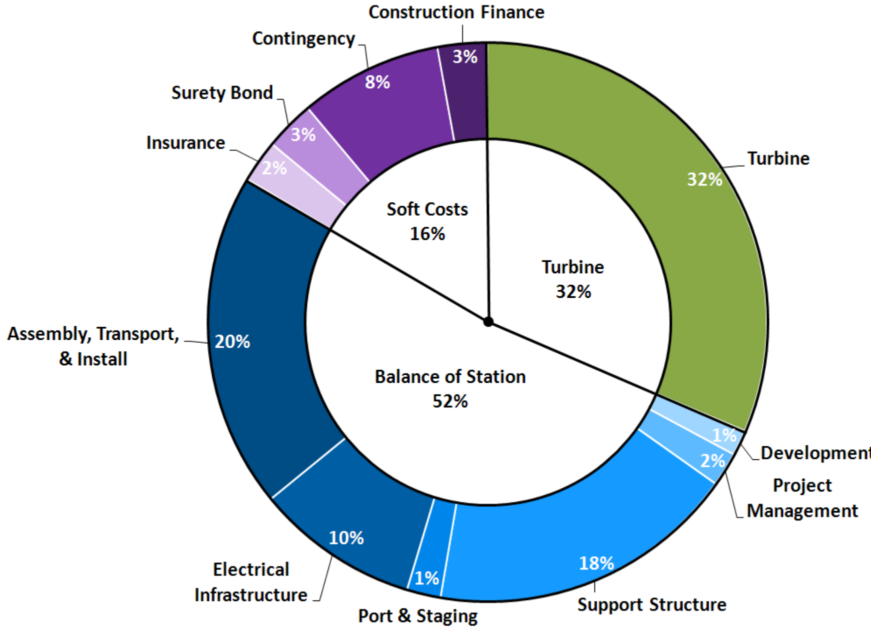

Figure 4. Installed capital costs for the offshore wind reference turbine

Results

Key findings from the 2010 Cost of Wind Energy Review include:

- The range of LCOE for land-based wind is \$58–\$108/MWh. The land-based reference project developed to represent the best available market-based data results in an LCOE of \$71/MWh based on assumptions discussed in this paper.
- The range of LCOE for offshore wind is \$118–\$292/MWh. The wide range is due mostly to the large variation in installed capital costs (\$2,500–\$6,500/kW). The offshore reference project developed to represent the best available market-based data results in an LCOE of \$225/MWh for offshore wind based on assumptions discussed below.
- Sensitivity scenarios for LCOE show that costs can vary widely depending on several key factors. The largest ranges in LCOE are seen in capital cost and financing assumptions for land-based and offshore projects and capacity factors for land-based wind.

Tables 1 and 2 show the major inputs to the LCOE equation for both land-based and offshore commercial-scale wind projects. These are the assumptions used to calculate LCOE for the typical or "reference" turbines in 2010. Results from the Cost and Scaling Model and from the LCOE calculation are also included.

Table 1. Summary of Inputs and Results for 1.5-MW Land-Based Wind Reference Turbine

	1.5 MW $/kW	1.5 MW $/MWh
Turbine Capital Cost	1,212	34
Balance-of-Station	418	12
Market Price Adjustment[1]	362	10
Soft Costs	163	5
Installed Capital Cost	***2,155***	***61***
After-Tax Annual Operating Expenses ($/kW/yr)	34	10
Fixed Charge Rate (%)	9.5	
Net Annual Energy Production (MWH/MW/yr)	3,345	
Capacity Factor (%)	38	
Total LCOE ($/MWh)	***71***	

Table 2. Summary of Inputs and Results for 3.6-MW Offshore Wind Reference Turbine

	3.6 MW Offshore $/kW	3.6 MW Offshore $/MWh
Turbine Capital Cost	1,789	62
Balance of Station Costs	2,918	101
Soft Costs	893	31
Installed Capital Cost	***5,600***	***194***
After-Tax Annual Operating Expenses ($/kW/yr)	107	31
Fixed Charge Rate (%)	11.8	
Net Annual Energy Production (MWh/MW/yr)	3,406	
Capacity Factor (%)	39	
Total LCOE ($/MWh)	***225***	

[1] The market price adjustment is the difference between the modeled cost and the market price for a typical wind turbine in 2010.

Future Work on Wind's LCOE

NREL intends to update this review of wind energy costs on an annual basis. This will help maintain a market perspective as well as develop a better understanding of the costs of individual components to the wind generation system. Over time, these reports will improve understanding of costs and their effects on LCOE, and will advance the bottom-up nature of information gathering by NREL. The data and tools developed will be used to help inform projections, goals, and improvement opportunities.

In fiscal year 2012, NREL continues to work with industry and partners such as Lawrence Berkeley National Laboratory to obtain project-specific data. NREL's wind analysis efforts include:

- A focus on understanding current and historical operation and maintenance (O&M) costs, including major component replacement costs.
- Analysis to estimate the impact of anticipated improvements to O&M for both land-based and offshore wind projects on LCOE.
- Development of models to better represent non-turbine project costs, e.g., foundations, electrical cabling, and installation, for a range of turbine and project sizes for both land-based and offshore wind technology.
- Analysis to quantify the impact of potential technology advances on system LCOE for land-based or offshore wind technology pathways.
- Development of a better understanding of barriers to wind power deployment such as transmission, radar, wildlife issues, and public acceptance. NREL will work with industry and others to quantify the costs of deployment barriers, and explain the impact of barriers on developable land with the intent of working toward barrier reduction in the future.
- Analysis of the costs of small and distributed wind technology.

NREL has gained a solid understanding of many components of a land-based wind turbine and system; and continued collaboration with industry will lead to better data and increased awareness of how much wind power system components cost now and how costs may be reduced in the future. For offshore wind, NREL has provided a best estimate for potential domestic wind power projects using the assumptions in this report. Most research projects indicate that the LCOE for both land-based and offshore wind will decline. This benchmark report and its updates will be a useful way to track cost data, inform DOE and industry of detailed cost trends, and provide a baseline for potential improvement strategies and metrics.

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Nomenclature

Abbreviation	Definition
AEP	Annual energy production
AOE	Annual operating expenses
AWEA	American Wind Energy Association
BLM	Bureau of Land Management
BNEF	Bloomberg New Energy Finance
BOEM	Bureau of Ocean Energy Management
BOS	Balance of station
Bps	Basis points
CF	Capacity factor
COE	Cost of energy
Cp	Coefficient of performance
CPE	Coastal Point Energy
CREBS	Clean renewable energy bonds
DOE	U.S. Department of Energy
EA	Environmental Assessment
ECA	Export Credit Agency
ECN	Energy Research Center of the Netherlands
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPC	Engineering, procurement and construction
EU	European Union
EWEA	European Wind Energy Association
FAA	Federal Aviation Administration
FCR	Fixed charge rate
FiTs	Feed-in tariffs
GDP	Gross domestic product
GW	Gigawatts
GWEC	Global Wind Energy Council
HV	High-voltage
HVDC	High-voltage direct current
ICC	Installed capital cost
IEC	International Electrotechnical Commission
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent power producers
Km	Kilometer
kW	Kilowatt
ITC	Investment Tax Credit
JEDI	Jobs and Economic Development Impacts
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized cost of energy

LGP	Loan Guarantee Program
LIBOR	London Interbank offered rate
LLC	Land-lease costs
LRC	Levelized replacement cost
LWST	Low-wind-speed technology
M	Meters
MACRS	Modified accelerated cost recovery system
MW	Megawatt
MWh	Megawatt-hour
NAICS	North American Industry Classification System
NWTC	National Wind Technology Center
NEPA	National Environmental Policy Act
NREL	National Renewable Energy Laboratory
NWTC	National Wind Technology Center
OCS	Outer Continental Shelf
OEMs	Original equipment manufacturer
O&M	Operation and maintenance
PFI	Public financial institution
PMDD	Permanent-magnet direct-drive
PPA	Power-purchase agreement
PPI	Producer price Index
PTC	Production tax credit
RCN	Research Council of Norway
REC	Renewable energy certificate
TSR	Tip-speed ratio
UCRF	Uniform capital recovery factor
UKERC	United Kingdom Energy Research Center
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
WACC	Weighted average cost of capital
WindPACT	Wind Partnership for Advanced Technology Components

1 LCOE Background

Levelized cost of energy (LCOE) is a metric used to evaluate the costs of generation for energy projects and the total system impact of design changes. A number of different methodologies have been developed, and the one used for this analysis is fully described in *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (Short et al. 1995).[2] The report's authors suggest calculating LCOE using a simplified formula designed to allow assessment of the true impact of technical changes. There are four major inputs into the LCOE equation. The first three—installed capital cost (ICC), annual operating expenses (AOE), and annual energy production (AEP)—enable this equation to represent system impacts from design changes. The total costs of financing are represented by the fourth major input—a fixed charge rate (FCR)—that determines the amount of revenue required to pay the carrying charges[3] on an investment.[4] In this report, we present the LCOE results in constant 2010 dollars to isolate them from the impact of inflation.

LCOE is especially important to understand for a technology such as wind energy, for which there is a constant tradeoff between maintaining or reducing capital investment and increasing energy capture. Comparing the LCOE for different technologies is most effective when one understands the four major inputs and how they fit together. This report does not attempt to compare wind energy to other technologies; however, the results can be used in such comparisons, if other technologies use the same method to calculate LCOE.

This report 1) explains the commonly accepted method the National Renewable Energy Laboratory (NREL) used to calculate LCOE for land-based and offshore wind; 2) describes NREL's 2010 reference turbines; 3) describes the NREL Wind Turbine Design Cost and Scaling Model inputs and results; and 4) assesses the relative impact of technical, operating, and financial assumptions on LCOE. Even though this report shows a number of assumptions and results, it does not capture the full spectrum of wind energy's costs. It does not consider policy incentives (such as the production tax credit), issues that developers face when planning and deploying wind projects (e.g., permitting, siting, public involvement), the current economic recession, transmission, or integration. These are important areas that can significantly impact costs for individual wind projects.

We use the following equation to calculate LCOE.

$$\text{LCOE} \equiv \frac{(FCR \times ICC) + \text{AOE}}{AEP_{net}}$$

Where:

LCOE $\equiv$ levelized cost of energy (\$/MWh)

[2] For an overview of cost of energy calculators and models, see Gifford et al (2011).
[3] Carrying charges include return on debt, return on equity, taxes, depreciation, and insurance.
[4] The FCR does not allow for detailed analysis of specific financing structures though these can be represented through the use of a weighted average cost of capital (WACC) as the discount rate input.

FCR	≡	fixed charge rate (%)
	≡	$\frac{d(1+d)^n}{(1+d)^n-1} \times \frac{1-(T \times PVdep)}{(1-T)}$
ICC	≡	installed capital cost ($/kilowatt [kW])
AEP_{net}	≡	net annual energy production (megawatt-hour [MWh]/yr)
		$8760 \times CF_{net}$
AOE	≡	annual operating expenses ($/kW/yr)
	≡	$LLC + O\&M * (1-T) + LRC$
d	≡	discount rate (%)
n	≡	operational life (years)
T	≡	effective tax rate (%)
$PVdep$	≡	present value of depreciation (%)
CF_{net}	≡	net capacity factor (%)
LLC	≡	land lease cost ($/kW/yr)
$O\&M$	≡	levelized O&M cost ($/kW/yr)
LRC	≡	levelized replacement cost ($/kW/yr)

1.1 Approach

Various data and models are used to estimate the cost of wind energy. For land-based wind technology, in particular, deployment of more than 40,000 megawatts (MW) of wind capacity in the United States provides significant data representing actual conditions in the U.S. market that impact the cost of wind energy. Offshore wind technology, on the other hand, is not currently deployed in the United States and the data supporting cost of wind energy is limited. Models to estimate a bottom-up cost of wind energy based on individual components that make up the capital cost, operating cost, and estimated energy production of hypothetical wind projects provide additional insight in combination with the data representing actual market conditions. The general approach for estimating the levelized cost of wind energy described in this report is as follows:

1. Evaluate market conditions and data for projects that have been installed in the United States (or in Europe when considering offshore wind technology) in a given year to understand installed project cost, annual energy production, operating costs, and representative turbine technology. A primary source for this data is the DOE Annual

Wind Technologies Market Report (Wiser and Bolinger 2011). The LCOE estimates are intended to reflect market conditions to the extent possible.

2. Supplement market data for realized projects with modeled data to define a "typical" project that is representative of the market conditions in a given year. NREL's *Wind Turbine Design Cost and Scaling Model* (Fingersh et al., 2006) estimates the capital investment cost and the annual energy production of a project based on turbine rated capacity, rotor diameter, hub height, and representative wind resource. This model uses scaling relationships at the component level (e.g., blade, hub, generator, tower) developed with curve-fit industry data, published scaling models, and turbine models developed through the WindPACT studies (e.g., Malcolm and Hansen, 2006) that reflect component-specific, often non-linear, relationships between size and cost (see Appendix C for a summary of the turbine component equations used in the model).[5] The use of this type of model provides additional details to represent specific wind technology while also reflecting high-level market conditions.
3. Combine market data and modeled data to estimate the primary elements necessary to calculate LCOE (i.e., installed capital cost, annual operating expenses, etc.) and provide details about wind technology that support the market data.

This approach is beneficial in that the "typical" project is described with a level of detail that is based on technology specifications, while market conditions are preserved. This approach is limited by the fidelity of the bottom-up model that uses technology specifications to estimate the primary LCOE elements. In order to associate modeled wind technology cost and performance with market data, two general gaps are identified.

1. The modeled installed capital cost tends to underestimate the market data, which are influenced by factors that are not captured by the model, as discussed in Section 2.1.
2. The modeled annual energy production estimate relies on an input assumption related to total losses across the reference wind project. Power losses are site and technology specific, and measurements for individual projects are not available.

The model estimates for installed capital cost and for capacity factor are forced to reflect market data by adjusting the "market adjustment" and "loss" terms in the model. Continued efforts to improve the fidelity of the bottom-up model should result in greater confidence associated with individual component estimates; however, differences between market data and modeled data will always exist. There may be a similar market adjustment for offshore wind when there is an established U.S. offshore wind market.

[5] The scaling relationships based on industry data or turbine model concepts that were developed in the early 2000s are used primarily to estimate wind turbine component cost. A methodology to associate wind turbine components with industry codes is utilized to account for inflation in material and labor costs on a component by component basis. This model does not capture other external market forces that have influenced the installed capital cost of wind projects in the United States. Therefore the bottom-up estimate of installed capital cost associated with the model is compared to the market-based observation of installed project cost. The difference is associated with non-modeled external market forces. Although the industry data and supporting model analysis for the scaling relationships is dated, the basic principles of wind turbine component scaling are representative of land-based turbines ranging from 750 kW to 5 MW, the range over which the data was originally developed.

The following sections of this report explain each component (ICC, AOE, AEP, and FCR) of the LCOE equation, market context, and the range of data for typical U.S. wind projects in the year 2010. All LCOE results are presented in 2010 U.S. dollars. This *Cost of Wind Energy Review* first explains the 2010 LCOE components for a 1.5-MW land-based reference wind turbine. Second, it describes the 2010 LCOE components for a 3.6-MW offshore reference wind turbine for which fewer data are available due to the lack of an offshore market in the United States.

2 Land-Based Wind

At the end of 2010, more than 40,000 MW of land-based wind capacity were installed in the United States, producing enough electricity to power 10 million homes (American Wind Energy Association, AWEA 2011). There are wind installations in 38 states, but the United States currently has no offshore wind capacity installed. Wind turbine capital costs and other component costs are presented using the most common land-based turbine size in the United States today, 1.5 megawatts (MW). In 2010, the average all-in[6] installed costs are $2,155/kilowatt (kW); and annual operating expenses are $34/kW (Wiser et al. 2011). The resulting levelized cost of energy (LCOE) is $71/megawatt-hour (MWh).

The all-in cost estimate reflects weighted installed cost data for projects constructed in 2010. Annual operating expense (AOE) estimates are from 65 projects built since 2000 (Wiser and Bolinger 2010). Primary data were supplemented by subject matter experts, wind project developers, and preliminary work on wind capital cost drivers (Bolinger and Wiser 2011).

Table 3 summarizes the land-based wind technology reference turbines by major line-item categories. Section 2.5.2 summarizes the detailed component costs. Each element of the LCOE equation is described in a section below.

[6] Overnight capital costs represent the cost of building a plant overnight and do not include financing or escalation costs. The "All-in" capital costs do include financing and escalation costs which can vary with risk perception, construction schedules, inflation expectations and other factors.

Table 3. Summary of Inputs and Results for Land-Based Turbines

	1.5 MW $/kW	1.5 MW $/MWh
Turbine Capital Cost	1,212	34
Balance of Station (BOS)	418	12
Soft Costs	163	5
Market Price Adjustment	362	10
Installed Capital Cost	2,155	61
Annual Operating Expenses (AOE) ($/kW/yr)	34	10
Fixed Charge Rate (%) (FCR)	9.5	
Net Annual Energy Production (AEP) (MWH/MW/yr)	3345	
Capacity Factor (%)	38	
Total LCOE ($/MWh)	71	

2.1 Installed Capital Cost (ICC)

Because the land-based wind industry has matured over the past 30 years, there are many data collection efforts and there is much experience in project installation and operation, contrary to offshore wind power. The annual *Wind Technologies Market Report* (Wiser and Bolinger 2011), published by the U.S. Department of Energy (DOE), presents a comprehensive picture of costs and trends. The report's capital cost category represents the total investment required to initiate a wind generation plant, including the turbine, foundations, roads, and permits. However, this report uses the Cost and Scaling Model to estimate component costs that are calibrated to the market-based total cost. This is done because recent trends described below introduce significant uncertainty in modeled estimations. The National Renewable Energy Laboratory (NREL) is working to develop a bottom-up model that associates physical parameters with cost estimates. While this approach is still likely to under-predict the total, it will provide greater fidelity in component cost and relative component cost change with the size of the turbine. This section on ICC describes historical trends in installed costs and the breakdown for the ICC representing a typical 2010 turbine. It also explains the assumptions used for the LCOE calculation. It is assumed that ICC is equal to the capacity-weighted average in this report.

2.1.1 Trends in Land-Based Wind ICC (1980-Present)

Wind energy first penetrated the commercial power sector in the Unites States in the early 1980s. Since that time, wind energy has grown to be a multibillion dollar, global industry with more than 200,000 MW installed worldwide (Global Wind Eneregy Council [GWEC] 2011, Bloomberg New Energy Finance [BNEF]) and more than 40,000 MW installed in the United States (Wiser and Bolinger 2011). Along with its emergence as a mainstream energy technology capable of supplying a substantial share of domestic electricity consumption in several countries (e.g., Denmark 26%, Portugal 17%, Spain 15%, Ireland 14%, and Germany 9%), wind energy capital costs have declined dramatically (Wiser and Bolinger 2011, Krohn et al 2009). However, after bottoming out in the early 2000s, wind energy capital costs have increased and were estimated to average $2,155/kW in 2010 (Figure 5).

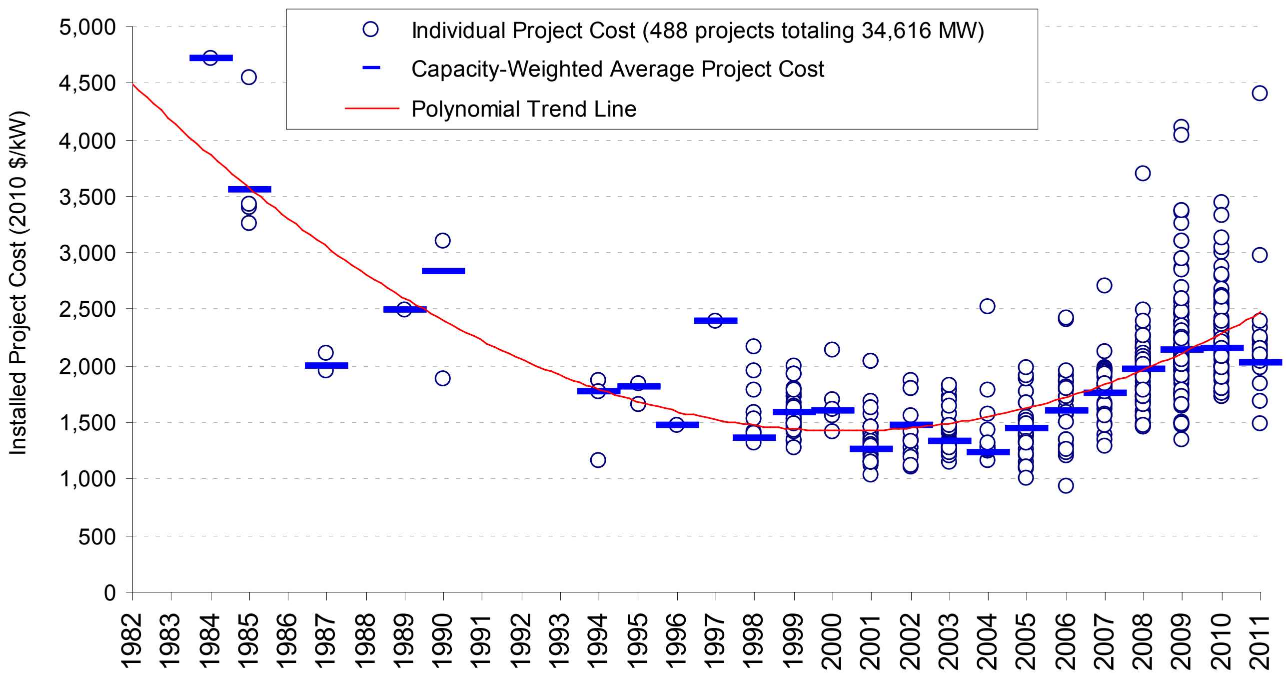

Figure 5. Historical wind energy capital costs in the United States

Source: Wiser and Bolinger (2011), Lawrence Berkeley National Laboratory

2.1.1.1 Explaining Historical Reductions in Capital Costs

Capital cost reductions occurring from the 1980s through the early 2000s are believed to have resulted from technological innovations and increased production volumes (Krohn et al 2009) leading to economies of scale. During this time period, technological innovations resulted in growth of commercial equipment from less than 100 kW to more than 1 MW in nameplate capacity, from rotor diameters of roughly 15 meters (m) to more than 70 m, and from tower heights of 20 m to more than 65 m. Technology innovations and learning associated with scaling also resulted in cost reductions in turbine system and component costs (on a $/kW basis). The development of larger turbines simultaneously led to a decline in balance-of-station costs on a per-kilowatt basis. Larger turbines resulted in reductions in required infrastructure (e.g., roads and underground cabling) and less time spent moving heavy equipment such as cranes between individual turbine sites. In addition, the emergence of larger projects (by nameplate capacity) supported greater dispersal of development and basic infrastructure costs that are born by the project developer (e.g., substation costs[7], high-voltage (HV) transmission tie line costs, operation and maintenance (O&M) facility costs), but increase only nominally with larger projects. The array of factors noted above coupled with a maturing industry also facilitated increases in the size (MW) and number of turbine purchase contracts, which allowed investment in manufacturing and production facilities, and further reduced wind energy equipment costs.

2.1.1.2 Explaining Recent Increases in Capital Costs

Wind energy project capital cost trends reversed course and began to increase in early 2000s. Capital costs have continued to increase since that time, although they reached a plateau in 2009–2010, and are expected to fall in coming years (see section 2.1.2) (Wiser and Bolinger 2011). Much of the increased capital cost associated with wind projects has been driven by increases in turbine costs. Turbine costs, in turn, have been affected by various factors elaborated in detail by Wiser and Bolinger (2011). One particularly critical factor in the increase in turbine costs was the dramatic increase in demand, both in the United States (Figure 6) and globally (Krohn et al 2009, Wiser and Bolinger 2011). Increase in turbine demand resulted in an array of constraints at various levels of the supply chain and extended project lead times, both of which placed upward pressure on capital costs. In addition, policy uncertainty in the U.S. market, generally the largest individual country market over this time period, slowed new manufacturing investment. This had a dual effect of compounding supply and demand constraints and discouraging new market entrants that might have increased competition.

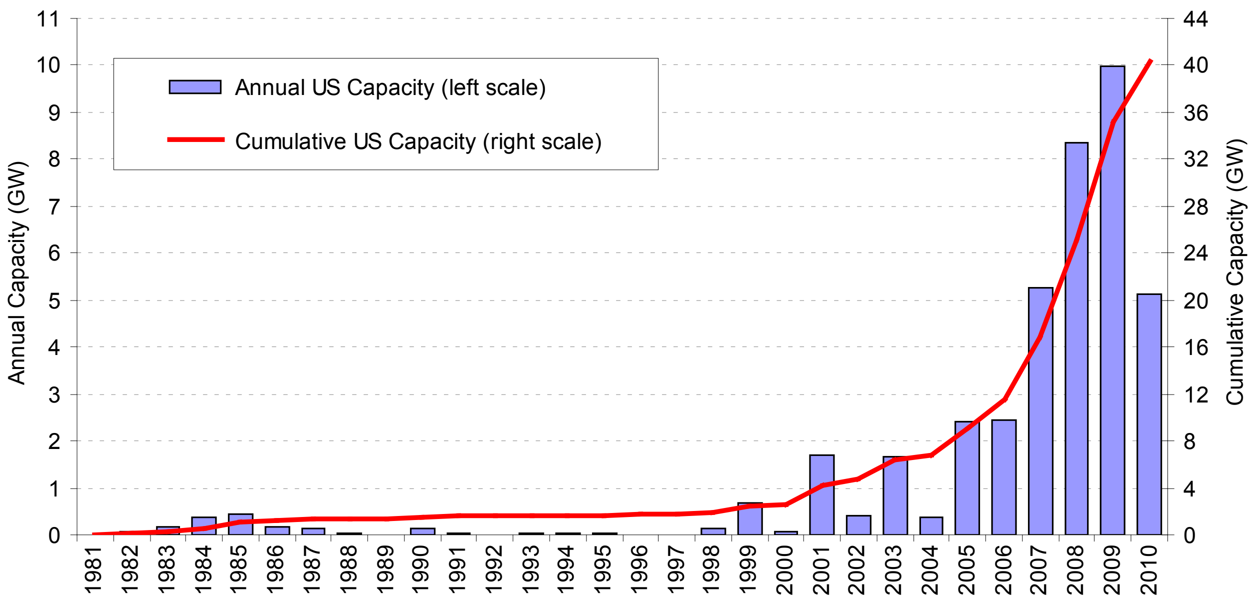

Figure 6. Growth in installed wind energy capacity

Source: American Wind Energy Association Project Database

[7] The ICC in this report includes connection to the substation, but does not include transmission costs.

Along with supply and demand constraints, increasing capital costs resulted from increasing commodity prices (e.g., steel, copper, cement, and composite materials) and labor rates, currency exchange rate variability (i.e., a decline in the value of the dollar relative to the Euro as the vast majority of equipment for much of the previous decade was imported from Europe), and continued technology development (technology scaling and enhanced grid services capabilities) (Wiser and Bolinger 2011). To some extent, the increasing costs of basic raw materials and labor also resulted in increases in costs for all types of electric power equipment, including conventional coal and gas-fired power plants (Chupka and Basheda 2007).

2.1.2 Near-Term ICC in the United States

Installed capital costs for wind projects increased at a compound average annual growth rate of about 10% between 2004 and 2009. However, 2010 capital costs were generally unchanged from 2009, and preliminary 2011 estimates are down about 5% from 2010 to approximately $2,000/kW (Wiser and Bolinger 2011). Moreover, contract data indicate that turbine prices have been declining since 2008. Wiser and Bolinger (2011) report reductions in turbine prices (price of the actual turbine as opposed to capital cost) for contracts signed in 2010 and 2011 that are generally 20% lower, with maximum reductions as much as 33% below the peak estimates of $1,500/kW in 2008.[8]

Researchers believe that recent declines in turbine prices are, in part, the result of increases in manufacturing investment and production capacity in the United States and around the world. Increases in manufacturing investment, production capacity, and industry growth in the United States have, in turn, been supported by the Section 48c Advanced Energy Manufacturing Investment Tax Credit as well as steady industry growth resulting from a recent brief period of relative federal policy stability.[9] U.S.-based nacelle production capacity grew from less than 2 gigawatts (GW) per year to nearly 8 GW in 2010 and now exceeds U.S. demand (Wiser and Bolinger 2011). However, turbine price declines have also been impacted by softening demand, particularly in the United States, as well as reductions in commodity prices and labor rates, among other factors. (For greater detail on these price reductions, see Bolinger and Wiser 2011.)

Turbine price reductions are generally expected to translate into future installed capital cost reductions. However, there is some lag time between cost reductions in turbine price contracts and reductions in installed costs, as contracts for turbines and power-purchase agreements (PPAs) are often placed well in advance of construction.[10] Looking at projects in late-stage development today, industry estimates suggest that project capital costs could fall an additional 20% from the preliminary 2011 estimates reported by Wiser and Bolinger (2010) at sites with

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8 Turbine prices still remain somewhat above their historical low in 2002–2003; however, considering the improvements in performance that have been observed over this same time period, the level of cost reduction remains noteworthy.

9 The primary federal incentive for wind, the production tax credit (PTC), was extended through 2012 in the 2009 American Recovery and Reinvestment Act (ARRA). This followed a series of continuous one and two year extensions of the tax credit since 2004. Combined, these policy provisions have supported both significant demand growth in the United States and manufacturing investment. ARRA also provided stability for the industry by authorizing the conversion of the PTC to an investment tax credit and initiating the 1603 U.S. Treasury Grant Program, which served to mitigate the dramatic reductions in available tax equity following the financial crises and recent recession.

10 Such practice was often a requirement up through 2008 as turbine lead times were regularly anticipated at one to two years during the peak of the supply and demand constraints of the market.

moderate to high wind speeds, with slightly higher project costs for low-wind-speed sites utilizing turbines with larger rotors.

2.1.3 Turbine components

NREL's Wind Energy Cost and Scaling Model (Fingersh et al. 2006, Maples et al. 2010) was used to estimate reference turbine costs for turbine components and balance of station (BOS) areas. Based on user-defined inputs, such as turbine rating, hub height, rotor diameter, and wind characteristics, the model uses its internal scaling relationships to develop turbine component and BOS costs as well as annual energy production (discussed later in Section 2.4). For land-based wind, initial results from the NREL model are augmented to reflect current market cost data (from actual installed projects) from industry data sources by using a market price adjustment. The contingency and construction financing components of ICC are calculated at 5% and 3%, respectively, of hard costs, which is consistent with industry averages.

Figure 7 demonstrates the breakdown of ICC for the NREL land-based baseline project. ICC components highlighted in shades of green are part of the turbine capital cost, ICC components highlighted in shades of blue are part of the BOS capital costs, and ICC components highlighted in shades of purple are part of the soft capital costs. For information on assumptions and inclusions of individual components, please refer to Appendix B and the NREL *Wind Turbine Design Cost and Scaling Model* report (Fingersh et al. 2006). These estimates were applied to an ICC estimate of $2,155/kW to generate individual component costs in dollars per kilowatt for the 2010 reference turbine. The cost breakdown is shown in Section 2.5.

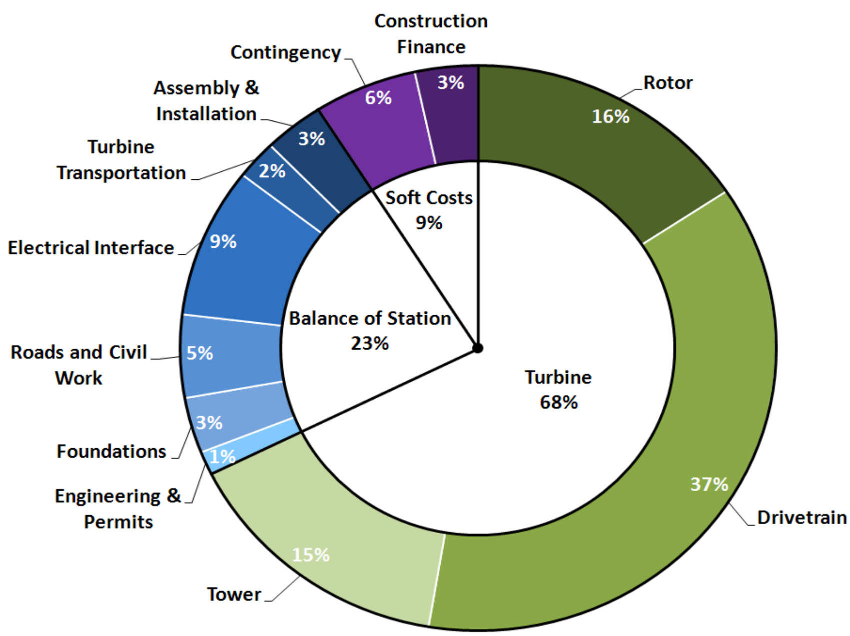

Figure 7. Installed capital costs for the land-based wind baseline project

The model focuses on the three-bladed, upwind, pitch-controlled, variable-speed wind turbine and its variants. The WindPACT rotor study, completed in 2002 (Malcom et al. 2006), was used as a primary scaling formula source with additional formula influences from the University of Sunderland.

In the process of programming these formulas and comparing them to current technology, a number of deviations were noted between 2002 data and current trends. Data for these comparisons came from several sources and are discussed in Appendix B. The result was a set of models, one for each turbine component and BOS area, that could be used to project the total LCOE for a wind turbine over a range of sizes and configurations. In most cases, cost and mass models are a direct function of rotor diameter, machine rating, tower height, or some combination of these factors. In cases where higher fidelity data are available, more sophisticated approaches are used or are under development. The scaling coefficients for all components start in 2002 dollars for the purpose of consistency. After a component cost is calculated, it is adjusted to 2010 dollars by using the producer price index (PPI) relevant to each component.[11] Where cost data were available from different years during the model's development, the data were converted to 2002 dollars before the scaling coefficients were developed. Cost data for land-based wind are derived primarily from the WindPACT studies (Cohen et al. 2008) and are, therefore, based on the same assumptions: a mature wind farm installation with mature component production. Assumptions for offshore wind are discussed in Section 3.

[11] The Producer Price Index in the United States is published by the Bureau of Labor Statistics. www.bls.gov/ppi

Table 4 summarizes the costs for individual components (including their contribution to LCOE) for the 1.5-MW turbine in the baseline project. Data sources for this table are located in Appendix B.

Table 4. Land-Based LCOE and ICC Breakdown

	1.5 MW $/kW	1.5 MW $/MWh
Rotor	**281**	**8**
Blades	**173**	**5**
Hub	**50**	**1**
Pitch mechanism & bearings	**54**	**2**
Spinner, nose cone	**4**	**0**
Drivetrain, nacelle	**634**	**18**
Low-speed shaft	**35**	**1**
Bearings	**19**	**1**
Gearbox	**137**	**4**
Mechanical brake, High sped shaft coupling	**2**	**0**
Generator	**85**	**2**
Variable-speed electronics	**105**	**3**
Yaw drive & bearing	**30**	**1**
Main frame	**119**	**3**
Electrical connections	**70**	**2**
Hydraulic, cooling system	**16**	**0**
Nacelle cover	**15**	**0**
Control, safety system, and condition monitoring	**29**	**1**
Tower	**269**	**8**
Turbine Capital Cost	**1,212**	**34**
Foundations	**57**	**2**
Turbine transportation	**40**	**1**
Roads & civil work	**85**	**2**
Turbine assembly & installation	**59**	**2**
Electrical interface and connections	**154**	**4**
Engineering & permits	**24**	**1**
BALANCE OF STATION	**418**	**12**
Market price adjustment	**362**	**10**
Contingency fund	**100**	**3**
SOFT COSTS	**462**	**13**
OVERNIGHT CAPITAL COST	**2,092**	**59**
CONSTRUCTION FINANCING COST	**63**	**2**
INSTALLED CAPITAL COST	**2,155**	**61**

2.1.4 2010 Costs

Projects installed in 2010 have saw a wide range of installed capital costs ranging from \$1,700/kW to \$3,000/kW for utility-scale wind farms, as shown in Figure 8 (Wiser et al 2011). As noted in this report, there are many factors that can lead to differences in a project's capital cost. Because of these project-to-project capital cost fluctuations, best estimates were established using the NREL Wind Turbine Design Cost and Scaling Model for each capital cost component, and then a market price adjustment was added to bring the all-in capital cost in line with the industry average. The market price adjustment accounts for fluctuations in component costs, profit margins, foreign exchange rates, supply chain constraints, and other market conditions. This report does not attempt to predict which capital cost components the market price adjustment influences, as it can vary drastically from one project to another.

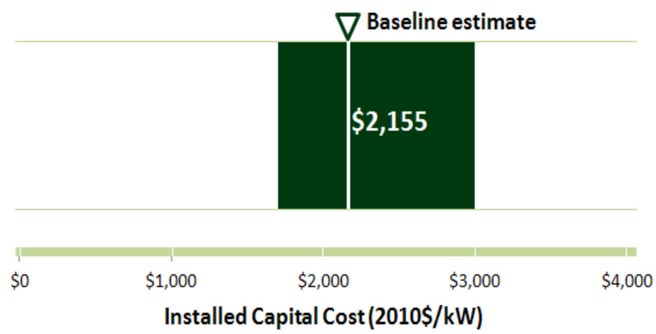

Figure 8. Range of ICC and NREL baseline estimate

2.2 Annual Operating Expenses (AOE) for Land-Based Wind

Annual operating expenses include land-lease costs (LLC), O&M wages and materials, and levelized replacement costs (LRC). Operation and maintenance costs are generally expressed in two categories: 1) *Fixed* O&M which includes known operations costs (e.g., insurance) and typically does not change depending on how much electricity is generated, and 2) *Variable* O&M, which includes planned and unplanned maintenance and other costs that may vary throughout the project. Variable O&M costs can vary depending how much electricity is generated by the project. Property taxes or payments in lieu of taxes may be included in O&M.

$$\text{AOE} \equiv \text{annual operating expenses (\$/kW/yr)}$$

$$\equiv \text{LLC} + \text{O\&M} * (1-\text{T}) + \text{LRC}$$

Currently, there are very limited publicly available data on AOE, so further research should be conducted on the costs, who pays the costs, and how they can be decreased. According to Wiser and Bolinger, O&M costs increase as projects age (Wiser and Bolinger 2011).

For this report, O&M estimates were calculated using current operating costs from the average of projects built between 2000 and 2009 (Wiser and Bolinger 2010). The AOE includes average estimated property tax payments from NREL's Jobs and Economic Development Impacts (JEDI) model and the LRC for major turbine components from Cohen et al. (2008). Wiser and Bolinger (2010) reported an average levelized value of \$9/MWh that generally included maintenance and repair costs as well as land-lease or rent payments. Property tax costs and an LRC bring the total AOE to $10/MWh. Wiser and Bolinger report that even with more recent data through 2010, the average O&M cost for projects built in the last decade is approximately $10/MWh. It should be noted that given the scarcity and varying quality of the data, AOE can vary substantially among projects (Wiser and Bolinger 2010), and the data presented here may not fully represent the challenges AOE presents to the wind power industry today. Figure 9 shows the range of AOE assumed in the sensitivity scenarios for the LCOE calculation from $4 to $30/MWh (based on plants with a commercial operation date of 2009, Wiser and Bolinger 2010) with the 2010 baseline estimate of $10/MWh.

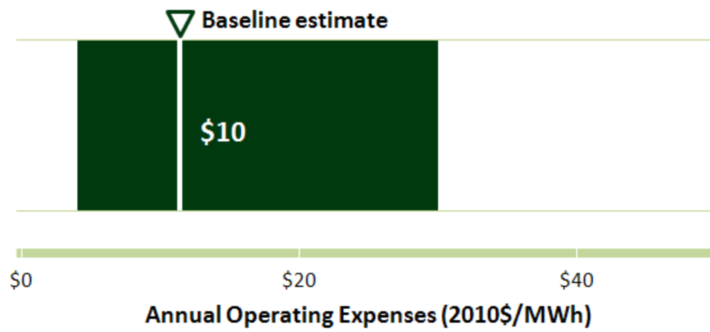

Figure 9. Range of AOE used in LCOE sensitivity calculations

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

Annual Energy Production (AEP) for this analysis was computed by the NREL Wind Turbine Design Cost and Scaling Model's AEP spreadsheet. The AEP spreadsheet is designed to compute annual energy capture and other related factors such as capacity factor for a wind turbine specified by certain generic input parameters. This strategy enables completion of the study's parameters. Parameters used for the calculation of AEP are presented in Table 5.

Offshore AEP is discussed in the offshore section of this report. The input parameters for calculating AEP can be grouped into three general categories: turbine parameters, wind resource characteristics, and losses.

Table 5. Baseline Annual Energy Production Input Assumptions

Turbine Parameters	
Turbine rated power (MW)	1.5
Turbine rotor diameter (m)	82.5
Turbine hub height (m)	80.0
Maximum rotor tip speed (m/s)	80.0
Tip-speed ratio at max Cp*	8.0
Drivetrain design	Geared
Rotor peak Cp	0.47
Wind Resource Characteristics	
Annual average wind speed at 50-m height (m/s)	7.25
Weibull K	2
Shear exponent	0.143
Losses	
Losses (array, energy conversion, line)	15%
Availability	98%

*Cp – Coefficient of performance

2.3.1 Turbine Parameters

Turbine parameters are characteristics specific to the turbine and are not dependent on the wind characteristics. These parameters consist not only of turbine size (rated power, rotor diameter, and hub height), but also of turbine operating characteristics (maximum rotor coefficient of performance [Cp], maximum tip speed, maximum tip-speed ratio [TSR], and drivetrain design). Holding all assumptions constant, one would typically see an increase in AEP when increasing turbine size or improving turbine operating characteristics. Turbine design parameters for the baseline turbines were chosen to reflect industry averages for land-based turbines installed in 2010. Because the geared drivetrain topology dominates the U.S. market, a geared drivetrain was selected for the baseline turbines.

Drivetrain design can greatly affect the turbine's AEP because of the variety of mechanical and electrical efficiencies of alternative designs. The baseline turbine is a three-stage geared drivetrain topology with a rated power efficiency of 90%. The power curve used accounts for losses that occur in the gearbox, generator, and power electronics (combined 92.5% efficiency at rated power) as well as the mechanical losses in the gearbox (97.5% efficient at rated power). As the power curve indicates in Figure 10, the drivetrain efficiency is significantly lower at lower power levels (70% efficient at 5% of rated power). The reduced efficiency at low power levels comes from both generator/power electronics (combined 78.9% efficient at 5% rated power) and increased mechanical losses in the gearbox (88.7% efficient at 5% rated power). Alternative drivetrain designs offer power curves of various shapes, as seen in Figure 10, which may increase or decrease AEP depending on the wind resource characteristics. The curves presented here show efficiencies for typical turbines of each drivetrain topology and may change from one manufacturer to another based on specific design choices.

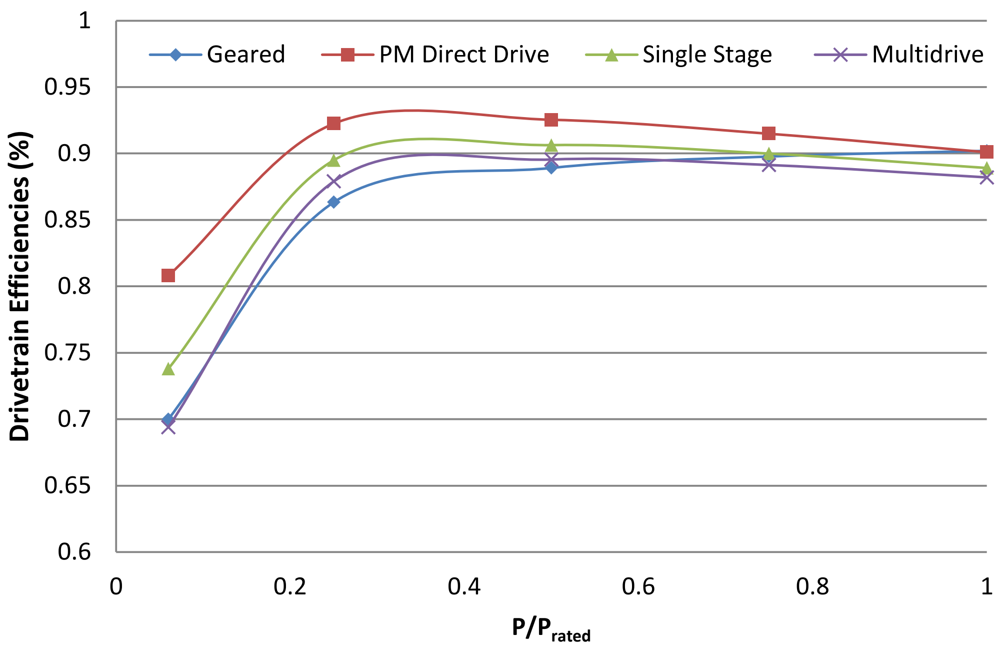

Figure 10. Efficiencies for various drivetrain designs from 6% to 100% of rated power

2.3.2 Wind Resource

Wind resource characteristics are parameters specific to the wind regime and are not dependent on the turbine design. Wind resource characteristics used in this simplified analysis include annual average wind speed with a distribution based on a chosen Weibull K value (k=2). Figure 11 demonstrates the wind speed probability distribution curves for a simplified class-4, land-based wind resource and a simplified class-6 offshore wind resource. Adjustments to the energy in the wind are made based on altitude above mean sea level and wind shear. We present a sensitivity of the LCOE to wind resource (by class) in Figure 20, section 2.8.

The annual average wind speed chosen for the baseline analysis is 7.25 m/s at a 50-m height because this is the wind class for which turbines of this size and configuration are designed. This wind speed is representative of a class-4 wind resource (7 to 7.5 m/s), which is slightly higher than industry averages for 2010. There are many reasons that 2010 wind projects are situated in lower wind speed resources, including attempts to lower transmission costs, noise impacts, and visual impacts among others. However, holding all assumptions constant, one would typically see an increase in AEP when increasing average wind speed, wind shear, or Weibull K values and a decrease in AEP when increasing altitude above mean sea level.

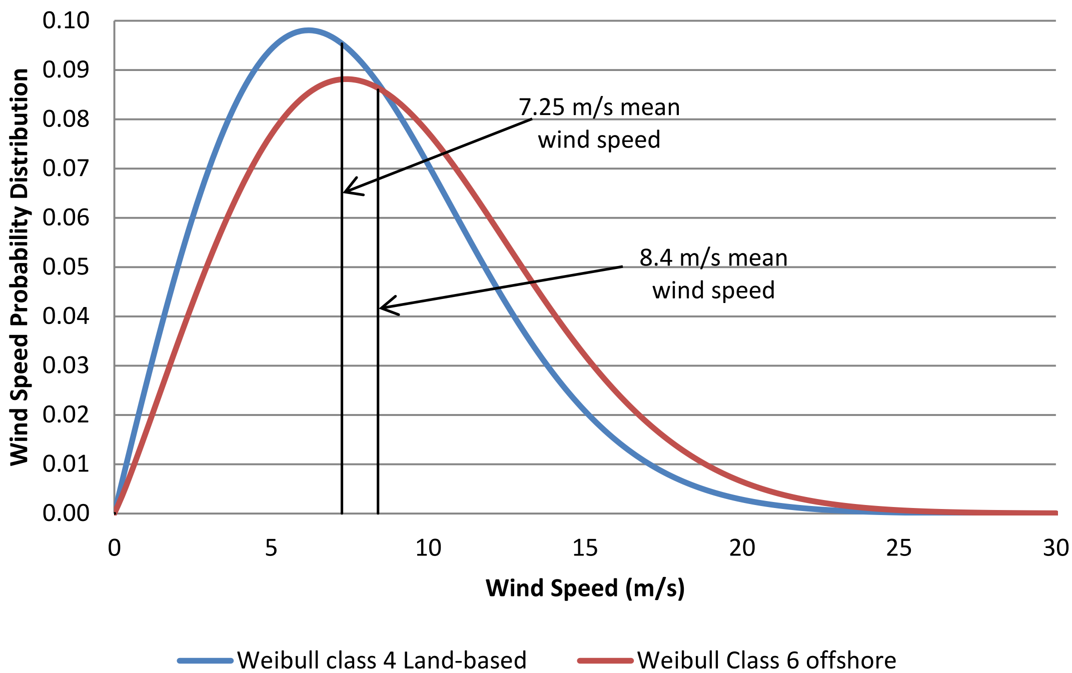

Figure 11. Wind speed probability distributions for the land-based and offshore wind resource characteristics used in this analysis

2.3.3 Losses

Losses are a unique input to AEP in that they are typically not modeled. Though some losses can be affected by turbine design or wind characteristics, in this simplified analysis, losses are treated as completely independent of any other input. Losses accounted for in this analysis include array losses, collection and transmission losses (from substation to the point of interconnection), and availability. Soiling losses are assumed to be zero. Net AEP is calculated by applying all losses to the gross AEP. Holding all assumptions constant, there is an increase in AEP when reducing losses or increasing availability.

Availability is estimated at 98% based on manufacturer reporting for turbine models sold in the United States in 2010 (e.g., manufacturers Acciona 2011, GE Wind 2011, Vestas 2011). It should be recognized that in some cases, the manufacturer definitions of availability may vary from that of operators or owners. Ninety-eight percent availability may be optimistic, but it's utilized because empirical data on availability for projects installed in 2010 are not publicly accessible.

Typical losses were estimated from fleet-wide performance data and modeled wind resource data for U.S. project sites over the four-year period between 2006 and 2009. Based on the wind resource map data associated with projects during this time, the fleet-wide capacity factor, the average turbine design characteristics (e.g., rating, hub height, rotor diameter), and the assumed availability, it was possible to estimate typical losses for a wind energy plant built in the United States between 2006 and 2009 with NREL's Cost and Scaling Model. Losses were estimated to be approximately 15%. (The 2010 data were not included as a full year of performance for projects installed in 2010 because a complete dataset was not available at the time of this report. The four-year period of 2006 to 2009 was used to reduce the impact of inter-annual wind resource variability in the fleet-wide capacity factor data).

Because a wind farm's AEP is dependent on so many independent factors, it is typical to see varying capacity factors from wind farm to wind farm and from year to year within wind farms. Figure 12 demonstrates the range of capacity factors from recent projects across the United States (Wiser and Bolinger 2011).

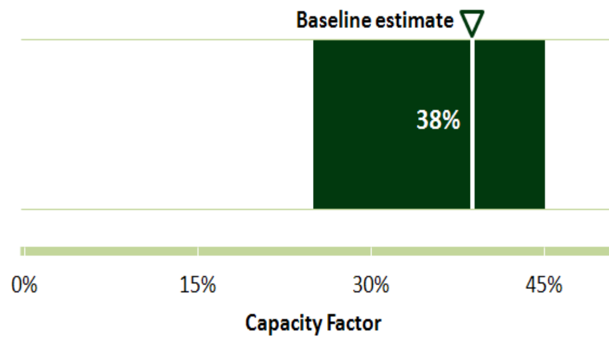

Figure 12. Range of capacity factors for land-based wind farms

Market data do not distinguish between different wind resources. A class-4 resource was chosen as typical when turbine parameters were defined for this reference project, although there is an apparent trend toward lower resource sites.

Table 6 shows the AEP, capacity factors, losses and availability for the land-based reference turbine operating in 2010.

Table 6. Wind Turbine AEP and CF Summary

	1.5 MW
AEPgross (MWh/MW)	4015
Gross Capacity Factor (%)	46
Losses & Availability (%)	17
AEP net (MWh/MW)	3345
Net Capacity Factor (%)	38

2.4 Land-Based Wind Finance

2.4.1 Overview of U.S. Land-Based Wind Finance Trends

This section describes the project financing assumptions for the report's representative land-based wind projects in the United States in 2010. A fixed charge rate, which is detailed below in section 2.4.4, was used for the LCOE equation. The availability of project financing for land-based wind energy generation in the United States improved in 2010 from the comparatively difficult finance environment in 2009 (Wiser and Bolinger 2011, AWEA 2011, DNV 2011). AWEA estimates that more than $11 billion in financing was raised in the wind sector in 2010 (AWEA 2011) compared to $8 billion dollars secured in 2009 (DNV 2011). The decrease in U.S.

wind installations in 2010 is attributed in part to the difficult financial environment in 2009 (Wiser and Bolinger 2011).

As shown in Figure 13, AWEA estimates that the wind sector successfully raised capital through 20 tax-equity transactions and 29 debt transactions in 2010 (AWEA 2011).[12] Figure 14 presents the corresponding aggregate dollar values of these financial closings in 2010, which totaled more than $11 billion dollars. Debt financing significantly exceeded tax-equity capital, with approximately $8.4 billion of debt compared to $2.7 billion in tax-equity investment raised in 2010 (AWEA 2011).

Additionally, the U.S. Department of the Treasury made 104 awards totaling more than $3.2 billion to wind projects in 2010 through its 1603 cash grant program (specifically the 30% cash payment program, U.S. Department of Treasury 2011). Of these awards, 52 were in excess of $5 million.

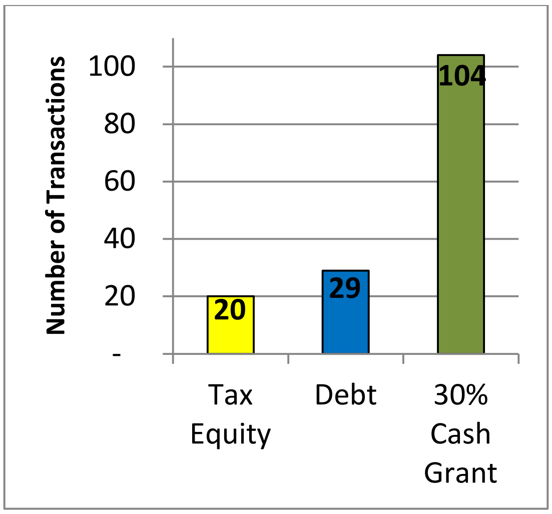

Figure 13. Number of financing transactions to the wind sector in 2010

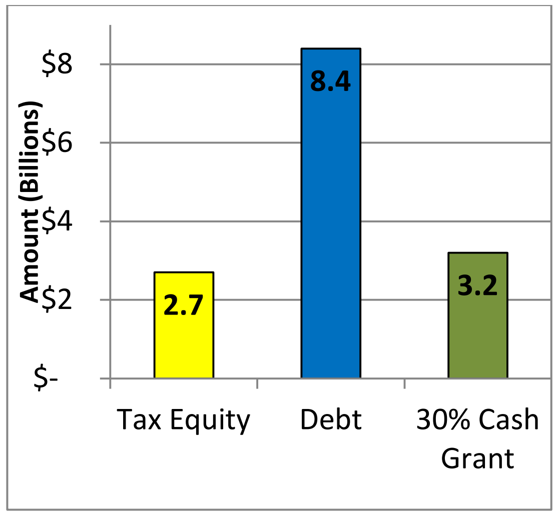

Figure 14. Sources of funds to the wind sector in 2010

The improved financing environment for renewable energy development in 2010 is further illustrated in Figure 15. Mintz (2011) estimates the number of active debt investors to U.S. renewable energy projects increased for the third consecutive year to 25 key lenders in 2010. Of the 25 active debt investors in 2010, 19 were non-U.S. entities (Mintz 2011). Following the loss of corporate profitability and tax-equity investors from the 2008 financial crisis, the number of active tax-equity investors rebounded from a low of around 11 investors by the end of 2009 to at least 16 investors by 2010—still shy of the high point of around 20 investors set in 2007.

[12] Tax equity transactions are financial arrangements in which the project ownership includes specialized investors – known as tax equity investors–with the ability to utilize the tax benefits as they become available during the project life. Tax equity transactions are often necessary to maximize the value of federal tax benefits and the accelerated depreciation schedules available to renewable energy projects. Debt transactions are project financial arrangements in which a lending institution provides debt to the project.

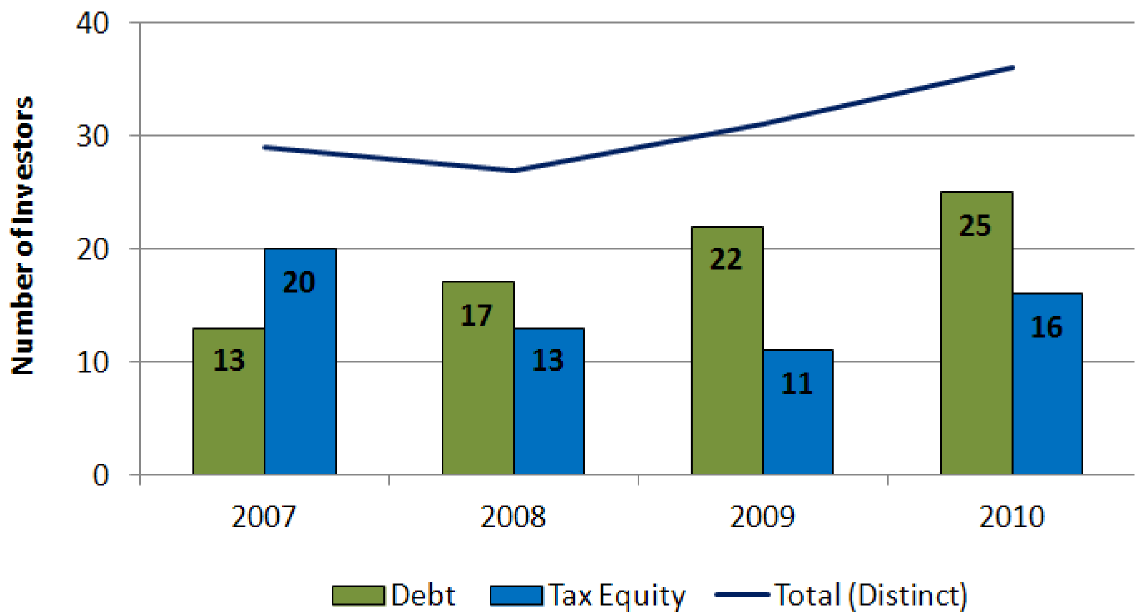

Figure 15. Number of debt and tax-equity investors to U.S. renewable energy projects, 2007–2010

2.4.2 Debt Interest Rates and Tax Equity Yields in 2010

As the availability of financing for wind project development increased in 2010, the required returns associated with debt and tax-equity investments showed modest decreases from 2009 levels. For example, Bloomberg New Energy Finance (BNEF) reports that both debt interest rates and tax equity yields decreased approximately 50 to 100 basis points (0.5% to 1.0%) from 2009 to 2010 (Bloomberg 2011).

Table 7 presents a sampling of reported[13] all-in annual interest rates for U.S. land-based wind projects in 2010 across a variety of industry sources. The range of reported all-in annual interest rates is fairly narrow, from around 5.8% to 7.1% before-tax considerations. As interest payments of debt obligations are tax deductible, the after-tax all-in interest rates are effectively lower, estimated from around 3.7% to 4.3%.[14]

Unless otherwise specified, all financing metrics are presented in nominal terms for consistency with financial industry convention.[15]

[13] Interest rates are reported by industry sources, listed in the first column. See Reference section for details.
[14] Assumes an effective tax rate of 38.9% and rounded to the nearest tenth of a percent.
[15] Nominal terms are expressed in the dollar values of a given year or series of years in contrast to real terms that adjust nominal value to remove effects of price changes over time.

Table 7. 2010 Land-Based Wind Debt Financing Terms

	All-in Interest Rate (Before-Tax)	All-in Interest Rate (After-Tax)
Mintz 2011	6.0% – 6.5%	3.7% – 4.0%
DNV 2011	7.1%	4.4%
Grace et al. 2011	6.5% – 7.0%	4.0% – 4.3%
Martin 2011	5.8% – 6.8%	3.5% – 4.1%
Wiser and Bolinger 2011	6.0%	3.7%

Turning to equity capital, Table 8 presents a range of reported tax-equity yields for U.S. land-based wind projects in 2010. The required yields on unlevered (e.g., no project-level term debt) tax-equity investment to U.S. wind projects ranged from approximately 7% to 10% in 2010, with several sources narrowing in on a mid-7% to high-8% after-tax yield (See Table 8). Although not always reported, the addition of project-level debt may increase the required after-tax-equity yield by about 300 basis points (3%) over unlevered yields. Inclusion of project-level debt increases the required yield to tax-equity investments because repayment of tax equity is subordinate to repayment of debt obligations. With the addition of project-level debt financing (i.e., levered), reported after-tax-equity yields ranged from approximately 10% to13% for high quality land-based wind projects in 2010.

Table 8. 2010 Land-Based Tax Equity Financing Terms

	Unlevered Yield (Before-Tax)	Levered Yield (After-Tax)
Mintz 2011	7.0% – 10.0%	10.0% – 13.0%
DNV 2011	9.0%	12.0%
Grace et al. 2011	7.5% – 8.5%	10.5% – 11.5%
Martin 2010	8.0% – 8.8%	11.0% – 11.8%
Wiser and Bolinger 2011	7.5% – 8.5%	10.5% – 11.5%

2.4.3 Discount Rate (d)

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. The following section provides a general overview of the discount rate assumption for wind energy projects in 2010 based on the debt and tax-equity financing terms discussed previously. It should be noted, however, that the financing terms or ownership type of any single renewable energy project will reflect the unique profile and risk of that particular project. Thus, a single discount rate representing the entire fleet of wind installations in 2010 should be viewed cautiously and is illustrative of general market trends and conditions only.

For this analysis, the discount rate is calculated as the after-tax weighted average cost of capital (WACC) for land-based wind energy projects. Calculation of the after-tax WACC requires assumptions for the debt-to-equity ratio, the pre-tax cost of debt, the effective marginal corporate tax rate, and the after-tax cost of equity. The assumed costs of debt and equity are based on the approximate midpoints of the ranges of the all-in debt interest rate and the levered tax-equity yields presented previously. The debt-to-equity ratio is based on the mid-point of reported typical leverage ratios of land-based wind projects by Harper et al. (2007). The base-case assumptions used in estimating the WACC include a debt ratio of 50%, a pre-tax all-in debt interest rate of 6.5%, an effective marginal corporate tax rate of 38.9%, and an after-tax levered tax-equity yield of 11.5%. These assumptions reflect a project-financing scenario using a mix of debt and tax equity in 2010. As shown in Table 9, the nominal, after-tax weighted average cost of capital for land-based wind energy projects in 2010 is estimated at approximately 8%. Assuming a 2.2% rate of inflation in 2010, the real after-tax discount rate is estimated at 5.7%.[16]

Table 9. 2010 Land-Based Discount Rates Using the After-Tax WACC

Nominal Discount Rate (After-Tax)	Real Discount Rate (After-Tax)
8.0%	5.7%

2.4.4 Economic Evaluation Metrics (FCR and UCRF)

Two metrics, the uniform capital recovery factor (UCRF) and the fixed charge rate (FCR), are used in the economic evaluation of wind energy investments. Both the UCRF and the FCR can be used to estimate the LCOE for wind, but differ in their treatment of corporate income taxes and book depreciation among other costs.

The UCRF 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 et al. 1995). The UCRF can be thought of as the reoccurring 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 UCRF). Notably, the UCRF ignores the impact of corporate income taxes, thus is applicable to a no-tax investment scenario such as from a government investment. The UCRF is calculated according to the following formula:

$$UCRF = \frac{Discount\ Rate}{1 - \left(\frac{1}{1 + Discount\ Rate}\right)^{Lifetime}}$$

Similarly, the FCR is a related metric to the UCRF, but can include any number of different costs not captured in the UCRF. The FCR is defined as "the amount of revenue per dollar of investment that must be collected annually from customers to pay the carrying charges on that investment. Carrying charges include return on debt and equity, income and property tax, book depreciation, and insurance" (Short et al. 1995).

[16] Converted using the standard Fisher equation. The 2.2% rate of inflation is based on the 2010 Annual Energy Outlook by the Energy Information Administration (EIA 2010).

The FCR is defined as:

$$FCR = \frac{Discount\ Rate}{1 - \left(\frac{1}{1 + Discount\ Rate}\right)^{Lifetime}} \times \frac{1 - (T\ \times PVDepreciation)}{1 - T}$$

Where:

T = marginal corporate income tax rate (state and federal)

$PV\ Depreciation$ = present value of depreciation.

Using this definition, the FCR represents the before-tax revenue that a profit-maximizing firm would require annually to cover its cost and carrying charges of an investment and to achieve its desired after-tax return.

Table 10 presents the estimated FCR and UCRF in nominal and real terms using the after-tax WACC discount rate of 8% and 5.7%, respectively, a lifetime of 20 years, and a present value of depreciation factor of 81.1%.[17] The nominal FCR is estimated at 11.4% and the real FCR is estimated 9.5%. The nominal and real UCRF are estimated 10.2% and 8.5%, respectively. As noted in Short et al. (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 and both investments using an after-tax method).

Table 10. 2010 FCR and UCRF Economic Evaluation Metrics

Fixed Charge Rate		Uniform Capital Recovery Factor	
Nominal	Real	Nominal	Real
11.4%	9.5%	10.2%	8.5%

2.4.5 Financial Sensitivities

The financing costs for land-based wind projects can also affect the total cost of delivered power through variations in the debt payments and investor's return requirements. These variations are captured in this analysis through differing estimates of the WACC. Figure 16 shows a range for the discount rate for the land-based wind project as well as the NREL baseline assumption of 8%. The discount rate is the same as the WACC for this simple calculation. In the low-cost case, a nominal after-tax WACC of 6% represents a scenario in which a wind project is financed with a high percentage of debt (e.g., 60%), and the cost of capital for debt and equity are at the low end of the ranges observed in 2010. The high-cost case of a nominal, after-tax WACC of 13% is based on an analysis by the California Energy Commission that reports a high-cost WACC of approximately 13% for renewable energy technologies (Klein et al. 2010). This higher cost estimate is indicative of a scenario in which the electricity from a renewable energy project is not contracted through a long-term power-purchase agreement and represents a higher risk to the project's investors.

[17] See Table A-1 in Appendix A for calculation of the present value of depreciation factor.

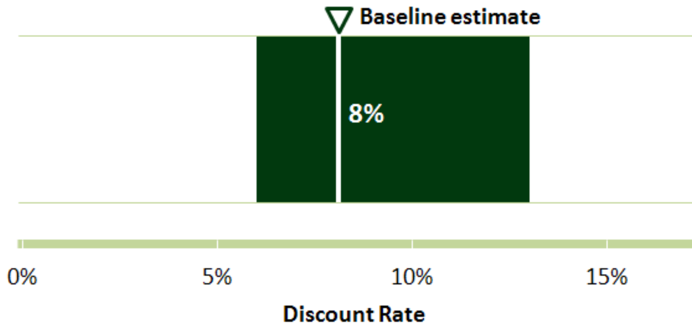

Figure 16. Range of discount rates and NREL baseline

2.4.6 Project Life Sensitivities

FCR and UCRF are based on the project finance period. The technology may continue to operate beyond the period over which financing is scheduled, so it is important to understand that the project finance period may not be the actual period of wind project performance. The assumed project life can affect the cost of delivered power by changing the period over which investment costs can be amortized. As shown in Figure 17, the preceding economic evaluation metrics assumed a 20-year average project life for land-based wind turbines. Extending the assumed project life of a wind turbine to 25 or 30 years lowers the annualized cost of energy as the fixed capital costs of the project are amortized over a longer period. The impact of 25- and 30-year project lifetimes on the FCR and UCRF are shown in Table 11.

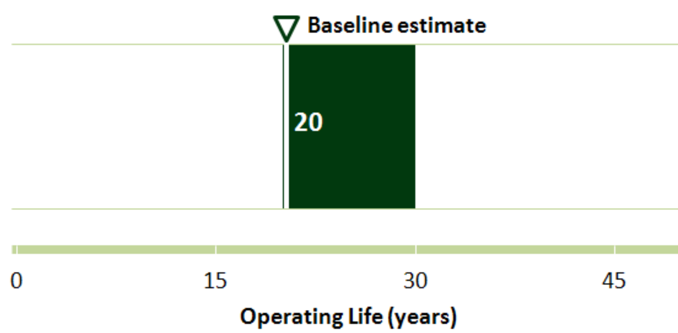

Figure 17. Range of operating life and NREL baseline

Table 11. FCR and UCRF Sensitivity to Project Lifetime

25-Year Operational Life				30-Year Operational Life			
FCR		UCRF		FCR		UCRF	
Nominal	Real	Nominal	Real	Nominal	Real	Nominal	Real
10.5%	8.5%	9.4%	7.6%	10%	7.9%	8.9%	7.0%

2.5 LCOE Summary

2.5.1 Description of Baseline Project

A combination of market observations and modeled results has led to the establishment of the NREL land-based 2010 representative project, summarized in Table 12. The reference project consists of 200 turbines with a rated capacity of 1.5 MW each.

Table 12. Land-Based Wind Project Assumptions Summary

General Assumptions for the 1.5 MW Reference Turbine	
Project capacity (MW)	300
Number of turbines	200
Turbine capacity (MW)	1.5
Site	
Location	Heartland
Layout	Grid
Wind speed (m/s at 50 m elevation)	7.25
Wind speed (m/s at 80 m elevation)	7.75
Net capacity factor	38%
Technology	
Rotor diameter (m)	82.5
Hub height (m)	80
Gearbox	3-stage
Generator	Asynchronous
Foundation	Spread Foot
Cost	
Capital cost (millions)	$646.5
Contingency (millions)	$30
AOE ($/MWh)	$10
Discount rate (real)	5.7%
Discount rate (nominal)	8%
Operating life (years)	20
Fixed charge rate (real)	9.5%

The project is located in the heartland region of the United States in a simple grid layout. Annual average wind speeds for the site are assumed to be 7.25 m/s at 50 m elevation (7.75 m/s at 80 m elevation), which is consistent with a class-4 wind resource.

Rotors for the turbines are 82.5 m in diameter and sit at a hub height of 80 m. The turbines are of a typical drivetrain design with a 3-stage planetary/helical gearbox feeding a high-speed asynchronous generator. Each turbine is secured to the ground with a standard spread-foot foundation design.

The all-in capital cost for the project is assumed to be at $646.5 million or about $2,155/kW. A $30-million contingency fund is assumed to cover any possible increases in capital costs. The AOE is set at $10/MWh. Operating life is assumed to be 20 years with a discount rate of 5.7%. All LCOE results are presented in 2010 dollars.

2.5.2 LCOE Calculation

Based on the NREL land-based baseline project inputs (LCOE, ICC, AEP, AOE and FCR) described above and using the LCOE equation outlined in the introduction, a land-based baseline LCOE was computed to reflect a typical wind plant in 2010.

Table 13 summarizes the costs for individual components (including their contribution to LCOE) for the 1.5-MW turbine in the baseline project. Data sources for this table are located in Appendix B. Figure 18 presents a graphical representation breakdown of the 1.5-MW LCOE.

Table 13. Land-Based LCOE and Component Cost Breakdown

	1.5 MW $/kW	**1.5 MW $/MWh**
Rotor	281	8
Blades	173	5
Hub	50	1
Pitch mechanism & bearings	54	2
Spinner, nose cone	4	0
Drivetrain, nacelle	634	18
Low-speed shaft	35	1
Bearings	19	1
Gearbox	137	4
Mechanical brake, HS coupling	2	0
Generator	85	2
Variable-speed electronics	105	3
Yaw drive & bearing	30	1
Main frame	119	3
Electrical connections	70	2
Hydraulic, cooling system	16	0
Nacelle cover	15	0
Control, safety system, and condition monitoring	29	1
Tower	269	8
Turbine Capital Cost	1,212	34
Foundations	57	2
Turbine transportation	40	1
Roads & civil work	85	2
Turbine assembly & installation	59	2
Electrical interface and connections	154	4
Engineering & permits	24	1
BALANCE OF STATION	418	12
Market price adjustment	362	10
Contingency fund	100	3
SOFT COSTS	462	13
OVERNIGHT CAPITAL COST	2,092	59
CONSTRUCTION FINANCING COST	63	2
INSTALLED CAPITAL COST	2,155	61

	1.5 MW $/kW	1.5 MW $/MWh
Levelized replacement cost ($000/yr)	11	3
Labor, equipment, facilities (O&M) ($000/yr)	15	5
Land lease cost ($000/yr)	7	2
ANNUAL OPERATING EXPENSES	34	10
Net 7.25 m/s AEP (MWh/MW)	3345	
Capacity factor	38%	
Fixed charge rate (FCR) (real, after-tax)	9.5%	
LCOE ($/MWh)	71	

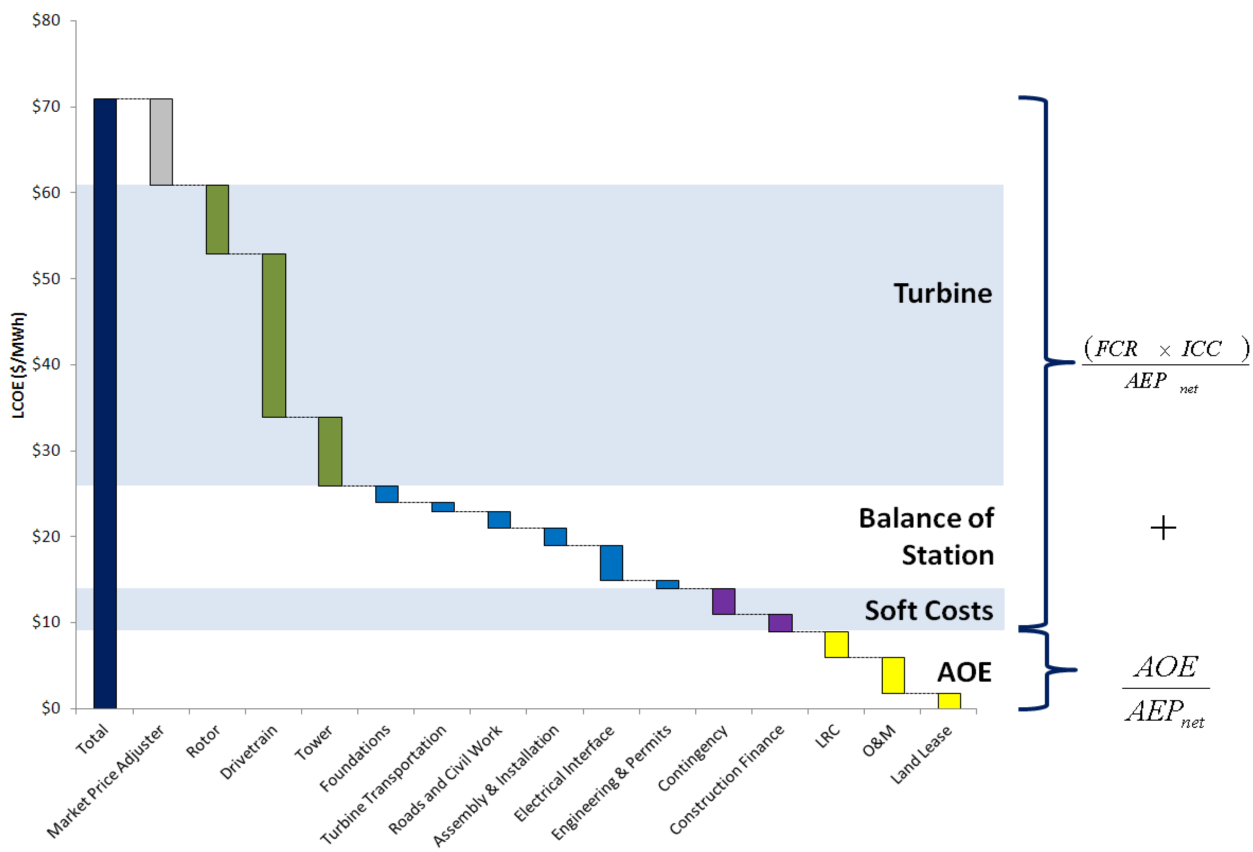

Figure 18. Cost breakdown for 2010 land-based wind project

2.6 LCOE Sensitivities

The baseline input parameters described above represent a typical wind project with the understanding that each project has its own unique characteristics. These input parameters for a near-term, land-based wind project are subject to considerable uncertainty; therefore, it is beneficial to investigate the impacts the variability may have on LCOE. The sensitivity analysis focuses on five major variables: 1) capital cost, 2) operating cost, 3) capacity factor, 4) discount rate, and 5) operational lifetime. Sensitivities to these variables are tested across the ranges identified in previous sections. Figure 19 presents the results of these sensitivity tests.

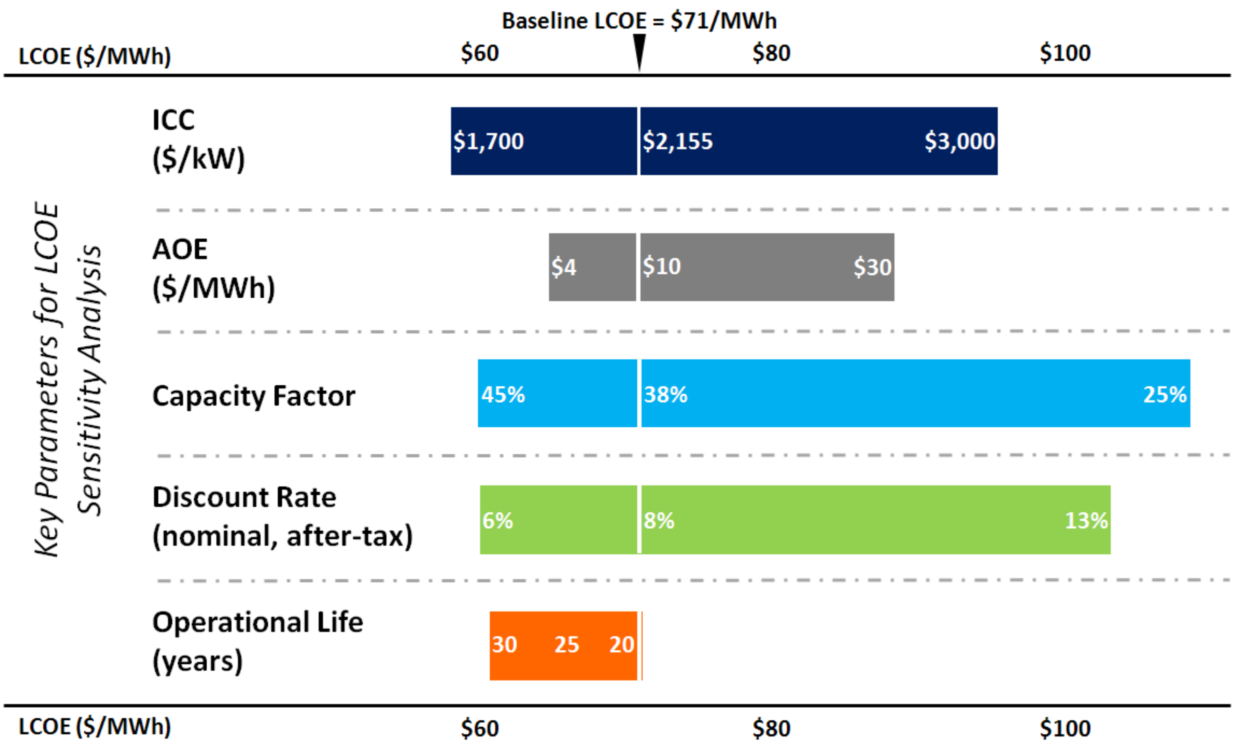

Figure 19. Sensitivity of land-based wind LCOE to key input parameters

The sensitivity analysis was conducted by holding all baseline assumptions constant and altering only the variable in question. Sensitivity ranges were selected to represent the highs and lows seen in industry. This selection of ranges provides insight into how real-world ranges influence LCOE. The sensitivity analysis yielded ranges in LCOE from a low of $58/MWh to a high of $108/MWh—a low-to-high increase of nearly double the lower bound. Analysis shows that all variables have similar potential with respect to lowering LCOE; however, the capacity factor and discount rate show the highest influence with respect to an increase in LCOE.

The high and low LCOEs should not be taken as absolute ranges because a change in one variable may affect another or interact in an additive or canceling manner. Each individual wind project has a unique set of characteristics, and the sensitivities analyzed here are not definitive. The key parameters are representative of a market ranges, but do not reflect individual technologies and are not related to each other.

2.7 LCOE Projections

Recent turbine price reductions are particularly notable because they have occurred even as the performance of turbine equipment has continued to improve. Incremental growth in rotor diameters and hub heights has resulted in continuous increases in energy production for new turbine models. By combining increased performance with lower turbine prices, shorter equipment lead times, and improved warranty and maintenance terms, it is anticipated that the cost of wind energy could fall significantly in the near term. To begin to quantify the potential magnitude of these recent market developments, a simplified cost of energy analysis was conducted by analysts at NREL and Lawrence Berkeley National Laboratory (LBNL).[18]

Analysis inputs, summarized in Table 14, are intended to reflect industry-wide average estimates of capital costs, operating costs, project losses, and other terms. In addition, the estimates rely on modeled turbine performance assuming 50-m sea level wind speeds (adjusted to hub height with the $1/7^{th}$ power law), a 20-year project life, and a 38.9% effective corporate tax rate. This preliminary work suggests that projects slated for construction in the next one or two years could result in a cost of energy of approximately $40/MWh for mid class-4 wind resource sites, when the production tax credit and depreciation (modified accelerated cost recovery system or MACRS) (see Figure 20) are included, and $70/MWh when federal incentives are not included. As such, projects in late-stage development today could see an LCOE that is at a historical low within fixed wind resource classes in the very near future.

Table 14. Inputs in Simplified LCOE Estimates 2002-2013

Characteristics	2002–2003	2009–2010	Current Turbine Pricing: ~2012–2013		
Technology Type	**Standard**	**Standard**	**Standard**	**Low Wind**	**Low Wind**
Nameplate capacity	**1.5 MW**	**1.5 MW**	**1.62 MW**	**1.62 MW**	**1.62 MW**
Hub height	**65 m**	**80 m**	**80 m**	**80 m**	**100 m**
Rotor diameter	**70.5 m**	**77 m**	**82.5 m**	**100 m**	**100 m**
Installed capital cost	**$1,300/kW**	**$2,150/kW**	**$1,600/kW**	**$1,850/kW**	**$2,025/kW**
Operating costs	**$60/kW-year**	**$60/kW-year**	**$60/kW-year**	**$60/kW-year**	**$60/kW-year**
Losses (availability, array, other)	**15%**	**15%**	**15%**	**15%**	**15%**
Financing cost/ discount rate (nominal)	**9%**	**9%**	**9%**	**9%**	**9%**

Source: Wiser et al (2012)

[18] This analysis focuses exclusively on the impacts associated with increased performance and reduced capital costs; financing, O&M, losses, and all other inputs are held constant. More detailed analysis would also consider the impact of improvements in these areas.

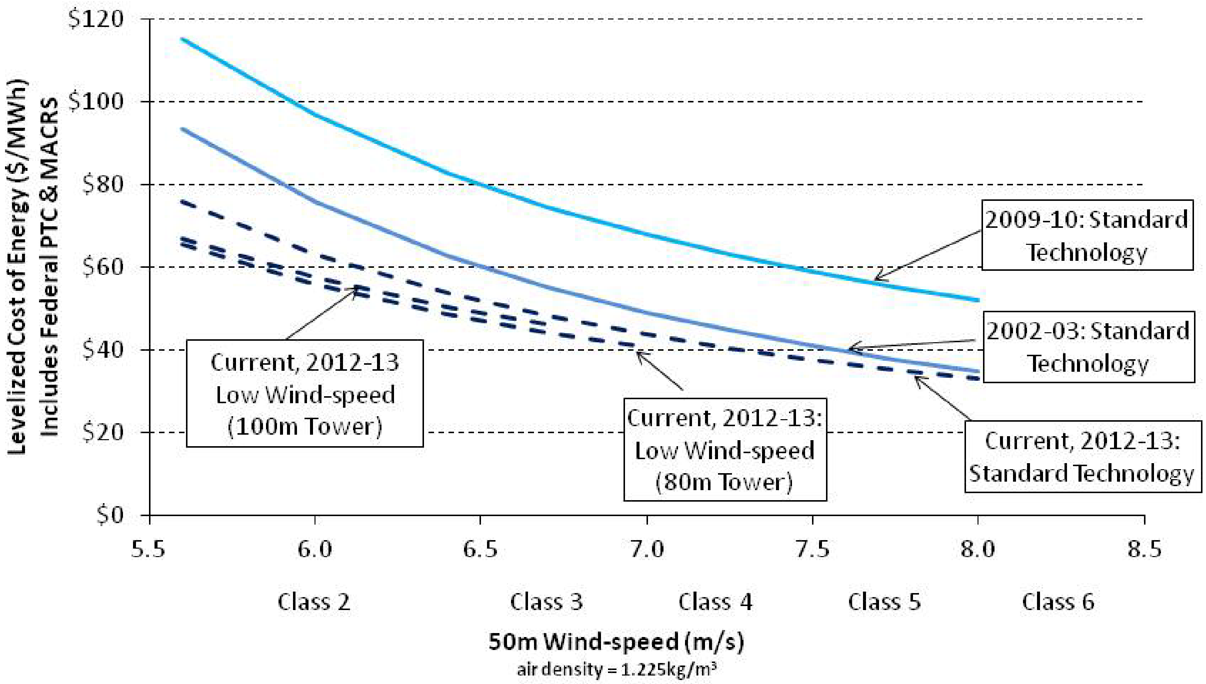

Figure 20. Estimated cost of energy for wind turbines installed in 2002–2003, 2009–2010, and to be installed in 2012–2013 across wind speed classes

2.8 Long-Term Expectations (through 2030)

Over the long term, capital cost and turbine price reductions observed historically and again more recently are expected to continue. However, the degree of reduction will depend on the push to continue to increase wind turbine performance and provide an increasing level of grid services capabilities. Ultimately, both declining capital costs and increasing performance are likely to drive reductions in the overall cost of wind energy. Supply and demand and other market factors (e.g., commodity prices, labor costs) will also continue to play a role, but their impact is generally expected to result in short-term variability without dramatically altering the long-term trends (decade-level). Reduced cost estimates over the long term are typically developed via three specific analytical approaches; 1) the learning curve, 2) expert elicitation, and 3) the engineering model approach. An overview of each of these methods along with a description of their respective strengths and weakness can be found in Lantz et al. (2012). In practice, however, analysts typically use some combination of these methods to develop future cost estimates.

2.9 Summary of Land-Based Wind Technology LCOE Projections

Figure 21 compiles data from 13 different analyses (including both research studies and policy analysis modeling inputs) and 18 different scenarios that illustrate the expected range of the future cost of land-based wind energy.

The studies analyzed for this report reflect each of the three approaches noted above (see Lantz et al. for examples of each), as well as other methods (e.g., market analysis) to project future costs. The data in the majority of these studies suggest a roughly 0%–40% reduction in land-based LCOE through 2030 with at least one study assuming no reductions in cost through 2030.

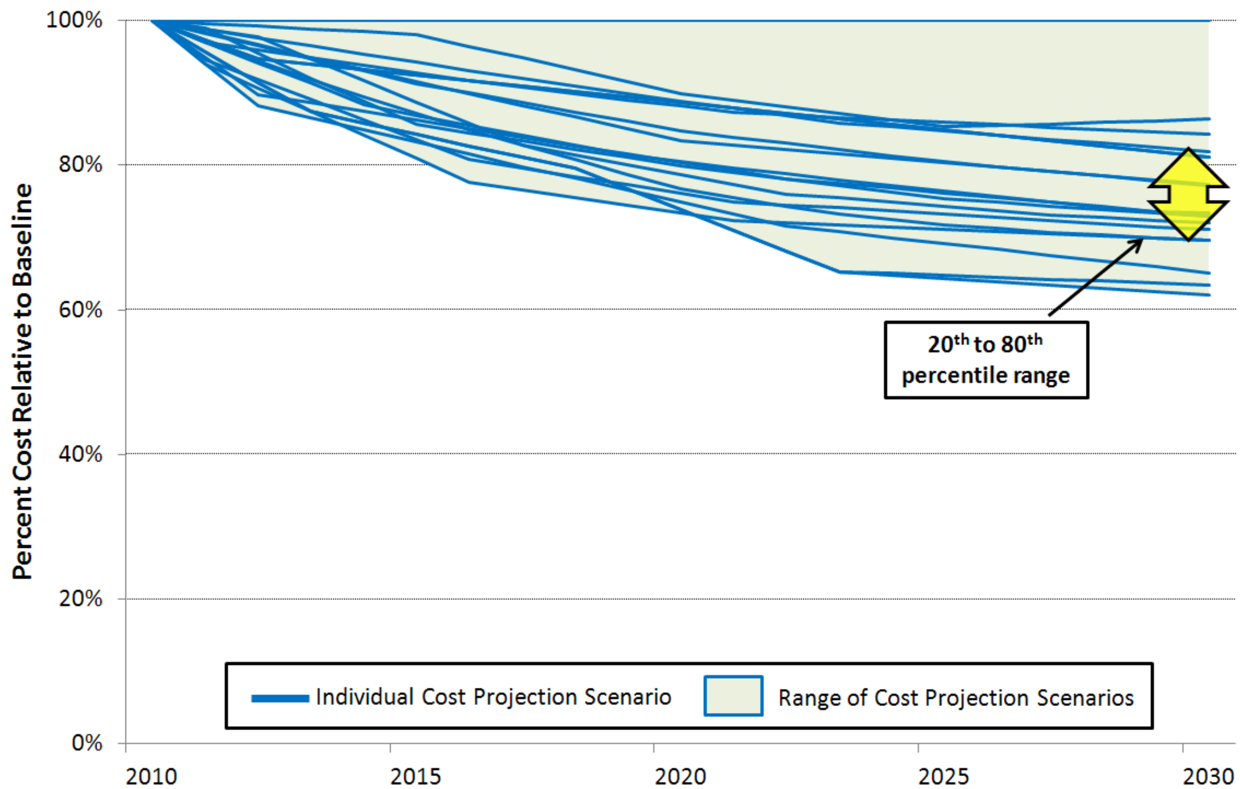

Figure 21. Estimated range of wind LCOE projections across 18 different land-based scenarios

Note: Due to the relatively small sample size (18 independent estimates) the 20th to 80th percentile range is approximated by excluding the four extreme high and low estimates.

Sources: EREC/GPI 2010, Tidball et al. 2010 (includes modeling scenarios from multiple other sources), U.S. DOE 2008, EIA 2011, Lemming et al. 2009, EWEA 2011a, EPRI 2010, Peter and Lehmann 2008, GWEC/GPI 2010, IEA 2009, and European Commission 2007.

To arrive at these values, individual study or scenario data were extracted and normalized to a common year (e.g., 2009) and a common currency value (e.g., U.S. dollars). From the normalized data, an estimated COE for each scenario was calculated. If the data were incomplete for a given scenario (e.g., only capital costs available), representative industry data were utilized for other parameters necessary to calculate COE. After calculating the annual percent reduction in COE, scenarios were aligned to a common starting point and annual percent reductions were applied for 20 years to estimate the expected reduction in COE between 2010 and 2030. Studies analyzed were dated between 2005 and 2010. Based on this relatively narrow and recent time frame, it was assumed that the drivers of specific cost-reduction trajectories remained available for integration into the average fleet turbine, and all projections were shifted to align in time, beginning in 2010.[19]

As summarized by Tidball et al. (2010), at least one scenario developed by the Environmental Protection Agency (EPA) assumes that the COE will remain flat with no improvements in cost or performance. The vast majority, however, project that costs will decline somewhere between 15% and 40%. Studies within the 20th to 80th percentile range (see Figure 21) anticipate COE reductions on the order of 20%–30%. Cost reductions are generally expected to be greater in the early years and then slow over time. Initial cost reductions range from roughly 1%–6% per year, falling to 1%–4% by 2020, and declining to 0%–1.5% by 2025. By 2030 all but one scenario envisions cost reductions falling to below 1% per year.

If the market forces continue to exert significant pressure on the cost of turbine equipment, the labor costs for installation and construction could be higher or lower than projected here. Potentially significant factors that are generally not captured in the studies include the impact of low-cost Asian turbines, increasing competition among manufacturers and engineers and procurement and construction contractors. These factors could either drive down industry margins and lower costs or renew upward pressure on commodity prices.

2.9.1 Sources of Cost Reduction for Land-Based Turbines

Although the future cost of land-based wind energy will be determined by both technical and market factors, a variety of technical drivers across the full turbine system are expected to exert downward pressure on the cost of energy (Table 15). New wind turbine design architectures, the use of advanced materials, and deployment of more sophisticated controls and sensing systems are expected to impact both turbine performance (i.e., increase energy production) and project costs. Because of the proportionally high cost of the wind turbine—70% to75% of the total capital costs (Wiser and Bolinger 2011) and 60% of the total lifetime project costs (Blanco 2009)—the bulk of innovation opportunities are focused on enhancing the turbine or its performance. Many of the technological advances noted below could also support reductions in the cost of offshore wind energy equipment.

[19] In some cases, new turbine models or existing prototypes may already include technology improvements that have been captured in various studies, suggesting that some portion of the cost reduction projection has already been realized. However, when thinking of the industry in terms of existing standard average fleet turbines rather than cutting edge, it is reasonable to assume that the cost of energy represented by the existing average fleet turbine has not incorporated the vast majority of the technology improvement opportunities that are assumed to be realized in these individual studies or modeling scenarios.

Table 15. Potential Sources of Future Cost of Energy Reductions in Wind Energy

R&D/Learning Area	Potential Changes (For additional detail on technology changes and expected impacts, see references below)	Expected Impact
Tower Concepts	Taller towers facilitated by use of new design architectures and advanced materials (Cohen et al. 2008, LaNier 2005, Malcolm 2004).	Reduced costs allowing access to stronger winds at higher above-ground levels
Rotor Concepts	Advanced controls reduce turbine loads allowing for larger and lighter rotors (Malcolm and Hansen 2006)	Increased energy capture with higher reliability and less rotor mass; reduced costs in other turbine support structures
Drivetrain Technology	Advanced drivetrain designs, reduced loads resulting from improved controls and condition monitoring (Bywaters et al. 2005)	Improved drivetrain reliability and lower drivetrain operating costs
Manufacturing Efficiency	Higher production volumes, increased automation (Cohen et al. 2008), on-site production facilities	Additional production based economies of scale, increased component consistency allowing for tighter design standards and reduced component weights, and reduced logistics costs
O&M Strategy	Enhanced condition monitoring and design specific improvements. Improved operations and routine maintenance strategies (Wiggelinkhuizen et al. 2008).	Real-time condition monitoring of turbine operating characteristics. Increased availability and more efficient O&M planning.
Resource Assessment	Turbine-mounted real-time assessment technology (e.g., LIDAR) linked to advanced controls systems. Enhanced array impacts modeling and turbine siting capacity (UpWind 2011).	Greater energy capture while reducing fatigue loads; allows for narrower design margins and reduced component masses as well as increased plant performance

Utilization of taller wind turbine towers can provide access to better wind resources, which increases annual energy capture. Under typical shear conditions, estimates by Cohen et al. (2008) indicate that taller towers have the potential to increase annual energy production by as much 11%. At present however, the added expense (primarily in steel, but also in turbine erection) of moving to taller tower heights is not economically justifiable, except for locations with higher than typical wind shear conditions (Wiser et al. 2012) (Figure 20). However, by employing advanced tower and rotor design concepts (Fingersh et al. 2006), steel content in the tower could potentially be reduced enough to allow higher hub heights to be achieved in a cost-effective manner across a wide array of wind resource conditions. Emerging changes in design architecture include hybrid (i.e., concrete and steel towers) and complete concrete towers. Application of advanced materials in tower design also provides potential innovation opportunities. Innovations targeted at reducing logistics constraints or providing self-erecting or partially self-erecting capabilities could simultaneously support reduced tower transportation costs further enabling the deployment of higher wind turbine towers.

Along with moving to higher hub heights, the development of larger rotor diameters may also increase the annual energy output of a given turbine. Cohen et al. (2008) estimate that foreseeable advancements enabling larger rotor diameters could boost energy production by as much as 10%–30%. The key to developing cost-effective larger rotors, however, lies in the ability to reduce rotor mass on a normalized basis (e.g., kg/m^2) while maintaining rotor energy conversion efficiency. Some weight reductions may be achieved by incremental design refinements and optimizations. To a great extent though, developing larger rotors with cost-effective weights will involve reducing rotor loads (Griffin 2001). To reduce rotor loads, more significant weight reductions might be achieved with designs that passively shed loads by twisting (Ashwill 2009) or that include partial blade span actuation coupled with sensing capacities. These would allow the rotor to adapt to variable wind conditions and turbulence in different parts of the rotor disk (Buhl et al. 2005, Lackner and van Kuik 2009). The development and application of trailing edge flaps that utilize LIDAR or comparable technology and sophisticated control systems that react to the wind that is moving toward the rotor (rather than the wind that has already passed) could also assist in reducing rotor loads and could reduce design minimums and ultimately rotor weight. Lower design minimums and rotor weight would facilitate the deployment of larger turbine rotors (Andersen et al. 2006, Berg et al. 2009).

There are two primary tactics that engineers and manufacturers are pursing to reduce the cost of wind turbine drivetrains. One tactic is to focus R&D efforts on optimizing current designs with the intention of increasing reliability and minimizing drivetrain weight (e.g., Peeters et al. 2006, Heege et al. 2007). A second tactic is for industry (including top tier original equipment manufacturers [OEMs]) to focus on continued development of new drivetrain designs (e.g., direct-drive turbines, single-stage medium-speed geared designs, and multigenerator architectures) (Cohen et al. 2008) with the intention of reducing operations and capital costs. Use of magnet generators has also become increasingly common in a variety of drivetrain platforms and offers the potential to effectively address weight and diameter or size challenges that have traditionally been associated with direct-drive designs. Again, based on foreseeable near-term innovations, Cohen et al. (2008) estimated that advancements in drivetrain design could result in an 8% efficiency gain and strategies that could reduce costs by as much as 11%.

Wind turbine manufacturing innovations may also result in variety of cost reductions. Tighter design tolerances enabled by the increased use of automated fabrication techniques that provide greater component consistency and uniformity will allow continued incremental reductions in weight and material use. Increased automation is also expected to yield greater reliability by minimizing material and component variances. Automated manufacturing processes will also increase production volumes, which will result in lower overall turbine costs (Cohen et al. 2008). Increased volume at specific sites or in relatively small regions coupled with advanced manufacturing strategies may also enable on-site production, which has the potential to dramatically lower logistics and transportation costs.

Widespread utilization of condition monitoring and the development of more optimized operation and maintenance strategies (e.g., enhanced planning for turbine downtime) are expected to minimize the impact of premature component failures and reduce operating period expenditures. Continued advancement of power electronics may also result in lower power conversion costs while increasing the ability of wind turbines to provide grid services.

2.10 Market Barriers for Land-Based Wind

A variety of deployment barriers can add uncertainty, lengthen project times, and raise the cost of wind development. The magnitude of these barriers may differ depending on the regulatory, environmental, and population characteristics of the region around a potential wind farm. These costs may be one-time payments (e.g., capital costs), or they may be recurring (e.g., operating costs). In addition, there may be explicit costs (e.g., permit fees) or implicit costs (e.g., the time lost due to regulatory hurdles). For example, factors such as local population density and regional wildlife habitats may require detailed environmental impact statements (EIS), which adds to the cost of obtaining a permit. After a wind project has been built, curtailment of power production may be required to reduce the impacts on humans and the environment, which may lower the annual capacity factor of the wind farm. Finally, the negotiation of transmission agreements and grid integration may be a costly and time-consuming process. Although not comprehensive, this list provides an adequate starting point for analyzing deployment barriers.

2.11 Permitting and Regulatory Requirements

Before building at a potential site, wind developers may be required to complete an environmental assessment (EA) or an EIS under the National Environmental Policy Act (NEPA); one of these is usually required for federal actions that impact the environment. State-level environmental protection agencies may require wind developers to complete the NEPA process even when no public lands are included in the wind farm. The NEPA process is designed to fully describe the environmental and social impacts of proposed actions. This typically involves input from several federal agencies, such as the U.S. Fish and Wildlife Service (USFWS), U.S. Forest Service (USFS), and the Bureau of Land Management (BLM). Further, because of their height, wind turbines have the potential to disrupt radar waves; therefore, wind developers must consult with the Federal Aviation Administration (FAA) and may have to consult with the U.S. military if located near military installations.

A recent European Union (EU) study found that the cost of conducting an EA in Europe can range between 0.01% and 2.56% of capital costs. Further, the study found that the average cost of an EA was around 0.5% of capital costs.[20] This suggests that EAs are relatively inexpensive compared to other capital costs. However, given certain conditions, such assessments may be difficult and time consuming. For a $150-million project, an average assessment in the EU may cost approximately $750,000. Although this cost is small when distributed over the life of the project, it is likely that wind developers will make siting decisions based in part on the ease of permitting. Given the choice of two competing locations, a developer may choose to move forward on the site with the fewest regulatory hurdles and the lowest potential for an extended NEPA process.

Even though the NEPA process is a relatively inexpensive component of development costs in many regions of the United States, the regulatory landscape for wind development is currently

[20] A study by the EU Environmental Commission found that 60%–90% of environmental assessment costs were incurred by carrying out environmental studies (http://ec.europa.eu/environment/eia/eia-studies-and-reports/eia-costs-benefit-en.htm). Although no recent studies have examined the magnitude of EIS costs in the United States, the EU study provides a reasonable starting estimate and we would expect costs to be similar.

uncertain, and these costs may increase. In January 2011, the USFWS released the *Draft Eagle Conservation Plan*, which greatly increases the time and cost of surveying and monitoring eagle activities at potential wind development sites. An analysis report funded by AWEA suggests that these costs may increase by fourfold to twelvefold.[21] If such projections are realized, these regulations have the potential to hinder wind development.

Although much attention is paid to the USFWS guidelines for eagle conservation, other jurisdictions may also have rules and regulations to prevent harm to sensitive wildlife populations and ecosystems. For example, San Miguel County, Colorado, has land-use codes that restrict the siting of wind turbines within Gunnison sage-grouse lek (mating) sites.[22] The Gunnison sage-grouse is not classified under the Endangered Species Act. However, it is considered locally to be a sensitive species, and wind developers are not allowed to disturb lek sites.

In addition to local environmental and wildlife restrictions, permitting may vary widely based on differing state and local building requirements. The installation of each wind turbine requires a building permit. The permitting fees and requirements may differ depending on the county or municipal building authority. To ease the wind permitting process, some states, such as Minnesota and Virginia, have attempted to streamline the regulatory process under one executive office, standardize permitting requirements, and set statewide flat permitting fees.

Finally, although the costs of permitting are usually relatively small compared to the overall project cost, they can also cause projects to be discontinued. If a project developer is unable to obtain a permit or does not comply with a specific regulation, the wind project cannot move forward and time and money spent on the project up to that point may be lost.

2.12 Increased Operating Costs

The issuance of wind farm permits may be contingent on regulatory, environmental, and social requirements. These requirements may increase operating costs or reduce the capacity factor of a wind farm, thus affecting the economic feasibility of developing a site. Further, wind farms are often required to maintain insurance in the event of an accident. Although regulations and requirements placed on wind farms may be necessary to ensure the health and safety of employees and local residents, meeting these regulations raises the costs of wind development. Unfortunately, current wind power literature lacks a complete cost analysis of these requirements. A thorough characterization of these requirements would prove useful in understanding wind farm operations.

As noted previously, wind turbines may affect wildlife (through bird and bat mortality and habitat disruptions) and local human populations (through nuisance factors such as shadow flicker, turbine noise, and obstructed view sheds). To mitigate these effects, wind farms may be required to curtail generation at certain times of the day or certain times of the year. The cost of curtailment is best characterized as the forgone profit that wind developers would have earned

[21] A Technical Review of the Draft Eagle Conservation Plan Guidance released by the USFWS, February 2011. Summary available at http://www.fws.gov/windenergy/eagle_comments/john_anderson.pdf.
[22] See San Miguel County Land Use Code section 5-319 H. III. g. iv (http://www.sanmiguelcounty.org/departments/planning/documents/Article5.2010.updated.pdf).

had they been allowed to operate the turbines. The scale of these forgone profits is not well understood and merits further analysis.

2.13 Transmission and Integration

Finally, wind development may be hindered by a lack of transmission infrastructure and difficulties integrating with the electrical grid. Generally, large wind farms are located far from highly populated areas, and thus require high-voltage power lines to transmit the electricity to demand areas. If a prospective wind farm is not located near high-voltage transmission lines, then developers may incur the added capital cost of building transmission lines so they may sell electricity to the grid.

Before wind power producers can sell electricity to the grid, they are required to conduct an integration study and negotiate a power-purchase agreement. Integration studies characterize how the addition of electricity from the wind farm will affect the electrical grid. Power-purchase agreements are long-term contracts to ensure a stable price of electricity. Both the integration study and the power-purchase agreement must be negotiated with electrical grid stakeholders such as power utilities, public utility commissions, and system operators. Conducting the integration study and the negotiations that follow may be costly and time consuming and have the potential to hinder wind development.

3 Offshore Wind

Schwartz et al. (2010) estimate that the gross domestic offshore wind resource is large enough to support more than 4,000 gigawatts (GW) of wind capacity, about four times the total installed capacity of all power generation in the United States (EIA 2011). Capturing even a small portion of that resource could have substantial economic impacts and reduce greenhouse gas emissions in the United States.

Although there is much enthusiasm about the potential of offshore wind in development and policy circles, no projects have been installed to date in U.S. waters. The lack of domestic experience with offshore wind technology has contributed to considerable uncertainty about the potential cost of offshore wind energy in the United States. This section offers an in-depth analysis of offshore wind cost trends in Europe as well as projections for the United States to develop baseline assumptions for a reference turbine in a commercial-scale offshore wind project. These baseline assumptions are used to estimate the levelized cost of energy (LCOE) for the reference project. This section describes the sensitivity of LCOE to various inputs and potential scenarios for future cost reduction.

Table 16 summarizes major inputs and LCOE analysis results, which are described in more detail in the following sections.

Table 16. Summary of Inputs and Results for Offshore Wind for 2010

	3.6 MW Offshore $/kW	3.6 MW Offshore $/MWh
Turbine Capital Cost	**1,789**	**62**
Balance-of-Station Costs	**2,918**	**101**
Soft Costs	**893**	**31**
Installed Capital Cost	**5,600**	**194**
Annual Operating Expenses	**107**	**31**
Fixed Charge Rate (%)	**11.8**	
Net Annual Energy Production (MWh/MW/yr)	**3,406**	
Capacity Factor (%)	**39**	
Total LCOE ($/MWh)	**225**	

3.1 Installed Capital Cost (ICC)

To date, no offshore wind projects have been deployed in the United States. This subjects any estimate about near-term installed capital costs to considerable uncertainty. For this research, multiple methods were used to develop a reliable near-term installed capital cost (ICC) estimate, including analysis of capital cost data for installed and planned projects in Europe and the United States, a review of recent literature on capital costs, and input from several leading U.S. project developers.

3.1.1 Trends in Offshore ICC (1991–2015)

Global installed offshore wind capacity reached approximately 3,285 MW in the second quarter of 2011 with the commissioning of the Baltic I (Germany) and the Walney I (United Kingdom) projects.[23] The NREL offshore wind project database (2012) contains capital cost data for 98% of the total installed capacity as well as estimates for 31 projects under development in Europe (~9,100 MW)[24] and 13 proposed projects in the United States (~3,700 MW). A number of projects have been proposed in Asia, but these are not included in this analysis because of the lack of available data.

Capital costs and project data were collected from a variety of sources including peer-reviewed literature, industry white papers, press releases, developer websites, and industry databases. Most cost estimates are self-reported figures from project developers and could not be independently verified.When there were multiple cost estimates for a given project, costs were

[23] This total does not include the partial grid connection of the BARD I project in Germany where 16 turbines, totaling 80 MW of capacity, were delivering power to the grid as of April 7th 2011 (NDR 2011).

[24] Cost data for European projects have been limited to those that have obtained regulatory approval by the relevant authority. Projects still in the permitting process have been excluded as their cost estimates are likely less mature.

averaged. Cost data were inflated in the original currency and then converted to 2010 U.S. dollars.[25]

The precision of the dataset is subject to a few key limitations:

- Reported costs are generally rounded estimates and not actual realized or quoted costs.
- Few sources identify the categories of costs included in their estimates, making it difficult to ascertain whether reported costs fully reflect the total cost of installing the project and connecting it to the grid.
- A number of capital cost estimates date from before 2009 and might not reflect the current cost expectations of project developers.

Figure 22 shows the estimated installed capital cost per kilowatt for 86 installed and planned offshore wind projects in Europe and the United States.

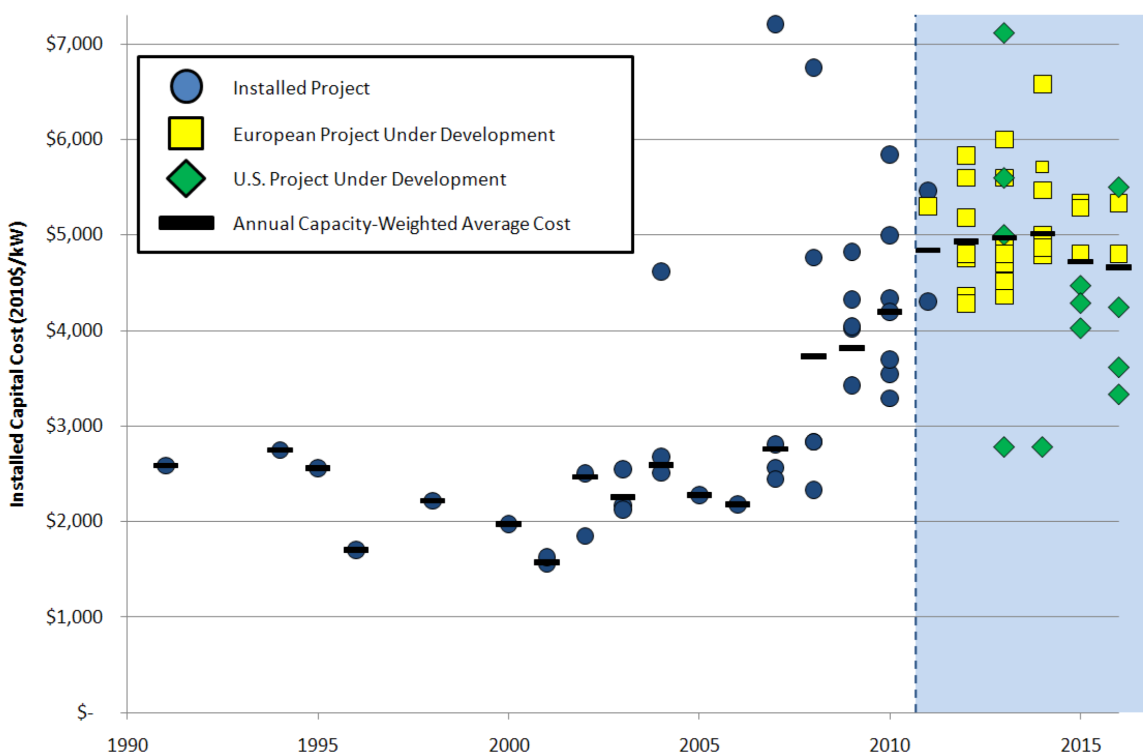

Figure 22. Offshore wind project ICC per kilowatt

Figure 22 illustrates the evolution of offshore wind project capital costs in the 20-year period between the installation of the first project in 1991 and the most recent projects installed in 2011. Projects shown here represent 98% of total installed offshore wind capacity in 2010 in real dollars. Offshore wind projects installed between 2000 and 2007 had a weighted average cost of

[25] 1 EUR = 1.400 USD, 1 GBP = 1.618 USD, 1 DKK = 0.188 USD, 1 SEK = .157 USD, 1 NOK = 0.179 USD (x-rates.com 2011)

$2,431/kW. Costs have nearly doubled since then; projects installed between 2008 and 2010 averaged $4,002/kW, and projects installed in 2010 averaged $4,195/kW. The UK Energy Research Center (UKERC 2010) and Deloitte (2011) have performed detailed analyses of the drivers behind these increasing costs. The figure also plots announced costs for projects under development in Europe and the United States to show current developer expectations about cost trends for near-term projects. The figure shows considerable scatter with costs ranging from about $2,500/kW to more than $7,100/kW. The weighted average cost for all projects with expected commissioning dates between 2011 and 2016 is $4,862/kW, suggesting that developers expect project costs to stabilize. However, this might just reflect the use of current assumptions to inform expectations about future cost trends.

In an industry with such rapidly changing costs, projections of future project costs would be expected to be largely dependent on the developer's understanding of the prevailing cost environment around the date of announcement. Figure 23 shows offshore wind project costs at the date of announcement and compares them to the capacity-weighted average cost of actual projects installed in each year.

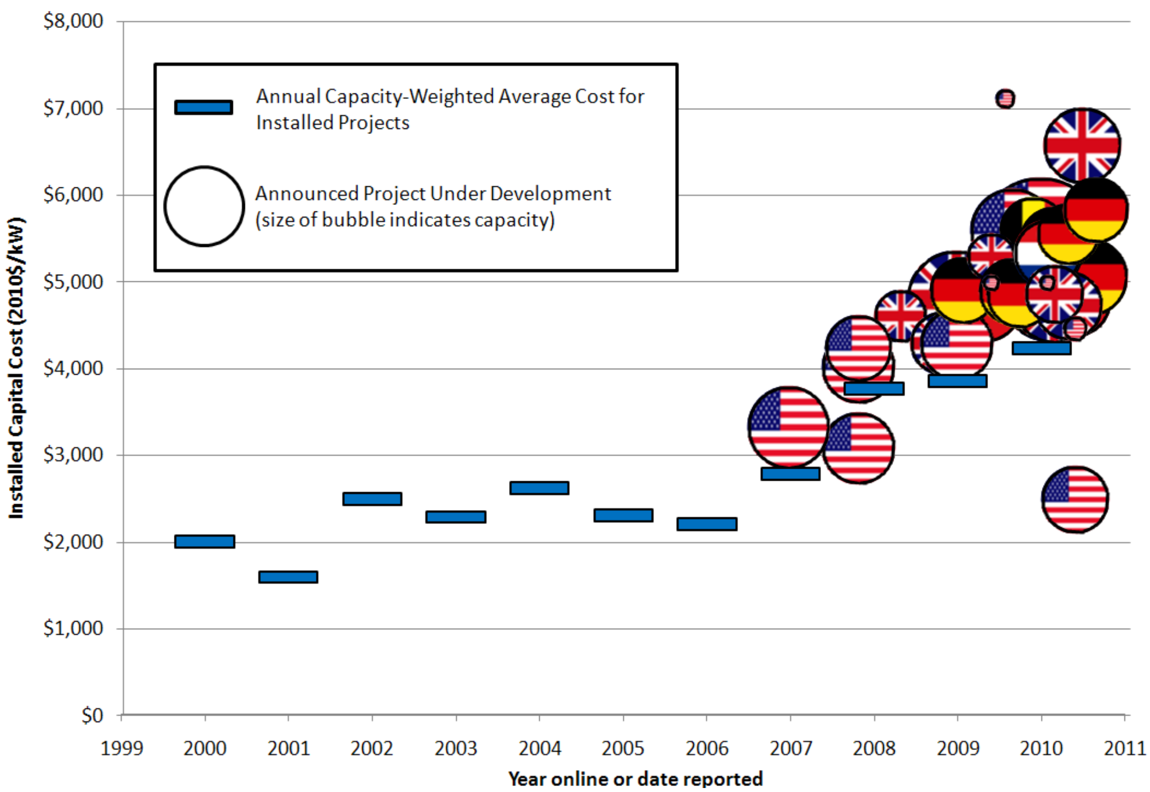

Figure 23. Offshore wind project ICC per kilowatt by date reported

Projected costs for planned projects appear to closely follow cost trends for installed projects. The data shown by date of announcement are much less scattered with much greater temporal consistency. The clear low projection to this trend is a 300-MW project in Texas. It falls nearly $2,000/kW below any other estimate reported in 2010 and may not be representative of offshore wind projects in the United States, using European-based technology and assumptions.

Steadily increasing cost projections suggest that near-term project costs are probably best predicted through analysis of projects that have been announced recently. A more restricted selection of projects is developed to estimate the future cost of commercial-scale offshore wind projects using the following criteria:

- Capital cost estimate reported or revised after January 1, 2010
- Exclusion of pilot projects (<50 MW)
- Exclusion of projects that have not yet announced a firm turbine supplier

The restricted dataset includes 29 projects totaling 8,330 MW of capacity. The only project in the United States that meets the criteria for inclusion is Cape Wind and, therefore, projections of capital cost generated from this dataset are heavily biased toward the expectations of European developers.

Figure 24 shows the fitted capital cost distributions for three categories of offshore wind projects under development: all projects, U.S. projects, and restricted datasets. Best fit was achieved with a normal distribution for the all-projects dataset and with a lognormal distribution for the U.S. projects and restricted datasets.

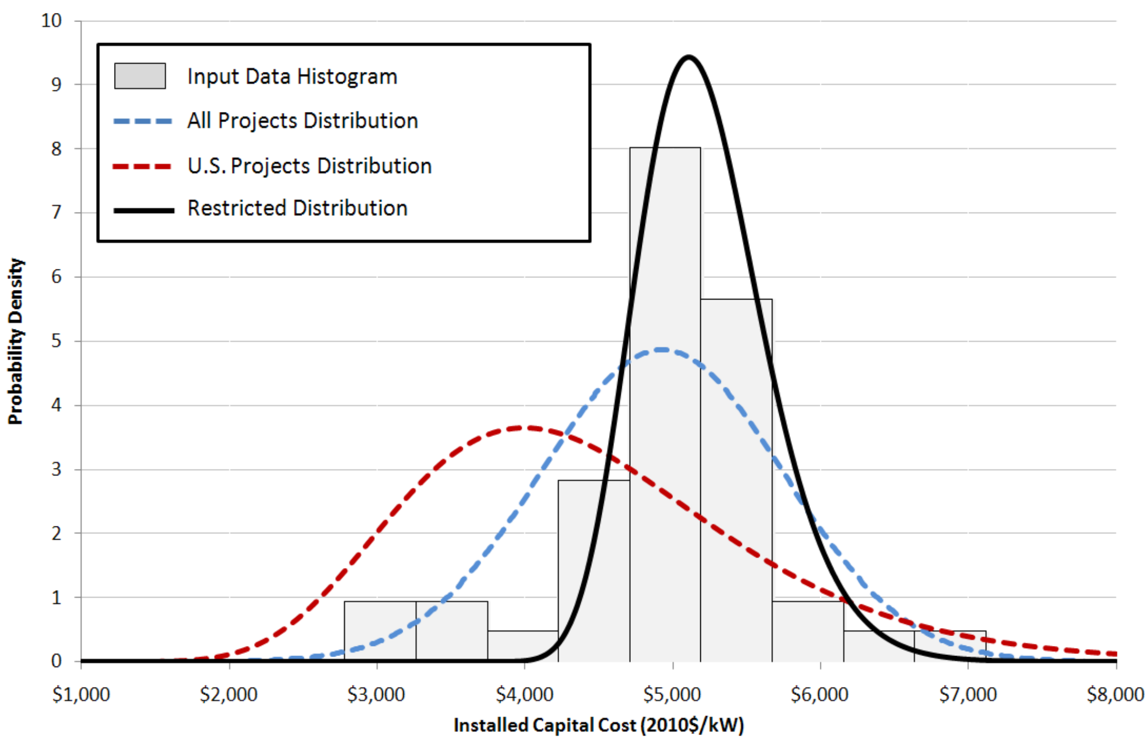

Figure 24. ICC distributions for all projects, U.S. projects, and restricted datasets

In general, recent cost estimates are both more expensive and more uniform than either of the other datasets. The weighted-average capital cost for the restricted dataset is $5,120/kW with a standard deviation of $498/kW. The 13 proposed projects in the United States have a much lower weighted-average cost at $4,460/kW with a much wider cost distribution (standard deviation $1,255). The following two possibilities are offered to help explain this trend:

1. No projects have been installed in the United States. The lack of a benchmark project leads to uncertainty around probable investment costs, cost drivers, and potential risks. Uncertainty could be driving the wide variation in the investment cost estimates of U.S. developers.
2. The cost estimates for many U.S. projects were reported before 2009 and might not reflect the current expectations of developers. Cost estimates that were reported or revised in 2010 and 2011 average[26] \$5,520/kW versus \$3,600 for announcements made in 2009 or before. This difference in the timing of these estimates likely distorts the dataset.

These observations suggest that the average cost of near-term offshore wind projects in the United States will be much closer to the \$5,120/kW estimate derived from the restricted dataset than to the \$4,460/kW average reported cost for proposed projects in the United States.

3.1.2 ICC Literature

A number of recent studies have developed estimates of the near-term investment costs of offshore wind projects. The studies employed a variety of methodologies to estimate near-future capital costs. The European Wind Energy Association (Krohn et al 2009) and Krogsgaard (2010) developed estimates using actual investment costs for realized projects. Ernst & Young (2009), Musial et al. (2010), the Energy Research Centre of the Netherlands (ECN) (Lako 2010), the Research Council of Norway (RCN) (Douglass-Westwood 2010), and Deloitte (2011) developed cost estimates through examination of historic trends and analysis of publicly available cost data for near-term projects. Garrad Hassan (2009) and consulting firms KPMG (2010), Mott Macdonald (2010), Ove Arup (2011), and BVG Associates (2011) developed estimates using a mix of publically available data, direct surveys of active project developers, and confidential tender submissions. The Energy Information Administration (EIA 2011) commissioned an external consultant to develop current cost estimates for a generic, utility-scale offshore wind project installed in 2015. Estimated costs were inflated in the original currency and converted to 2010 dollars (See Footnote 25). Figure 25 shows the range of capital cost estimates developed for each study and the average or "best guess" estimate of likely project costs within each range.

[26] Averages are weighted by project capacity.

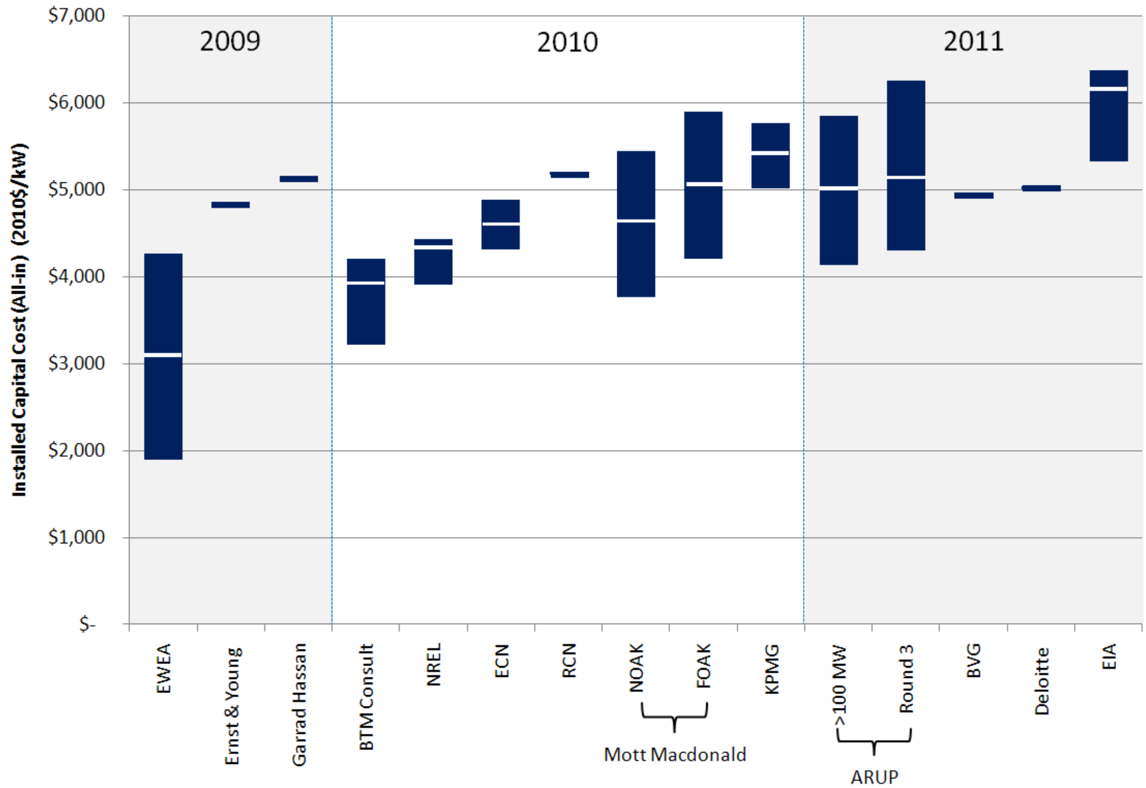

Figure 25. Range and representative ICC estimates in recent literature

Figure 25 show that capital cost estimates range from a low of about $2,000/kW to a high of more than $6,350/kW. The average of the "best guess" estimates is $4,832. If the sample is restricted to the studies that use a forward-looking methodology, the average increases to $5,048/kW.

3.1.3 Near-Term Offshore ICC in the United States

Although the data discussed above provide a good overview of the likely costs of offshore wind projects in Europe, the extent to which those data will apply to projects in the United States is uncertain. NREL reviewed the documents associated with the recent power-purchase agreement (PPA) filings for the Cape Wind and the Block Island Wind Projects. NREL also initiated discussions with several developers to gain an understanding of the specific, component-level capital costs that they expect to incur as well as the assumptions behind those costs.

A review of the data sources outlined above suggest that utility-scale offshore wind projects in the United States[27] are generally expected to cost between $5,000/kW and $6,000/kW, with a bias toward the higher end of this range. The PPA for Cape Wind, the most advanced utility-scale offshore wind project in the United States, is based on an installed capital cost of $5,600/kW (MDPU 2010).

Planned projects are located between 10 kilometers (km) and 50 km from shore, in water 10 m to 30 m deep, and used 3- to 6-MW turbines on either monopile or multiple foundations. Limited

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[27] This discussion excludes the Galveston Wind Project because it is probably not representative of the cost of offshore wind projects installed off of the North or Mid-Atlantic coast of the United States.

data prevent meaningful statistical analysis of the impacts of any of these variables on total capital costs.

Developers noted that capital cost estimates include contingencies of between 5% and 10% to manage cost uncertainties and overruns. This is consistent with KPMG (2010), which found that German developers generally size contingency reserve funds to cover about 10% of hard capital costs. Figure 26 represents a range of U.S. proposed project ICC and the baseline capital cost for near-term projects in the United States.

The installed capital cost baseline for 2010 is $5,600, which is consistent with the assumption published in Cape Wind's PPA and within the range suggested by data collected from the literature and other leading developers. The range of capital cost shown in Figure 26 extends from $2,500/kW to $6,500/kW to reflect the range of cost data for near-term offshore wind projects in the NREL project database.

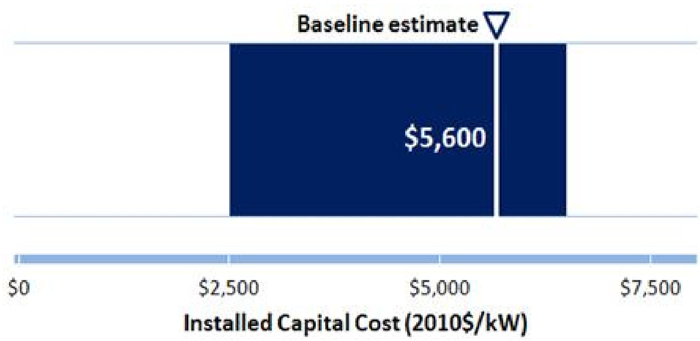

Figure 26. Offshore ICC range and NREL baseline

Figure 27 shows the percentage contribution of each component to total capital cost for the baseline offshore wind project. Percentage estimates are based on NREL's Wind Turbine Cost and Scaling Model (Fingersh et al. 2006, Maples et al. 2010), several recent publications (Douglas-Westwood 2010, BVG 2011, Deloitte 2011), and conversations with offshore wind project developers in the United States. The segment in green represents the turbine cost, shades of blue represent balance-of-station costs, and shades of purple represent soft costs.

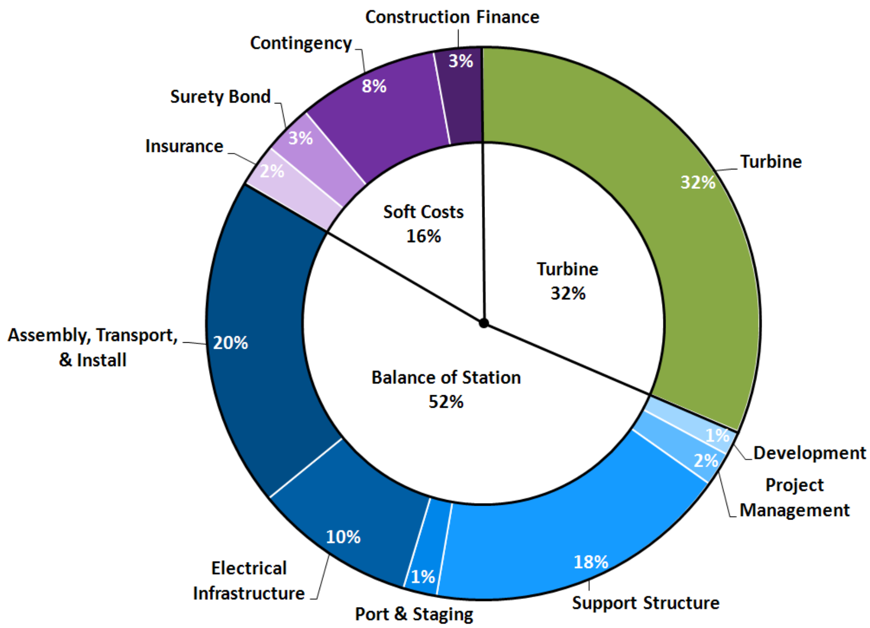

Figure 27. Installed capital costs for the 2010 offshore wind reference turbine

These percentage estimates were applied to the all-in capital cost estimate of $5,600/kW to generate individual component costs in dollars per kilowatt for the 2010 baseline project. This dollar-value component cost breakdown is shown in Table 17.

Table 17. Offshore Wind LCOE Component Cost Breakdown

	3.6-MW Offshore $/kW	***3.6-MW Offshore*** $/MWh
TURBINE CAPITAL COST	**1,789**	**62**
Development (permits, engineering, site assessment, etc.)	58	2
Project management	117	4
Support structure	1,021	35
Port and staging	73	3
Electrical infrastructure	540	19
Transportation and installation	1,109	38
BALANCE OF STATION	**2,918**	**101**
Insurance	94	3
Surety bond (decommissioning)	165	6
Contingency	471	16
SOFT COSTS	**730**	**25**
OVERNIGHT CAPITAL COST (OCC)	**5,437**	**188**
Construction financing cost	163	6
INSTALLED CAPITAL COST (ICC)	**5,600**	**194**

Any capital cost estimate for offshore wind projects can be considered very time dependent in that the estimated value will vary from year to year to reflect current market conditions. Several recent, interrelated trends, including the global recession, reduced commodity prices, and the slowdown in the U.S. land-based wind industry, have put significant downward pressure on costs for land-based wind projects. This is illustrated in a recent report by Wiser and Bolinger (2011), which shows that the price of turbine supply agreements announced in 2010 have dropped by about $500/kW from peak prices in 2008. Prices for offshore wind turbines may experience a similar drop, leading to potentially large reductions in capital cost. In-depth discussion of potential capital cost improvements and the impact of such improvements on LCOE can be found in Section 3.7.

3.2 Annual Operating Expenses (AOE)

Annual operating expenditures for offshore wind projects are subject to even greater uncertainty than installed capital costs for two reasons: (1) no projects have been installed in the United States, and (2) project owners in Europe do not generally report these costs. This uncertainty is amplified because most utility-scale projects are still covered by warranties. It is standard practice in the offshore wind industry for original equipment manufacturers (OEMs) to offer 5-year warranties with their turbines, meaning that only projects installed before 2006, or just 20% of installed capacity, are subject to the full range of operating costs. Operation and maintenance costs is site dependent and will vary significantly depending on factors such as depth, distance to shore, and prevailing sea and weather conditions (UKERC 2010).

AOE for offshore wind projects in the United States are broken down into three major categories: (1) levelized replacement cost (LRC) captures the anticipated costs of replacing major components (e.g., blades and generators) over the project lifetime; (2) operations and maintenance (O&M) costs include the labor, vessels, equipment, scheduled maintenance, unscheduled maintenance, onshore support, and project administration required to manage the project and ensure generation; and (3) the outer continental shelf (OCS) lease, which is a levelized representation of annual lease payments to the Bureau of Ocean Energy Management, (BOEM).[28]

3.2.1 Operating Cost Literature

A number of recent publications have attempted to estimate operating costs for near-term offshore wind projects. As with the capital cost literature, these studies used a variety of methodologies. Krohn et al (2009) and ECN (Lako 2010) developed estimates based on historical experience at installed projects. Ernst & Young (2009), KPMG (2010), Salvadores (2010), Mott Macdonald (2010), and Ove Arup (2011) developed estimates using a mix of publically available data and direct surveys of active project developers. It is unclear how Cape Wind (MDPU 2010) estimated its operating costs, but it is likely that they are based on the experience and expectations of project partners including Siemens. These studies report operating costs, but do not break costs down into LRC, O&M, and OCS. Figure 28 shows the range of operating cost estimates developed for each study and the average or "best guess" estimate for likely costs within each range. Cost data reported in cost per megawatt per year were

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[28] Lease payments are expected to range between 2% and 7% of operational revenue. Cape Wind 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 2010).

converted to cost per megawatt-hour using the internal assumptions outlined in each study or scenario. Estimated costs were inflated in the original currency and converted to 2010 dollars.

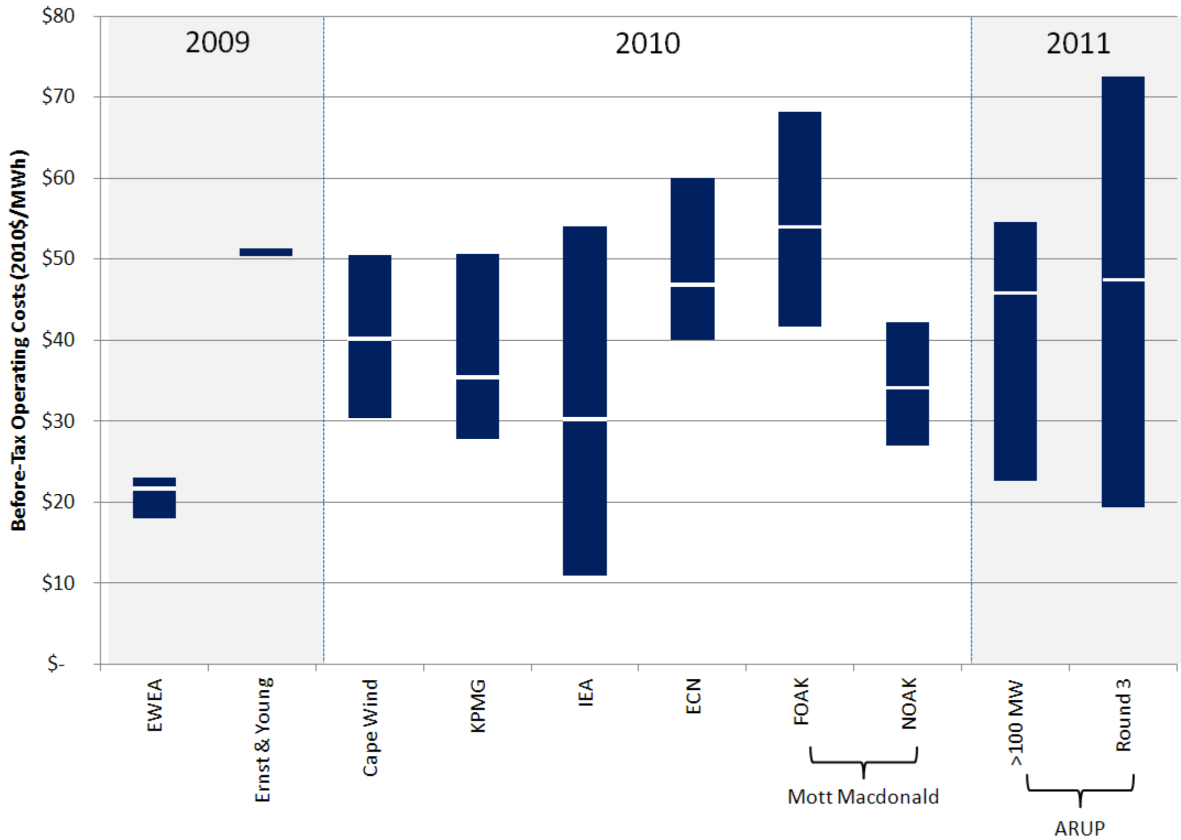

Figure 28. Range and "best guess" operating cost estimates in recent literature[29]

Figure 28 shows projections of near-term operating costs ranging from about $10/MWh to more than $70/MWh. The average of the "best guess" estimates is $40/MWh. To convert the before-tax operating cost estimates to after-tax AOE, we account for the tax deductibility of O&M expenses. This conversion yields an average of $31/MWh and a range extending from $9/MWh to $55/MWh.

3.2.2 AOE for Offshore Wind Projects in the United States

NREL's conversations with developers suggest a range of AOE between $20 and $39/MWh, which is similar to the range of costs reported in the literature. The AOE baseline for 2011 is assumed to be $31/MWh based on a "best guess" from collected data, which is equivalent to $107/kW/yr. AOE costs are assumed to range from $15 to $55/MWh derived from a survey of the literature (See section 3.2.1) and survey of U.S. developers (See section 3.2.2). The high end estimate of $55/MWh is approximate of high-end values in the UK, as reported by Mott, Macdonald, and ARUP.

[29] The ARUP report categorizes the cost of transmission as an operating cost to reflect the OFTO program in the U.K. These costs, which amount to about $110/MW/year, have been removed for comparative purposes.

Figure 29 shows the range of annual operating expenses and NREL's baseline annual operating expense for near-term projects in the United States. The equivalent range on a $/kW/yr basis extends from $51 to $187/kW/yr.

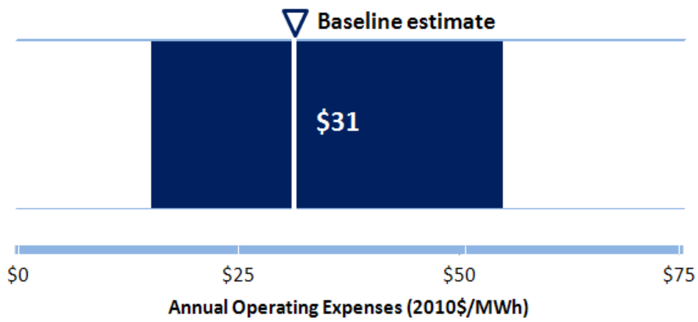

Figure 29. AOE range and NREL baseline for near-term U.S. projects

3.3 Annual Energy Production (AEP) and Capacity Factor (CF)

Gross annual energy production (AEP) is determined by measured wind speed at the project site and the power curve of the planned turbines. Production delivered to the grid is reduced by the array shadowing (wake effect), availability for power generation, turbine power consumption, and transmission line losses. These impacts are subtracted from gross AEP to identify the net or actual AEP. The ratio between the theoretical AEP (100% load factor) and the net AEP over a certain period, generally one year, is referred to as the net capacity factor.

Wiser et al. (2011) report that installed European offshore wind projects typically achieve capacity factors of between 35% and 45%. Rødsand II, a Danish project installed in 2010, reported a capacity factor of 55% in its first year of operation. Developers in the United States have announced capacity factor expectations for nine project sites currently under development. Net capacity factors at these projects range from 32% to 42% with an average of 38% (NREL Project Database 2011).

Because net AEP and the corresponding net capacity factor will vary with the wind resource and project design, NREL assumes specific site characteristics for the baseline offshore wind project (see Section 3.7). AEP for this analysis was calculated using the NREL Cost and Scaling Model and a class-6 wind resource (Fingersh et al. 2006). Wind resource characteristics are discussed in more detail in Section 2.4. Table 18 shows the assumptions used to calculate AEP at the baseline project.

Table 18. Offshore Turbine Baseline AEP Input Assumptions

	Offshore 3.6 MW
Turbine rotor diameter (m)	**107**
Turbine hub height (m)	**90**
Annual average wind speed @ 50 m (m/s)	**8.4**
Weibull K	**2.1**
Shear exponent	**.1**
Rotor peak Cp	**.47**
Maximum rotor tip speed (m/s)	**90**
Tip-speed ratio (TSR) at max Cp	**8**
Non-drivetrain losses (%)	**15**
Availability (%)	**96**
Drivetrain design	**Geared**

NREL assumes that offshore wind projects will experience losses from array impacts, availability, and inefficiencies in power collection and transmission. Losses are estimated for offshore wind projects using commercially available technology and with the NREL Cost and Scaling Model. Table 19 shows the impact of losses on AEP and capacity factor.

Table 19. Offshore Turbine Net AEP and CF

	Offshore 3.6 MW
Gross AEP (MWh/MW/yr)	**4174**
Gross capacity factor (%)	**48**
Losses & Availability (%)	**18**
Net AEP (MWh/MW/yr)	**3,406**
Net capacity factor (%)	**39**

Table 19 shows that the 2011 baseline project will deliver 3,406 MWh per MW of installed capacity annually, which is equivalent to a net capacity factor of 39%. It is possible that the first projects will have lower availability than expected, resulting in lower net capacity factor than is assumed in this analysis.

Figure 30 shows the baseline assumption of a 39% capacity factor and a range of 30%–45% for possible capacity factors for offshore wind projects in the United States. The corresponding baseline AEP will be 3,406 MWh/MW/year with a range extending from 2,600 to 3,950 MWh/year.

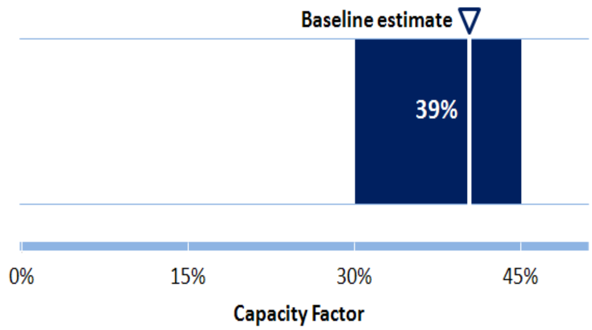

Figure 30. Capacity factor range and NREL baseline

3.4 Finance

Offshore wind projects are capital intensive with utility-scale projects (>200 MW) requiring investments of more than $1 billion. Rapidly changing project economics and limited experience have made private investors hesitant to commit significant capital to offshore wind projects.[30] These characteristics suggest that one of the main near-term challenges for developers will be to attract affordable financing for project portfolios.

Risks are becoming better understood in Europe with increasing capacity additions and the expansion of project finance (Guillet 2011). Still, the availability of capital remains a key challenge in these markets, and European governments have introduced or modified programs to attract private investors to the offshore wind sector. The initial offshore wind projects in the United States will benefit from the experience developed in Europe, but will face a significantly more uncertain risk proposition until projects are realized and the regulatory and policy environment become more certain.

3.4.1 Overview of European Trends in Offshore Wind Finance

Offshore wind projects in Europe have historically been financed on the balance sheets of large utilities. The ability of these traditional utility sponsors to expand balance sheet financing of offshore wind projects while maintaining their debt rating is somewhat limited. Most industry commentators expect that non-recourse financing[31] will have to expand if the European nations are to meet the 40 GW by 2020 offshore wind deployment targets outlined in the National Renewable Energy Plans (Bloomberg 2011, Talagrand 2010).

Only three installed projects were financed with non-recourse debt prior to construction, totaling 315 MW or about 10% of installed capacity. An additional three projects under construction have secured non-recourse debt. These projects total about 925 MW or nearly 30% of current

[30] Uncertainty about the probability and impact of risks on cash flows diminishes investor confidence that a given project can deliver the required rates of return.
[31] Non-recourse finance or project finance refers to a loan where the lending bank(s) is only entitled to repayment from the profits of the project that the loan is funding. The lending bank(s) do not have any claim on the assets of the borrower.

capacity under construction but have not yet started construction. Additionally, the 288-MW Meerwind project in Germany recently closed financing. Table 20. Non-Recourse Finance Activity in the Offshore Wind Sector summarizes project finance activity[32] in the offshore wind sector to date (Claveranne 2011, Mckenna 2011, and Bloomberg 2011). Funding amounts were converted to U.S. dollars using the prevailing exchange rate at the date of financial close, and the debt rate is nominal. The amount of debt does not include contingency budgets, and the term of the debt is shown from the date of commissioning (some deals include lead times for the construction period). The cost of debt (rate) is shown in basis points (bps) over the London Interbank Offered Rate (LIBOR).[33]

Table 20. Non-Recourse Finance Activity in the Offshore Wind Sector

Project	Country	Capacity	Amount (USD)	Rate (bps)	D:E Ratio	Tenor	Status
Princes Amalia (Q7)	Netherlands	120 MW	$257 M	<200	53:47	9.5y	Installed
Thornton Bank I	Belgium	30 MW	$129 M	<150	63:37	15y	Installed
Belwind I	Belgium	165 MW	$606 M	<300	69:31	15y	Installed
Thornton Bank II & III	Belgium	325 MW	$1,157 M	<300	68:32	15y	Construction
Borkum West II	Germany	200 MW	$602 M	<200	59:41	15y	Construction
Global Tech I	Germany	400 MW	$1,466 M	<300	81:19	NA	Construction
Meerwind	Germany	288 MW	$1,166 M	<300	69:31	15y	Approved

Total non-recourse funding for the offshore wind sector amounts to more than $4 billion, with rates ranging from less than 150 bps to more than 300 bps. Loan maturity ranges from 9.5 to 15 years after project completion and generally reflects the period for which pricing is guaranteed.

All of the projects shown in Table 20 were guaranteed a price for generated power through feed-in tariffs (FiTs). Six of the seven completed deals include the participation of a public financial institution (PFI) and/or an export credit agency (ECA) as an investor or a provider of guarantees. PFIs and ECAs help to limit the exposure of private investors to the risk of building and operating projects offshore. Governments are increasingly using these programs to attract private capital to the offshore wind industry (Claveranne 2011).

Table 21 shows the public institutions that are participating or are expected to participate in the market (EIB 2010, Euler-Hermes 2011, KfW 2011, NIB 2011, Harvey 2011).

[32] The table does not include refinancing deals for operating offshore wind projects (North Hoyle, Lynn and Inner Dowsing, and Baltic I) because investors in these deals were not subject to construction risk.
[33] A basis point is a unit of measure equal to 1/100th of 1%.

Table 21. Public Institutions Involved in Offshore Wind Project Finance

Institution	Country	Type	Mandate	Experience
European Investment Bank (EIB)	EU	PFI	Funds projects that promote EU objectives including climate change mitigation. $4.2 B funded or approved for offshore wind	Belwind, Thornton Bank II & III, Borkum West, Global Tech I.
Eksport Kredit Fonden (EFK)	Denmark	ECA	Supports export of Danish products with loans and guarantees	Q7, Belwind, Thornton Bank II & III, Meerwind
Euler-Hermes	Germany	ECA	Guarantees to support export of German products, particularly renewable energy	Thornton Bank II & III
KfW Bankengruppe	Germany	PFI	Program to finance initial offshore wind projects in Germany. Budget = $7 B	Global Tech I, Meerwind
Nordic Investment Bank (NIB)	DK, EE, FI, IS, LV, LT, NO, SE	PFI	International finance institution of Nordic & Baltic countries; funds projects that strengthen competiveness of member countries and/or enhance the environment	Anholt, Horns Rev I, Horns Rev II, Nysted, Rødsand II
Green Bank	United Kingdom	PFI	Finances green infrastructure projects in U.K. including offshore wind. Budget = $5 B	2012 Launch

The participation of these public institutions represents a major source of capital for the European offshore wind projects and will likely be an integral component of any near-term non-recourse debt structures. It is also highly probable that ECAs will be active investors in U.S. offshore wind projects as these could potentially offer a large market for exported products and services.

3.4.2 Overview of U.S. Trends in Offshore Wind Finance

Several recent developments in the United States could have an impact on the financial viability of the initial offshore wind projects in the United States.

- The U.S. Department of Energy's (DOE's) Loan Guarantee Program (LGP) has been placed on hold due to uncertainty about future allocations from the U.S. Congress. This development was a major setback for the offshore wind industry, as the LGP seemed to present the most viable option for attracting affordable financing to the first projects. The program, through guaranteeing payment of up to 85% of the debt, would limit investor exposure to the uncertainties of installing and operating a project, conceivably enabling developers to obtain non-recourse financing. The cancelation of the program has already had ramifications for the industry; Bluewater Wind cited this event as the key driver of a decision to delay construction of a met tower at its proposed Delaware site (Del Franco 2011).
- After news that Cape Wind would not receive a loan guarantee, Siemens, the turbine OEM, announced that it would be willing to invest both debt and equity in the project (Wingfield 2011). The involvement of OEMs in project finance could offer a way forward for the initial offshore projects in the United States, though it is too early to tell if this will be a trend. Foreign OEM investments will likely be accompanied by loans or guarantees from ECAs.
- The three major federal incentives for wind power, the production tax credit (PTC), the investment tax credit (ITC), and the Section 1603 Cash Grant are all set to expire

for wind applications in the near-term (AWEA 2011). These incentives are considered to be essential to the financial viability of wind projects and the specter of expiration creates considerable uncertainty for investors. Without action to extend these programs, investors are not likely to pursue investment in any projects with online dates beyond 2012.

- Legislation by state governments aimed at supporting the development of the offshore wind industry looks to be the near-term driver of financial viability. New Jersey has introduced a measure to obtain 1% of its electricity from offshore wind. Delaware has established a renewable energy certificate (REC) multiplier for offshore wind projects, and Rhode Island and Massachusetts both intervened on the behalf of offshore wind developers during the regulatory review of PPAs (Wilner 2010, Mancinho 2010, DSIRE 2011a, DSIRE 2011b). These actions will help to boost the viability of offshore wind projects in these states through the creation of additional, high value revenue streams—RECs or Offshore Renewable Energy Credits (ORECs)—or the guarantee of fixed, above-market prices for delivered energy.

3.4.3 Risk and Description of Risk Factors

No offshore wind projects have been installed in the United States and this 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 one of the key barriers to the implementation of planned projects (Lannard 2011).

Table 22 outlines risk categories, gives specific examples, and the lists mitigation strategies that developers are adopting (Guillet 2007, Tassin 2010, Mous 2010, Claveranne 2011).

Table 22. Offshore Wind Project Risks and Mitigation Strategies

Risk Category	Description / Examples	Example Mitigation Strategies
Development Risks	• Project viability – Permits – Power off-take (grid connection) – Sufficient capital for development • Limited to equity (financing arranged after permits are secure)	• Community engagement • Robust project management • Sponsor commitments • Due diligence to ensure that all permits licensees, authorizations are in force
Finance Risk	• Attract sufficient debt/equity capital to cover project investment costs • Once operational, revenue must cover payment obligations	• Planning, engaging likely financiers early • Diligent permitting/contract structuring • Fixed price for generated power • Conservative, validated estimates
Construction Risks	• Delays and cost over-runs – Currency risk/commodity price risk – Severe weather – Contractor delays – Accidents • Responsibility for problems – No EPC wraps for offshore wind – Multiparty contracts have interface risk	• Analysis of downside scenarios • Preparation of contingency fund • Insurance • Strong contracts – identification of interfaces and clear allocation of responsibility • Due diligence to validate design, engineering, planning and management team

Risk Category	Description / Examples	Example Mitigation Strategies
Operations Risk	• Lower availability – Turbine accessibility – Vessel availability – Limited operational experience with new turbines • Cost overruns – Accidents leading to cable damage – Serial design flaws in early projects (ex. monopile grout) – New turbine technology (5 MW+) – Limited long-term track record	• Smart warranty design with emphasis on revenue protection • Long-Term Service Agreement (LTSA) • 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 off-take contract – Market volatility	• Fixed price contract (PPA or FiT) • Conservative projections

As offshore wind projects are implemented in Europe, investors are using lessons learned to develop effective strategies to manage their risk exposure. European governments are helping 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 appears effective; EWEA (2011b) reports that more than 20 financial institutions have obtained internal approval to accept offshore wind project risk.

The lack of installed offshore wind projects in the United States creates substantial uncertainty about the ability of the nascent industry to deliver projects within the planned budget as well as the treatment of offshore wind projects under the untested U.S. regulatory framework. The lack of experience means that investors cannot, with any 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 will limit their enthusiasm to commit unsecured capital to the initial offshore wind projects.

3.4.4 Financing Rates for Offshore Wind Projects in the United States

The first offshore wind projects in the United States will almost certainly require a fixed-price PPA to be financially viable. The costs of offshore wind projects exceed market prices and, therefore, cannot compete with more established technologies on the wholesale market. Under these conditions, sponsors and lenders will require the guarantee of a price for generated power before they are willing to move forward with the substantial capital investment required to build an offshore wind project.

To date, developers and utilities have negotiated three offshore wind PPAs: 1) Bluewater Wind and Delmarva negotiated a PPA for 200 MW in 2008, 2) Cape Wind and National Grid negotiated a PPA for 264 MW in 2010, and 3) Deepwater Wind negotiated a PPA for 29 MW in 2010. The terms of these PPAs are summarized in Musial and Ram (2010).

The above market prices of the Cape Wind and Deepwater Wind PPAs drew a number of legal challenges and led to the renegotiation of contracts in the Massachusetts Department of Public Utilities and the Rhode Island Public Utilities Commission. In both cases, the developers agreed to open their books to the regulators, accept a limit to the rate of return that they could earn on the project (~10.5% blended, nominal, after-tax), and accept an asymmetric distribution of risks. The asymmetric distribution requires that the project sponsor takes all of the risk of cost overruns and either shares or gives up the benefits of lower than anticipated costs (MDPU 2010, RI PUC 2010a).

Analysis of these PPAs suggests that some exposure to cost uncertainty is being managed through the inclusion of contingencies in the quoted capital cost of the projects. These contingencies, which are typically sized based on an independent advisor's assessment of the cost to resolve worst case scenarios, minimizes the probability that potential cost overruns will significantly affect cash-flows (Guillet 2007). Conceivably, this mitigation strategy allows the developer to accept "normal" rates of return around 10.5% nominal, after-tax (MDPU 2010, RIPUC 2010b). If exposure to construction risk was not mitigated, sponsors would likely require somewhat higher rates of return, and preliminary estimates suggest in the range of 12% to 15%.

Financing structures for offshore wind projects in the United States are also uncertain. In contrast to Europe, the majority of offshore wind project sponsors in the United States are independent power producers (IPPs) rather than utility subsidiaries. These IPPs probably do not have the capacity to finance the $1 to $3 billion capital cost of a project on their balance sheets. This limitation suggests that sponsors will probably have to tap equity and debt markets to finance the initial projects in the United States.

The terms of debt that the offshore wind project sponsors will obtain are highly uncertain. Experience in Europe suggests that sponsors could access debt at a cost of ~150 to 300 bps, with a debt to equity ratio of between 50% and 80%, and a term of the same length as the project's PPAs (see Section 3.5.1). However, the risk proposition for offshore wind projects in the United States is much different in terms of the availability and value of incentives, the degree to which PFIs can assume risk from private sector investors, and the certainty of the regulatory environment.

The probable financial structure and terms are so uncertain that a representative structure is not chosen for the baseline project. Instead, the baseline cost of capital is discussed in terms of a blended, after-tax discount rate (weighted-average cost of capital).

3.4.5 Discount Rate (d)

Data on likely financing rates for offshore wind projects are very limited. The blended discount rate of ~10.5% proposed by Cape Wind and Deepwater Wind seems to be reasonably representative of financing costs for similar projects with similar risk mitigation elements (e.g., fixed price PPAs and capital cost contingencies). However, the financing terms of a given offshore wind project will reflect the individual risk profile of that project as well as other market factors. A broad range of discount rates, from 8% to 15%, is defined to reflect the wide array of potential financing scenarios. Figure 31shows the range of nominal discount rates and NREL's baseline assumption.

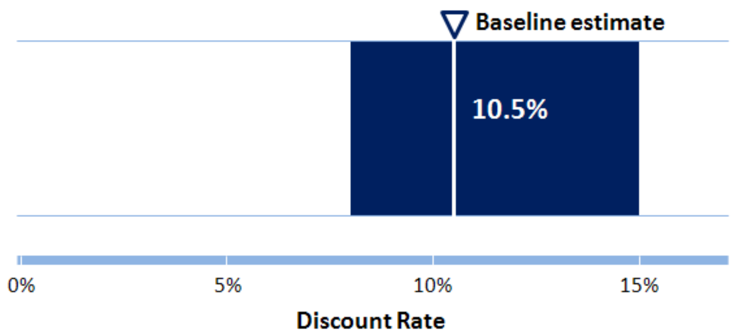

Figure 31. Range of discount rates and NREL baseline

As discussed above, the baseline discount rate estimate of 10.5% is not based on a single financial structure but as a weighted-average cost of capital. Assuming a 2.2% rate of inflation in 2010, the real, after-tax discount rate is estimated at 8.1% (Table 23).

Table 23. 2010 Offshore Wind Discount Rates (WACC)

Nominal Discount Rate (After-Tax)	Real Discount Rate (After-Tax)
10.5%	8.1%

3.4.6 Economic Evaluation Metrics (FCR and UCRF)

This section presents two metrics, the uniform capital recovery factor (UCRF) and the fixed charge rate (FCR), used in the economic evaluation of offshore wind energy investments. For detailed descriptions of these metrics see Section 2.5. Table 24 presents the estimated FCR and UCRF for the baseline project in nominal and real terms using the after-tax weighted average cost of capital (WACC) of 10.5% and 8.1%, respectively, a lifetime of 20 years, and a present value of depreciation factor of 77.8%.[34]

Table 24. 2010 FCR and UCRF Economic Evaluation Metrics

Fixed Charge Rate		Uniform Capital Recovery Factor	
Nominal	Real	Nominal	Real
14.0%	11.8%	12.1%	10.3%

The nominal FCR is estimated at 14.0%, and the real FCR is estimated at 11.8%. The nominal and real UCRF are estimated 12.1% and 10.3%, respectively. As noted in Short et al. 1995, comparisons of two or more capital investments should be on a consistent tax treatment basis (e.g., both investments use either a before-tax method or an after-tax method). NREL's methodology for the calculation of LCOE uses the real discount rate of 8.1% and the corresponding real FCR of 11.8%.

3.4.7 Project Life (n)

The first offshore wind turbines were installed at the 5-MW Videby Project in Denmark in 1991. In 2011, 20 years later, the project is still generating power (Blakewell 2011). The oldest utility-

[34] See Table A-2 in Appendix A for calculation of the present value of depreciation factor.

scale project, Horns Rev I, was commissioned in 2002 and has operated for only nine years. Because no project operators have decommissioned a project, the actual effective operating lives of offshore wind projects have not yet been validated by experience.

The lack of reliable data about the operating life of projects gives some uncertainty to the assumptions that can be used in cost-of-energy calculations. The majority of developers of both land-based and offshore wind projects currently assume a 20-year life in the development of their business cases. This is largely because the majority of commercially available offshore wind turbines are designed to operate for 20 years (Wiser et al. 2011). This might prove to be a low estimate as developers and financiers want to ensure that projects will be financially viable under conservative assumptions.

Some manufacturers are beginning to offer turbines that have longer structural design lives; Vestas announced a 25-year operational life for its new V-164 7.0-MW turbine (Vestas 2011). Bluewater wind, a U.S. offshore wind developer, signed a 25-year PPA with Delmarva (Delmarva 2008). The willingness of Bluewater to enter into a contract based on an assumed 25-year life suggests that longer design lives are a very real possibility for offshore wind projects. Some analysts expect this trend to continue and are even beginning to assume a 30-year project life for offshore wind projects.

The baseline project assumes a 20-year project life. Although NREL recognizes that this estimate is conservative, it seems to most accurately reflect the current assumptions used by developers and financiers in creating justifiable business cases for projects. Recognizing the evolving assumptions about project life, the range for operating life is assumed to extend from 20 to 30 years. Figure 32 shows the range of possibilities for the operational life of offshore wind projects in the United States and NREL's baseline assumption.

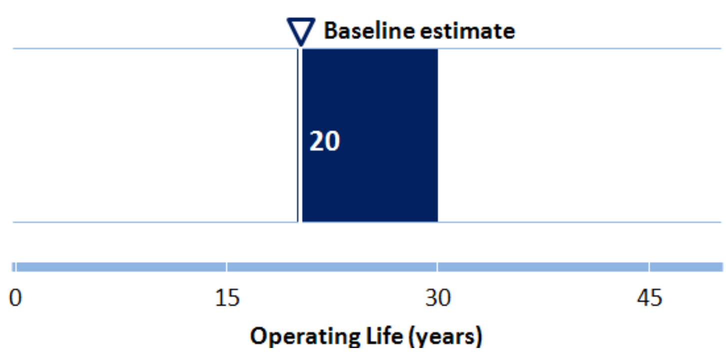

Figure 32. Operating life ranges and NREL baseline

Project life can affect the cost of delivered power by changing the period over which investment costs can be amortized. If a project is able to operate longer, holding all other variables constant, then the cost of energy will be lower. This can be observed in the FCR or the UCRF used to represent the financing cost for the project. Table 25 shows how the real and nominal FCR and UCRF vary from the baseline by assuming a 25- and 30-year operational life.

Table 25. FCR and UCRF Sensitivity to Project Lifetime

25-year Operational Life				30-year Operational Life			
FCR		CRF		FCR		CRF	
Nominal	Real	Nominal	Real	Nominal	Real	Nominal	Real
13.2%	10.9%	11.4%	9.5%	12.7%	10.3%	11.1%	9.0%

The table shows that the effective cost of capital, as measured by FCRs or UCRFs, decline as projects operate over longer periods.

3.5 LCOE Summary

3.5.1 Description of Baseline Project

The databases and analysis described above have informed the creation of the 2010 NREL Baseline project shown in Table 26. The NREL baseline project consists of 139 turbines on monopile foundations. The project site is 20 km from shore with an average water depth of 15 m. The turbines are rated at 3.6 MW with a 107-m rotor diameter and a 90-m hub height.

Table 26. Offshore Wind Project Assumptions Summary

General Assumptions	
Project capacity (MW)	**500**
Number of turbines	**139**
Turbine capacity (MW)	**3.6**
Site	
Depth (m)	**15**
Distance from shore (km)	**20**
Wind speed (m/s at a 50-m elevation)	**8.4**
Wind speed (m/s at a 90-m elevation)	**8.9**
Net capacity factor	**39%**
Technology	
Rotor diameter (m)	**107**
Tower height (m)	**90**
Gearbox	**3-stage**
Generator	**Asynchronous**
Foundation	**Monopile**
Cost	
Capital Cost (millions)	**$2,800**
Contingency (millions)	**$236**
AOE ($/MWh)	**$31**
Discount Rate (nominal)	**10.5%**
Discount Rate (real)	**8.1%**
Operating Life (years)	**20**
Fixed Charge Rate (real)	**11.8%**

The turbine uses a three-stage planetary/helical gearbox and an asynchronous generator. Average wind speed at the project site is 8.4 m/s at a 50-m elevation and 8.9 m/s at the 90-m hub height (class-6 wind regime).[35] The turbines are spaced 8 rotor diameters apart and are connected to the substation using a simple radial collection system design. The installed capital cost of the project is assumed to be $2.8 billon or about $5,600/kW, including a contingency estimated at 10% of hard capital costs. Annual operating expenses are equivalent to $31/MWh or $385,000 per turbine per year.

The weighted-average cost of capital (WACC), or discount rate, used to finance the project is estimated to be 10.5% nominal, after tax, which is equivalent to 8.1% real, after tax. Although this discount rate could represent a number of different financial structures, these are not examined in this analysis. The baseline project is assumed to have an operating life of 20 years from the date of commissioning. The fixed charge rate under these assumptions is 11.8%.

3.5.2 LCOE Calculation

Table 27 summarizes the offshore wind technology baseline project by detailed component cost categories and the LCOE calculation results. Major assumptions are defined in Table 27 and a comprehensive summary of assumptions can be found in Appendix B-2. Offshore wind component cost estimates draw from NREL's Cost and Scaling Model (Fingersh et al. 2006, Maples et al. 2010), several recent publications (Douglas-Westwood 2010, BVG 2011, Deloitte 2011), and NREL's conversations with offshore wind project developers in the United States. Estimates of the percentage contribution of individual project components to total capital costs were developed for each component. These estimates were applied to the total capital cost estimate developed in Section 3.2 to generate individual component costs. NREL plans to continue to collect market data and develop a bottom-up model to reflect current market data and improve understanding about scaling relationships in 2012.

[35] Average wind speed based on a Weibull probability distribution.

Table 27. Offshore Wind LCOE and Project Baseline Cost Breakdown

	3.6-MW Offshore $/kW	***3.6-MW Offshore*** $/MWh
TURBINE CAPITAL COST	**1,789**	**62**
Development (permits, engineering, site assessment, etc.)	58	2
Project management	117	4
Support structure	1,021	35
Port and staging	73	3
Electrical infrastructure	540	19
Transportation and Installation	1,109	38
BALANCE OF STATION	**2,918**	**101**
Insurance	94	3
Surety bond (decommissioning)	165	6
Contingency	471	16
SOFT COSTS	**730**	**25**
OVERNIGHT CAPITAL COST (OCC)	**5,437**	**188**
Construction financing cost	163	6
INSTALLED CAPITAL COST (ICC)	**5,600**	**194**
Levelized replacement cost ($/kW/yr)	40	12
Labor, equipment, facilities (O&M) ($/kW/yr)	46	13
OCS lease cost ($/kW/yr)	21	6
AFTER-TAX ANNUAL OPERATING EXPENDITURES (AOE)	**107**	**31**
NET ANNUAL ENERGY PRODUCTION (AEP) (MWh/MW/yr)	3406	
CAPACITY FACTOR (CF)	39%	
FIXED CHARGE RATE (FCR) (real, after-tax)	11.8%	
LELVELIZED COST OF ENERGY ($/MWh)	**225**	

The 2011 NREL baseline offshore wind project has an LCOE of $225/MWh. Figure 33 shows the life-cycle cost breakdown for the 2011 baseline offshore wind project.

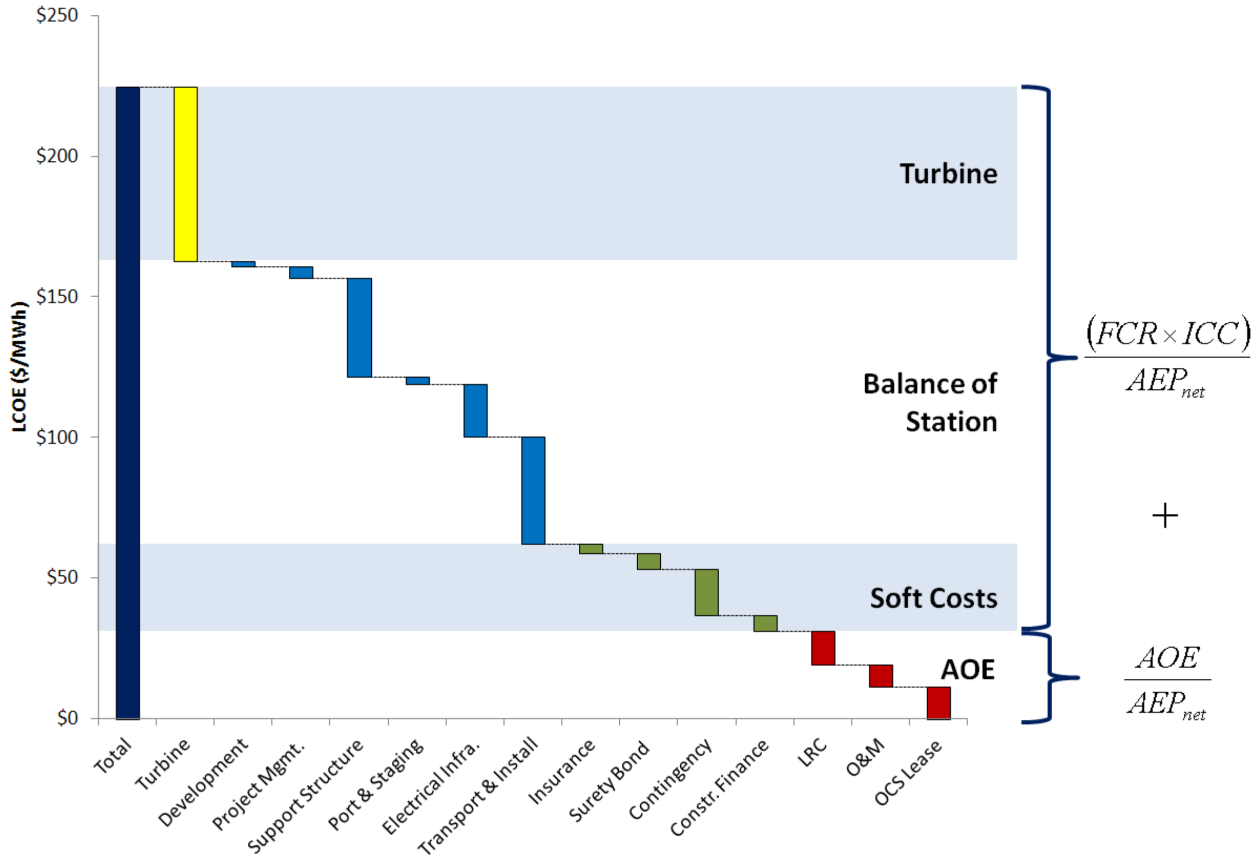

Figure 33. Cost breakdown for 2010 offshore wind reference project

3.6 LCOE Sensitivities

Although the input parameters used in the LCOE calculation represent the "best guess" at costs and operational parameters for a near-term offshore wind project, these inputs are subject to considerable uncertainty. Sensitivities of LCOE to five variables: 1) ICC, 2) AOE, 3) capacity factor, 4) discount rate, and 5) operational life, are tested using the observed ranges described in Sections 3.2 to 3.6, holding all other variables constant.

Figure 34 shows the baseline LCOE of $225/MWh as well as its sensitivity to changes in each of the five variables. The baseline estimate for each parameter, as well as high and low values, are shown as white text within each bar.

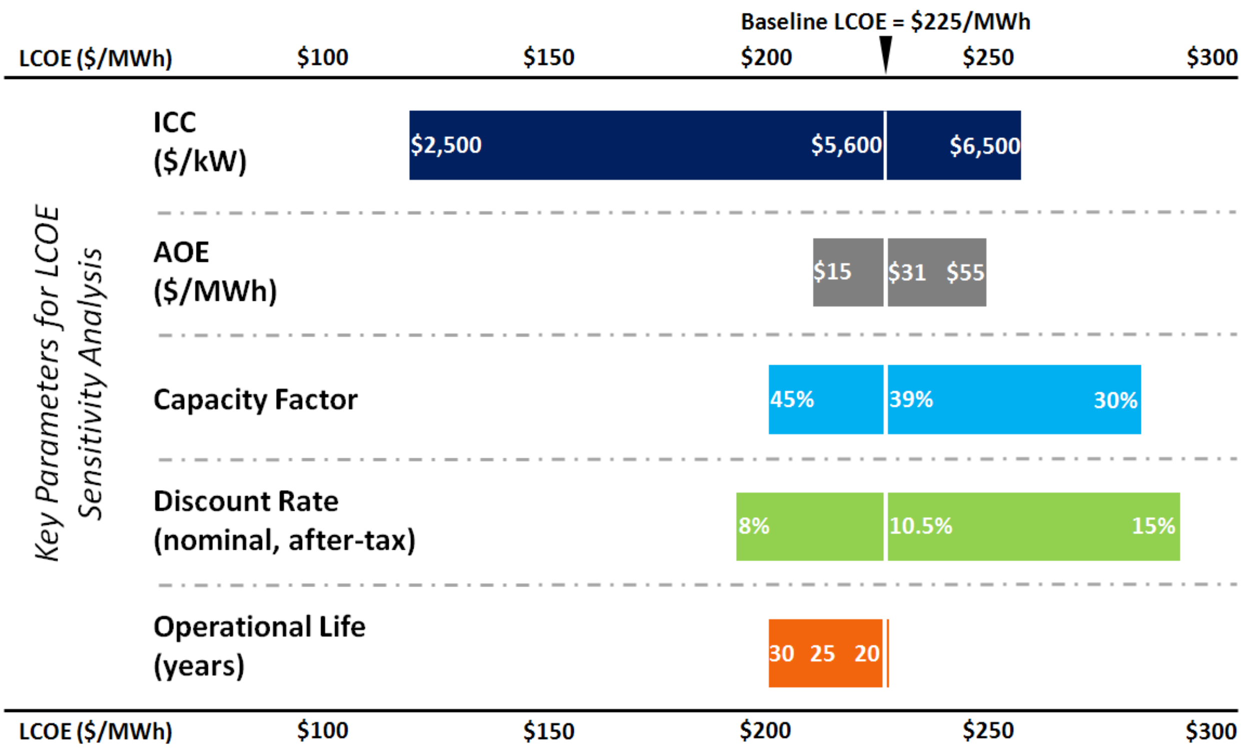

Figure 34. Sensitivity of offshore wind LCOE to key input parameters

Sensitivity ranges were selected to represent the highs and lows seen in industry. This selection of ranges provides insight into how real world ranges influence LCOE. The figure shows a very wide range of LCOE outcomes, extending from $118 to $292/MWh. Especially notable is the considerable impact on LCOE that could be achieved by reducing installed capital costs toward levels observed in the middle of the last decade (2000-2010). Coastal Point Energy (CPE), a firm that is developing projects in the Gulf of Mexico, believes that they can achieve costs near $2,500/kW with their initial deployment, scheduled for the 2012/2013 time frame (Breen 2011). If CPE is able to deliver the Galveston project within budget, this could herald a very different, much more competitive environment for offshore wind than outlined in this report.

The ranges in Figure 34 should not be taken as definitive. Changes in more than one of these variables could have an additive impact. Cost of energy is most sensitive to capital cost, operating costs, and discount rate, and appears to be least sensitive to operating life and operating costs.

3.7 LCOE Projections

The cost of delivered energy from offshore wind is generally expected to decline in the future. This section examines the cost reductions discussed in the literature that could result from incremental technology advancements, industry-based learning, and major technological innovations. It does not attempt to quantify the impact of market-based cost drivers (e.g., increased industry competition, supply and demand pressures, commodity price volatility, and changes in currency valuation); it also does not consider the potential for cost reductions resulting from activities to reduce the risk premium for offshore wind. With respect to the risk premium associated with first-of-a-kind U.S. projects, this analysis assumes that as capacity is installed in U.S. waters, the cost premium will diminish and LCOE will converge with the representative average.

With limited exceptions (e.g., UKERC 2010), cost reductions are not typically derived from changes in indirect costs associated with regulatory, siting or public acceptance barriers to projects.

Table 28 highlights typical technology and learning drivers expected to result in the LCOE reductions noted here. Quantification of the potential impacts that could be realized from each of these R&D/learning areas would require a detailed analysis, similar to the Wind Partnerships for Advanced Component Technology (WindPACT) studies conducted between 2000 and 2004 (Shafer 2001).

Table 28. Frequently Cited Drivers of Cost Reductions from R&D and Industry Learning

R&D/Learning Area	**Potential Changes** (For additional detail on technology changes and expected impacts, see references below)	**Expected Impact**
Turbine Scaling	Larger rotors, taller towers, higher nameplate capacity, primarily enabled by advanced controls (UpWind 2011). Manufacturing efficiency and quality assurance improvements (UKERC 2010, DOE 2008).	Component and machine economies of scale. Fewer trips from port to installation site. Fewer foundations and maintenance trips per unit of installed capacity. Downward pressure on production, installation and O&M costs.
Offshore Specific Turbine Designs	Explicit design for marine installations (i.e., port based assembly and industry specific installation vessels) and operating conditions (UKERC 2010, DOE 2008).	Minimize work at sea while increasing ease of maintenance and accessibility from offshore vessels. Maximize the value of simplified sea transport.
Foundation and Support Structures	Incremental modifications to existing technology. Development and maturation of technology for deepwater installations (Junginger et al 2004, UKERC 2010).	Minimize foundation costs through mass production, increased standardization and design refinement. Reduce time to install foundation infrastructure.
Installation Techniques and Vessels	Mission specific installation vessels (UKERC 2008) and enhanced installation techniques (Junginger et al 2004).	Increased installation efficiency, reduced weather risk, lower installation costs.
Grid Interconnection Infrastructure	Serial production of HV cable, improved DC conversion technology (Junginger et al 2004). Enhanced frequency and voltage control, fault ride-through capacity, broader operative ranges (UpWind 2011).	Reduced cost for grid interconnection, improved wind farm power quality and grid service capacity.
O&M Strategy	Enhanced condition-monitoring technology and design-specific improvements. Improved operations strategies (Wiggelinkhuizen et al. 2008).	Real-time, condition monitoring of turbine operating characteristics. Increased availability and more efficient O&M maintenance planning.

R&D/Learning Area	Potential Changes (For additional detail on technology changes and expected impacts, see references below)	Expected Impact
Resource Assessment	Turbine mounted real-time assessment technology (e.g., LIDAR) linked to advanced controls systems. Enhanced array impacts modeling and turbine siting capacity (UpWind 2011).	Increased energy capture while reducing fatigue loads, allows for slimmer design margins and reduced component masses; increased plant performance

Although the technology improvements highlighted in Table 28 are discussed throughout the literature, the vast majority of studies focusing on future offshore wind energy costs apply learning rates to project capital costs to estimate future cost reductions; a few (e.g., UKERC 2010, DOE 2008) also consider expert opinion when projecting future turbine costs. A limited number of studies envision capacity factor improvements over time, suggesting increased performance (e.g. UKERC 2010, DOE 2008). Wind turbines do not dominate offshore wind project costs to the same extent as their land-based counterparts. In some cases, turbines may represent only about 30% of offshore project costs as compared with approximately 70% of total project cost for land-based projects (Wiser and Bolinger 2010). Turbines still represent a significant share of installed capital cost, estimated at 32% in this study, and reducing the cost of turbines will be a crucial element of strategies to lower the future cost of offshore wind energy.

Turbine cost reductions are expected to result from continued scaling to higher capacity machines with larger rotors and taller towers. Dedicated offshore turbines along with increased equipment standardization and manufacturing efficiencies are also expected to drive down turbine capital costs.[36] A variety of advanced technology innovations have been suggested to offset theoretical weight increases associated with turbine upscaling. Advanced control systems and sensors, innovative materials with lower mass to strength ratios, and advanced blade designs, including structural design modifications and trailing edge flaps and flat-back airfoils, are expected to play a role in reducing blade and rotor mass (e.g., UpWind 2011, UKERC 2010, DOE 2008, Junginger et al 2004). The recently completed UpWind (2011) European Commission-sponsored research project also identified permanent-magnet transversal-flux generators from among 10 specific drivetrain configurations to be particularly promising in terms of drivetrain weight reduction. Advanced control systems and integrated system design are considered critical for reducing tower loading and allowing for the development and application of lower cost tower and support structure designs (UpWind 2011, DOE 2008). Future reductions in the cost of steel (in real terms) may allow for additional tower and drivetrain cost reductions (Junginger et al 2004).

At roughly 18% of installed project capital costs, foundations and support structures are also expected to be important variables in future offshore wind energy costs. In the short-term, there appears to be fewer consensuses about the future cost of offshore wind foundations. The uncertainty around near-term costs is largely a function of uncertainty around the cost of moving to deepwater foundations, including tripods and jackets. However, over the long-term, the impacts of technological learning, design standardization, and mass production are expected to

[36] Technology improvements including dedicated offshore designs and increased equipment standardization may also place downward pressure on O&M costs.

have a significant impact on tripod and jacket structures. Both Junginger et al (2004) and UKERC (2010) anticipate offshore foundation cost reductions on the order of 20% to 30%. Integrated analyses of turbines and their foundations coupled with better knowledge of soil and seabed conditions are also critical to the continued development of offshore foundations (Nielsen et al. 2009).

Logistics and installation costs provide another significant opportunity for reduction, accounting for more than 20% of installed capital costs. Junginger et al (2004) observed turbine installation learning rates on the order of 23% for the Horns Rev and Nysted offshore wind farms, which were completed in the early 2000s. Significant learning and efficiency improvements are expected to continue as dedicated vessels are designed and placed in service and general industry experience grows. Moreover, the development of port-based manufacturing facilities and quayside turbine assembly could reduce time and labor at sea further driving down installation and logistics costs.

Grid interconnection and electrical infrastructure costs are estimated at 10% of installed capital costs. The relative maturity of project collector equipment and technology suggests that intra-project collector systems are not likely to see significant cost reductions over time (Junginger et al 2004). However, maturation and serial production of high-voltage direct current (HVDC) cable and conversion technology are expected to drive down the costs of DC equipment, allowing projects located farther out to sea (i.e., greater than 50 km) to capitalize on the technical advantages (e.g., reduced losses, full control of reactive power, turbine operation with variable frequency) of DC equipment (Junginger et al 2004, UpWind 2011). Increased use of DC equipment could apply downward pressure to LCOE via lower project costs or increases in delivered energy.

In addition to reductions in project development and capital costs, reduced array losses, increased availability, and reduced O&M costs are fundamental to lowering future costs of delivered energy. Reduced losses are expected to require improved project and turbine siting and depend on continued resource assessment, analysis, and advanced array effects modeling capacity (UpWind 2011). Greater availability is expected from dedicated offshore equipment and improved O&M strategies. Remote condition monitoring coupled with greater awareness of failure indicators is expected to drive appropriate preventive maintenance and assist in identifying impending failures. Such approaches are anticipated to maximize the efficacy of time spent at individual turbines, which is a critical cost-saving measure for offshore installations with inherently limited access (Wiggelinkhuizen et al. 2008).

Figure 35 shows cost of energy projections from 25 different scenarios. Although the individual results vary, the overwhelming majority show costs declining between 2010 and 2030. By assuming cost reduction trends equivalent to those that are forecast in the literature, the figure illustrates where today's baseline costs fall relative to future projected costs.

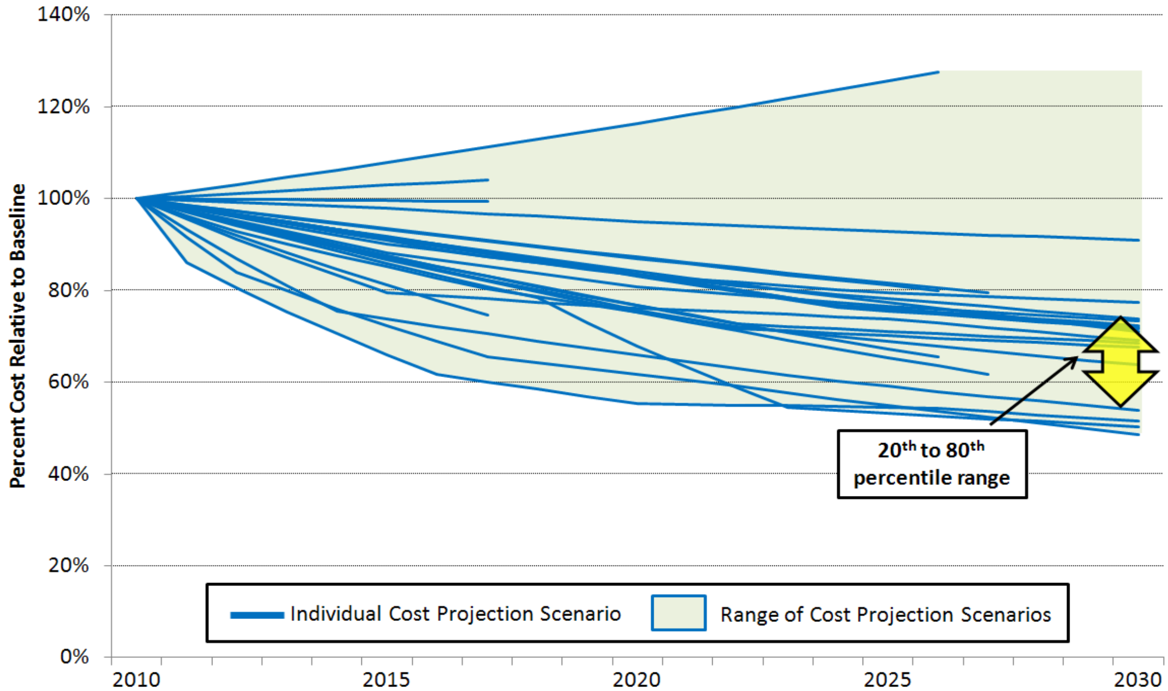

Figure 35. Multiple study results for projected offshore wind costs over time[37]

Note: Due to the relatively small sample size (16 independent estimates) the 20th to 80th percentile range is approximated by excluding the three high and three low estimates.

To arrive at the values shown in Figure 35, individual study or scenario data were extracted and normalized to common nominal values. From the normalized data, an estimated LCOE for each scenario was calculated. Where there were incomplete data for a given scenario (e.g., only capital costs available), representative industry data were utilized for other parameters necessary to calculate COE.[38] In some studies, multiple cost reduction scenarios resulted in the inclusion of multiple cost reduction trajectories. The starting point for each cost reduction trajectory was set to 2010. Although many of the studies reviewed were completed in years past, normalizing all studies to the same cost and time scale is justified because offshore wind deployment in the last decade has not been as robust as projected in the studies. This suggests that the majority of cost reduction opportunities reviewed in the literature have not yet been realized. This methodology allows focus on the magnitude of change rather than the absolute starting point. In total, this sample includes data from 12 different studies and 25 different scenarios.

[37] Data represents trends from 25 scenarios in 12 different studies. See Carbon Trust 2008, DOE 2008, European Commission 2007, EWEA 2009, GPI and EREC 2010, IEA 2009, Junginger et al. 2004, Krohn et al. 2009, Lemming et al. 2009, Musial 2010, Peter 2008, UKREC 2010. Trend data are normalized to 2010 and to the estimated cost for the Baseline project (Table 22).

[38] Trends in project capital costs were always reported, however, O&M and capacity factor were not reported in all studies.

After normalizing each study to 2010, the literature results project a very wide range of future offshore wind technology costs, reflecting the variety of assumptions made by each study about the development of offshore wind technology as well as future market conditions. However, the majority of these studies project reductions from the current baseline; projections within the 20th to 80th percentile predict that costs will decline by between 17% and 47% from today's levels through 2030.

The literature suggests that annual LCOE reductions from the 2010 baseline LCOE estimate could range from approximately 0% to 8% through the mid to latter part of this decade. At least one study scenario projects more dramatic reductions, nearly 14% per year through 2012. The rate of cost reduction is projected to fall to 0% to 3% per year starting in the early to mid 2020s and extending through 2030. Cost reductions are not projected to be greater than 2.5% in the late 2020s and continue to flatten through 2030.

As noted above, this analysis does not explore the potential impact of market-based cost drivers, including commodity price and labor cost variability, a change in turbine or industry supply and demand pressures, increased market competition (e.g., from low-cost Asian turbines), or changes in currency valuation. Any one of these factors could shift the cost reduction curve higher or lower. If the market conditions in the United States become more favorable to offshore wind, costs could be reduced without any technology improvements, innovations, or learning impacts.

3.8 Market Barriers for Offshore Wind

Barriers to the deployment of offshore wind projects in the United States are assessed in detail in NREL's *Assessing the Potential for Offshore Wind Deployment* report (Musial and Ram 2010). Many of the barriers to deployment will be addressed as the first offshore wind projects are completed and the costs, benefits, and impacts of projects are better understood by policy makers, developers, and the public. However, barriers related to the high cost of offshore wind energy are likely to persist until significant cost reduction occurs. Table 29 summarizes the major barriers that the offshore wind industry must confront.

Table 29. Major Barriers to Offshore Wind Deployment and Likely Impact

Barrier	Description	Likely Impacts
High Cost of Energy	Offshore wind is expensive compared to wholesale prices, especially true with prevailing low natural gas price environment	Initial projects built in response to state policy drivers (RPS carve-outs, REC multipliers, and legislated purchase mandates) limited utility demand for offshore wind power in absence of policy to support the industry
Revenue Uncertainty	RE incentives in the U.S. are generally technology agnostic and do not offer enough support to make offshore wind projects financially viable at prevailing wholesale rates Viability will require negotiation of above-market power prices between sponsors and utility, subject to approval by State PUC Limited market for offshore wind power makes early-stage development work highly speculative	Increased investment risk (price, volume risk) Limits amount of capital available to the industry, and increases required margins PPAs for offshore wind project likely to see legal challenges from consumer advocates

Barrier	Description	Likely Impacts
Regulatory Uncertainty	Offshore wind permitting process is highly fragmented, requires approval of 10+ federal agencies as well as local and state government agencies Permitting timeline is highly uncertain. Cape Wind is only project to receive full federal approval, a 10-year process DOI (BOEM) working with states and industry to improve and coordinate permitting process – "Smart from the Start"	Increased investment risk (regulatory risk) Project delays or cancelations Higher development costs
Availability of Financing	Offshore wind projects are capital intensive and initial projects carry high risks Utilities, the dominate funding source for European projects, generally not sponsoring U.S. offshore wind projects, which makes balance sheet financing scenarios unlikely No DOE Loan Guarantee Program to insulate private investors from construction risks	Limited availability of project finance capital Participation of European PFIs/ ECAs will probably be crucial
Supply Chain	U.S. supply chain for offshore wind is immature Turbine components likely sourced from Europe, at least for initial projects Ability of suppliers to deliver components and services within budget and schedule is unproven Jones Act constrains ability to transport goods between U.S. ports on foreign-built or foreign-owned vessels	Increased investment risk (construction risk, exchange-rate risk) ICC uncertainty
View shed Impacts	Some coastal residents and businesses concerned about impact of turbines on view sheds, property values, tourism Concerns could result in regulation and/or legal challenges	Delays or cancelations Public outreach efforts of developers will be important Could cause developers to build further from shore, increasing ICC
Environmental/ Wildlife Impacts	Offshore turbines present a potential threat to avian species, and could harm ocean-dwelling species European studies suggest that magnitude of impacts are limited, but no U.S., long-term data to confirm	Initial projects likely to require NEPA reviews, possibly long-term impact assessments Long lead time for deployments
Competing Uses	Many ocean stakeholders including DOD & USCG, commercial fishing, shipping, offshore O&G, recreational users, tribal nations	Stakeholder engagement efforts of developers will be important Delays or cancelations are possible

3.9 Conclusion and Future Work on Cost of Wind Energy

This report has presented a thorough picture of the levelized cost of land-based and offshore wind energy using real and modeled data representing market conditions in 2010. Scenario planning and modeling activities often focus on one number for land-based LCOE and one for offshore LCOE; in reality; however, the cost of land-based wind energy varies greatly across the United States and the cost of offshore wind LCOE varies greatly across Europe. Much uncertainty remains regarding domestic offshore wind deployment costs, as shown below in Table 30. This summary table presents representative ranges for 2010.

It is important to remember that the LCOE analysis presented in this report is only one way to measure the cost of wind energy, and that it does not include costs and issues vital to the wind project's viability such as grid interconnection, environmental, and military or other exclusion areas (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 production tax credits or investment tax credits that affect the sales price of electricity produced from wind projects.

Table 30. Ranges of LCOE and LCOE Elements for Land-Based and Offshore Wind in 2010

	Land-based	Offshore
Installed capital cost	$1,700–$3,000/kW	$2,500–$6,500/kW
Annual operating expenses	$4–$30/MWh	$15–$55/MWh
Capacity factor	25%–45%	30%–45%
Discount rate	6%–13%	8%–15%
Operational life	20–30 years	20–30 years
Range of LCOE	**<$60 – >$100/MWh**	**<$125 – >$290/MWh**

NREL has gained a solid understanding of costs associated with many components of land-based wind turbines and systems; however, future collaboration with industry would lead to better data and increased awareness of how much wind power system components cost and how costs may come down in the future. For offshore wind, NREL has provided a best estimate for potential domestic wind power projects with the assumptions in this report. Most research shows that the LCOE for both land-based and offshore wind is predicted to decline.

NREL intends to update this review of wind energy costs on an annual basis. This will help maintain a market perspective, as well as better understand the costs and performance of individual components to the wind generation system. Over time, these reports will improve understanding of costs and their effects on LCOE. The data and tools developed will be used to help inform projections, goals, and improvement opportunities. As the industry changes, NREL will continue to provide representative current project data and LCOE estimates for scenario planning, modeling, and goal-setting.

Future work entails two primary objectives: 1) continue to enhance data representing market-based costs, performance, and technology trends to reflect actual wind industry experience; and 2) enhance fidelity of bottom-up cost and performance estimation for individual wind plant components.

In FY12 NREL continues to work with industry and national laboratory partners to obtain project-specific data and improve modeling capability. NREL's wind analysis efforts include the development of:

- A better understanding of current O&M costs, including major component replacement costs and estimating the impact of anticipated improvements to O&M

for both land-based and offshore wind projects (e.g., distance from shore, weather windows, vessel design) on LCOE.

- Models that better represent BOS or non-turbine project costs (e.g., foundations, electrical cabling, and installation) for a range of turbine and project sizes for both land-based and offshore wind technology.
- Increased knowledge about barriers to wind power deployment such as transmission, radar, wildlife issues and public acceptance. NREL will work with industry and others to quantify the costs of deployment barriers and explain the impact of barriers on developable land with the intent of working towards barrier reduction in the future.
- Reference project descriptions based on market data and model results for mid-size wind technology and floating offshore wind technology.
- A new bottom-up wind plant component model that captures design loads and their relationship between wind plant components.

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Appendix A. Present Value of Depreciation Calculations

Land-Based Wind

Table A-1. Present Value of Depreciation Calculation for Land-Based Wind Baseline (*d*=8%)

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.5	18.5
2	80	32.00%	32	27.4	46.0
3	48	19.20%	19.2	15.2	61.2
4	28.8	11.52%	11.52	8.5	69.7
5	17.28	11.52%	11.52	7.8	77.5
6	5.76	5.76%	5.76	3.6	81.1

Offshore Wind

Table A-2. Present Value of Depreciation Calculation for Offshore Wind Baseline (*d*=10.5%)

Year	Net Book Value	5-Year MACRS Depreciation Schedule	Depreciation	Present Value Depreciation	Accumulated Present Value Depreciation
1	100	20.00%	20	18.1	18.1
2	80	32.00%	32	26.2	44.3
3	48	19.20%	19.2	14.2	58.5
4	28.8	11.52%	11.52	7.7	66.3
5	17.28	11.52%	11.52	7.0	73.3
6	5.76	5.76%	5.76	3.2	76.4

Appendix B. Summary of Assumptions for 2010 Baseline Projects

Land-Based Wind Project Assumptions

Table B-1. Comprehensive List of Assumptions for Land-based Wind Baseline Cost of Energy Calculation

Assumption	Units	Value	Notes
Project Information			
Capacity	MW	300	Calculation
Number of turbines	#	200	Representative of commercial-scale projects
Turbine capacity	MW	1.5	Most common turbine size in the United States
Net capacity factor	%	38	Class-4 wind resource (7.25 m/s @ 50 m), assumed losses (17%)
Rotor diameter	m	82.5	Most common rotor size of GE-1.5
Tower height	m	80	Average U.S. hub height
Operational life	years	20	Standard business case assumption
Installed Capital Costs (ICC)			
ICC ($)	$	646.5	Calculation
ICC	$/kW	2,155	Average ICC of 2010 U.S. projects
Market Price Adjuster	$/kW	362	Calculated to bring ICC in line with market conditions
Hard Costs			Estimated based on the Wind Turbine Cost and Scaling Model (Fingersh et al., 2006; Maples et al., 2010), and NREL's conversations with developers of land-based wind projects in the United States
Turbine	$/kW	1,212	
Foundations	$/kW	57	
Turbine transportation	$/kW	40	
Roads and civil work	$/kW	85	
Turbine assembly and installation	$/kW	59	
Electrical infrastructure	$/kW	154	
Engineering and permits	$/kW	24	
Soft Costs			
Construction finance	$/kW	63	
Contingency	$/kW	100	
Annual Operating Expenses (AOE)			
AOE Costs	($/MWh)	10	Representative of published literature and NREL's conversations with U.S. land-based wind developers
AOE Costs	($/kW/yr)	34	
LRC	($/kW/yr)	11	
O&M	($/kW/yr)	15	
Land Lease	($/kW/yr)	5	
Financing Costs (discount rate, FCR)			
Inflation rate	%	2.2	Assumption in EIA's 2010 Annual Energy Outlook

Assumption	Units	Value	Notes
Discount rate (nominal)	%	8	2010 land-based WACC averages
Discount rate (real)	%	5.7	
FCR (nominal)	%	11.4	Calculation
FCR (real)	%	9.5	
CRF (nominal)	%	10.2	
CRF (real)	%	8.5	
Taxes (T)			
Effective	%	38.9	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	6	Representative state tax rate
Depreciation (PVDep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr MACRS		Standard for choice for renewable energy projects
PV depreciation	%	81.1	Calculation
LCOE	**$/MWh**	**71**	**Calculation**

Offshore Wind Project Assumptions

Table B-2. Comprehensive List of Assumptions for Offshore Wind Baseline Cost of Energy Calculation

Assumption	Units	Value	Notes
Project Information			
Capacity	MW	500	Representative of commercial-scale projects
Number of turbines	#	139	Calculation
Turbine capacity	MW	3.6	Representative of turbine size planned for Cape Wind
Depth	m	15	Representative of proposed U.S. projects
Distance from shore	km	20	Representative of proposed U.S. projects
Net capacity factor	%	39	Class-6 wind resource (8.4 m/s @ 50 m), assumed losses (18%)
Rotor diameter	m	107	Representative of turbine size planned for Cape Wind
Tower height	m	90	Representative of turbine size planned for Cape Wind
Operational life	years	20	Standard business case assumption
Installed Capital Costs (ICC)			
ICC ($)	$ millions	2,800	Calculation
ICC	$/kW	5,600	Announced U.S. projects (recent), conversations with developers
Hard Costs			Percentages estimated based on the Wind Turbine Cost and Scaling Model (Fingersh et
Turbine	$/kW	1,789	

Assumption	Units	Value	Notes
Development	$/kW	58	al., 2006; Maples et al., 2010), several recent publications (Douglas-Westwood 2010, BVG 2011, Deloitte, 2011), and NREL's conversations with developers of offshore wind projects in the United States Percentage estimates applied to ICC estimate to obtain dollar per kW values
Project management	$/kW	117	
Support structure	$/kW	1,021	
Port and staging	$/kW	73	
Electrical infrastructure	$/kW	540	
Transport and install	$/kW	1,109	
Soft Costs			
Insurance during construction	$/kW	94	
Decommissioning bond	$/kW	165	
Construction finance	$/kW	163	
Contingency	$/kW	471	
Annual Operating Expenses (AOE)			
AOE Costs	($/MWh)	31	Representative of published literature and NREL's conversations with U.S. offshore wind developers
AOE Costs	($/kW/yr)	107	
LRC	($/kW/yr)	40	Representative of published literature and NREL's conversations with U.S. offshore wind developers
O&M	($/kW/yr)	46	
OCS Lease	($/kW/yr)	21	Cape Wind OCS lease – 2% operational revenue in yrs. 1–15, 7% of operational revenue in yrs. 15–20.
Financing Costs (d, FCR)			
Inflation rate	%	2.2	Assumption in EIA's 2010 AEO
Discount rate (nominal)	%	10.5	Approx. weighted-average cost of capital (WACC) for Cape Wind and Block Island Wind Farm
Discount rate (real)	%	8.1	
FCR (nominal)	%	13.9	Calculation
FCR (real)	%	11.7	
CRF (nominal)	%	12.2	
CRF (real)	%	10.3	
Taxes (T)			
Effective	%	38.9	Calculation
Federal	%	35	Standard federal corporate tax rate
State	%	6	Representative state tax rate
Depreciation (PVDep)			
Depreciable basis	%	100	Simplified depreciation schedule
Depreciation schedule	5-yr MACRS		Standard choice for renewable energy projects
PV depreciation	%	77.8	Calculation
LCOE	**$/MWh**	**225**	**Calculation**

Appendix C. Component Cost Descriptions

Notice: Unless otherwise noted, all dimensions are in meters and all masses are in kilograms, and the outputs of all formulas will be in 2002 dollars. An escalation can then be applied using the producer price indexes (PPIs) or gross domestic product (GDP). All information in Appendix C is from NREL's *Wind Turbine Design Cost and Scaling Model* (Fingersh et al 2006).

Blades

The blade-mass relationships were developed using WindPACT scaling study designs (Griffin 2001, Malcolm and Hansen 2006). The WindPACT static load design was also used by TPI Composites in their blade cost-scaling study (Henderson et al 2001). The static load design used International Electrotechnical Commission (IEC) Class-1 wind conditions, and the WindPACT baseline designs used IEC Class-2 wind conditions. Industry data compare well with the WindPACT baseline mass scaling relationship. It appears that typical, 2002 technology blades follow the WindPACT baseline design. In 2002, LM Glasfiber developed a new line of blades that take advantage of a lower weight root design. Carbon is included in the 61.5-m blade, but is not included in the other two lower weight blades. TPI performed an innovative blade design study that used several technology improvements to reduce blade weight. These designs were based on an IEC Class-3 wind condition, and the resulting weight is slightly lower than the commercially available LM blade of comparable length. The TPI study produced two blade designs using flat-back airfoils: one was all fiberglass and the other included a carbon fiber spar.

The study also developed two root designs: one used 120 studs and the other used 60 T-bolts. The four permutations of blade shell and root design result in blades of similar mass and cost. The use of carbon has not been isolated from other blade improvements, such as root design and airfoil selection. At this time, only one "advanced" blade curve seems appropriate, and this curve represents combinations of technology enhancements that may or may not include carbon. However, at some blade length, these improvements must include carbon to provide the necessary stiffness to avoid extreme blade deflection. This length is not yet identified. Also, the advanced blade technology should not be used for rotors less than 100 m in diameter. The baseline blade-mass relationship was selected to follow the WindPACT baseline design curve; the advanced blade-mass relationship was selected to follow the LM Glasfiber design curve. The WindPACT final designs from the rotor study (Malcolm 2006) indicate that even greater mass reduction as a function of blade length is achievable. Figure C1 shows the results of each of these studies.

Baseline: $\text{mass} = 0.1452 * R^{2.9158}$ per blade

Advanced: $\text{mass} = 0.4948 * R^{2.53}$ per blade

Where:

R = rotor radius

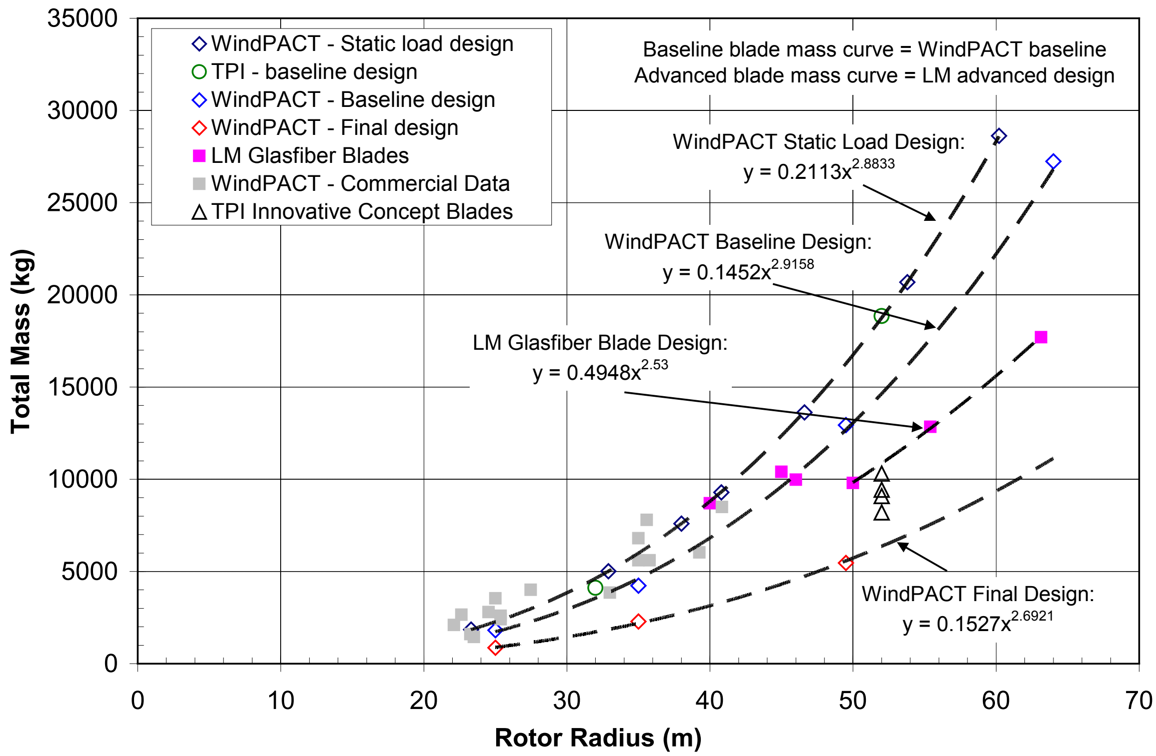

Figure C1. Blade-mass scaling relationship

The blade costs were developed using the TPI blade cost-scaling report (Henderson et al 2001). This study investigated the scaling effects of materials, labor, profit and overhead, and other costs such as tooling and transportation. Because the cost model does not include transportation of the blades in the turbine capital cost, the transportation portion of blade cost estimated by TPI was excluded. It was assumed that the profit, overhead, and other costs were a percentage of the material and labor costs. On average, this amounted to 28% for all blade lengths studied. The blade cost was then computed as the sum of the material costs and labor costs divided by 1–0.28, so that the other costs were maintained at 28% of the total blade cost. It was assumed that the labor costs would scale the same for the baseline blade and for the advanced blade. Two cost curves were created for the blade materials, representing the baseline design and the advanced design. A linear relationship between cost and R^3 was developed for the blade material cost to minimize deviation in the total blade cost curve fit. It was assumed that the advanced blade cost would scale with the baseline cost.

Although the mass curves scale differently between the baseline and advanced blades, this simplifying assumption was made because the baseline cost did not scale exactly the same as the mass. The cost estimate for the advanced blade consists of the average of the four cost estimates for the four different blade designs from the TPI innovative study. Because we lacked cost data for the advanced blade designs, the scaling was assumed to follow the baseline blade material cost. Note that the advanced blade cost is not in any way related to the advanced blade mass based on LM Glasfiber designs. These cost-scaling relationships are shown in Figure C2 with the WindPACT rotor study cost for comparison.

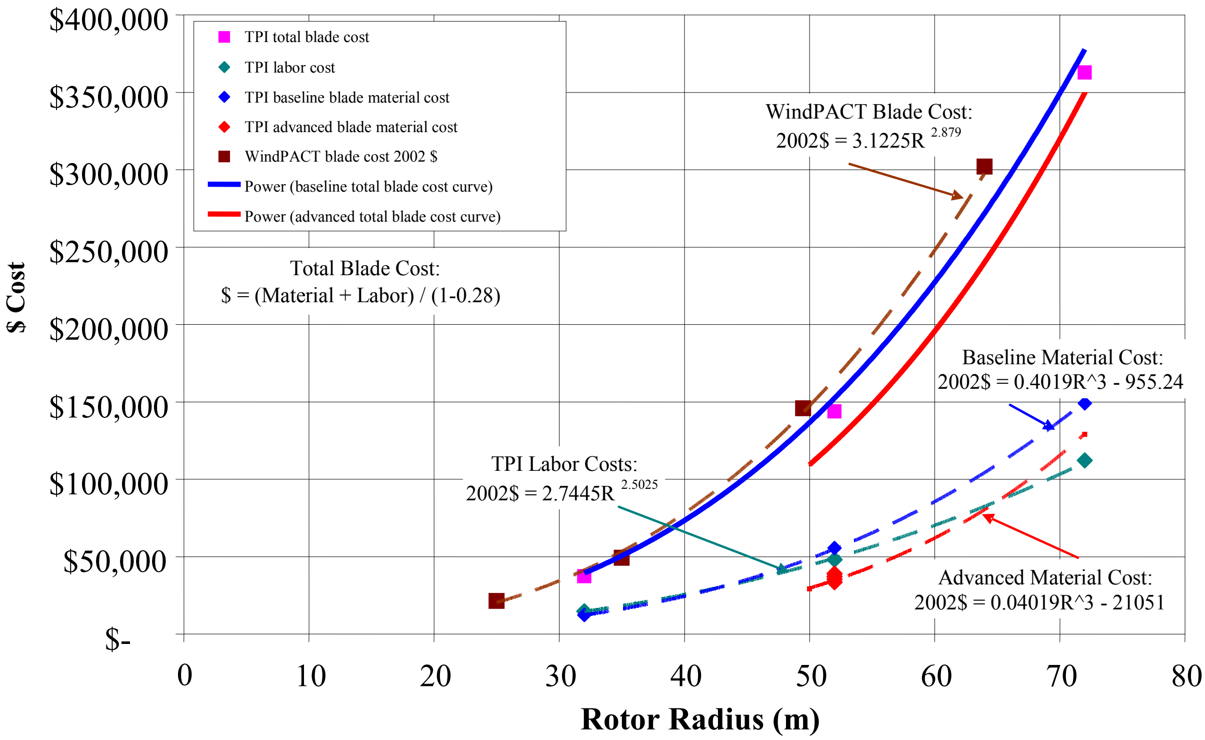

Figure C2. Blade cost-scaling relationship (per blade).

Cost = (material cost + labor cost)/(1 - 0.28)

Baseline cost = [(0.4019 * R^3 – 955.24) * BCE + 2.7445 * $R^{2.5025}$GDPE]/(1 - 0.28) per blade

Advanced cost = [(0.4019 * R^3 – 21051) * BCE + 2.7445 * $R^{2.5025}$GDPE]/(1 - 0.28) per blade

Where:

R = rotor radius

BCE = blade material cost escalator

GDPE = labor cost escalator

In the TPI cost-scaling study (Offshore Wind Energy 2001), the blade material components were presented for the three blade lengths studied. The average composition was determined and grouped into fiberglass, resin and adhesive, core, and studs corresponding to North American Industry Classification System (NAICS) industry codes. The TPI innovative blade design study (Manwell 2002) used costs in 2003 dollars. The blade composition was also presented for the four advanced blade designs, but for the escalation methodology, only the two fiberglass blades were examined. Using the blade material composition and the four NAICS codes, the blade costs were de-escalated to 2002 dollars to determine the blade material cost-scaling relationship. The cost model output, which allows the user to specify the output dollar year, is computed using the formula above. The blade material cost is escalated based on the four primary components: 1) fiberglass, 2) resin and adhesive, 3) core, and 4) studs. The baseline blade is assumed to be composed of 60% fiberglass, 23% vinyl adhesive, 8% studs, and 9% core material. The advanced blade is composed of 61% fiberglass, 27% vinyl adhesive, 3% studs, and 9% core material. In the preceding equations, the labor cost is escalated with the GDP, and the blade material cost is escalated with the composite escalator depending on the technology.

Hub

Development of a scaling formula for hubs began with the WindPACT rotor design study (Malcolm 2006). These data were further augmented by data from industry websites and low-wind-speed technology (LWST) project reports. A revised scaling curve was developed using hub mass as a function of a single blade mass. The revised formula is:

Hub mass = 0.954 * (blade mass/single blade) + 5680.3

Hub cost = hub mass * 4.25 (Malcolm 2006)

Pitch Mechanisms and Bearings

The pitch mechanisms model began with the WindPACT rotor design study data and was augmented with other available industry data and data from LWST reports. The bearing mass was calculated as a function of the blade mass for all three blades. Actuators and drives were estimated as 32.8% of the bearing mass + 555 kg.

Total pitch bearing mass = .1295*total blade mass (three blades) +491.31

Total pitch system mass = (total pitch bearing mass * 1.328) + 555

Cost of the pitch bearings was estimated as a function of the rotor diameter. The pitch housing and actuator cost was estimated as 128% of the bearing cost.

Total pitch system cost (three blades) = 2.28 * (.2106*Rotor Diameter $^{2.6578}$)

Spinner, Nose Cone

The spinner (nose cone) was not calculated independently in the WindPACT rotor study, so a new formula was derived, primarily from data in WindPACT drivetrain and LWST reports and augmented with data from the advanced research turbine at NREL's National Wind Technology Center (NWTC).

Nose cone mass = 18.5 * rotor diameter – 520.5

Nose cone cost = nose cone mass * 5.57

Low -Speed Shaft

The formula used to establish the outer diameter of the low-speed shaft was based on formulas for stress and strain at the main bearing where the shaft has the highest loads adjusted from the University of Sunderland report (Harrison 1993). Correction factors used in the equations were adjusted from their original state by selecting values more typical of larger turbines to more accurately represent low-speed shafts of turbines in the multimegawatt class. The main shaft was assumed to be supported by a bearing at both ends and to consist of a solid cylinder with a small hollow center and flanged ends for a bolted connection to the hub and gearbox. Low-speed shafts for direct-drive turbines and turbines utilizing a single bearing solution were not addressed, and were therefore, assumed to be the same as that of a geared machine. The inner-to-outer-diameter ratio of the main shaft was fixed at 0.1, with the length of the shaft fixed at 0.03*rotor diameter. The bending moment of the shaft is assumed to be 12.2625*rotor mass*shaft length/5. The original formula did not account for the addition of large connection flanges at both ends of the shaft; therefore, in this model, a term to add mass for the flanges was introduced. It was assumed that the mass of the flanges was 0.25*mass of shaft without the flanges. A hollowness of 1 and safety factor of 3.25 were used in accordance with the original formulas.

The resulting expressions for the calculation of the low-speed shaft's mass are as follows:

$$OD = \sqrt[3]{\frac{32}{\pi} * Hollowness * SafetyFactor * \left(\left(\frac{RotorTorque}{SteelYieldStress} \right)^2 + \left(\frac{BendingMoment}{SteelEnduranceLimit} \right)^2 \right)^2}$$

$$M_s = 1.25 * \frac{\pi}{4} * (OD^2 - ID^2) * L_s * \rho_s$$

$$M_f = 0.25 * \ M_s$$

$$Total\ mass = M_s + M_f$$

Where:

Ms = Mass of the shaft

Mf = Mass of the flanges

OD = Outer diameter of the shaft

ID = Inner diameter of the shaft

Ls = Length of the shaft

Ps = Density of the steel

The cost of the low-speed shaft was developed from data in the WindPACT Rotor Study (Malcolm 2006).

Low-Speed Shaft cost = $0.0998*(\text{Rotor Diameter})^{2.8873}$

Main Bearings

The WindPACT main bearing mass and cost, as reported in Shafer et al 2001, was stated incorrectly. This was corrected and reissued in April of 2006. The formula as stated in the revised report was used for this calculation. It is a function of the rotor diameter.

Bearing mass = $(\text{rotor diameter} * 8/600 - 0.033) * 0.0092 * \text{rotor diameter}^{2.5}$

The bearing housing mass was assumed to be equal to the bearing mass.

Total bearing system cost = 2 * bearing mass * 17.6 [6]

Gearbox

Gearboxes and generators are perhaps the most complicated components for which to predict a mass and cost. There are a range of designs and a myriad of ways in which to configure them. This work assumes four basic designs; all studied in detail in the two WindPACT drivetrain studies. The four designs covered in this model include a three-stage planetary/helical gearbox with high-speed generator, a single-stage drive with medium-speed generator, a multipath drive with multiple generators, and a direct drive with no gearbox. The primary source for information for the three-stage planetary/helical is the WindPACT rotor study, with costs adjusted from additional information in the two WindPACT advanced drivetrain studies (Poore 2003, Bywaters 2004). Data for the remaining three design types come primarily from the drivetrain studies and are adjusted for data from industry and LWST reports, where available. The mass for gearboxes is scaled based on the low-speed shaft torque and thus adjusts for differences in rotor diameter, tip speed, and tip-speed ratio. The cost is a function of machine rating in kilowatts.

Three-Stage Planetary/Helical

Mass = $70.94 * \text{low-speed shaft torque}^{0.759}$

Total cost = $16.45 * \text{machine rating}^{1.249}$

Single-Stage Drive with Medium-Speed Generator

Mass = $88.29 * \text{low-speed shaft torque}^{0.774}$

Total cost = $74.1 * \text{machine rating}^{1.00}$

Multipath Drive with Multiple Generators

Mass = 139.69 * low-speed shaft torque $^{0.774}$

Total cost = 15.26 * machine rating $^{1.249}$

Direct Drive

The direct-drive approach has no gearbox.

Mechanical Brake, High-Speed Coupling, and Associated Components

Brake cost is estimated as a function of machine rating. This was developed from the WindPACT rotor study cost data and converted to a function based on machine rating. Mass is back calculated based on $10/kg (Bywaters 2004).

Brake/coupling cost = 1.9894 * machine rating - 0.1141

Brake/coupling mass = brake coupling cost / 10

Generator

There is a wide range of possible generator designs. For this model, these designs are limited to high-speed wound rotor designs used with high-speed gearboxes, permanent-magnet generators used with single-stage gearboxes, multigenerator gearboxes, and direct-drive generators. Data for these designs were extracted primarily from the WindPACT rotor study and the two WindPACT drivetrain studies. These data were cross-checked with other data when available, such as the controls advanced research turbine at the NWTC. Generator mass calculations for high-speed wound rotor, medium-speed permanent-magnet, and multigenerator designs were based on machine power rating in kilowatts. They were each assumed to follow the same power law curve. The direct-drive mass has two possible equations (described below) based on low-speed shaft torque. All cost data are a direct function of machine rating.

Three-Stage Drive with High-Speed Generator

Mass = 6.47 * machine rating $^{0.9223}$

Total cost = machine rating * 65

Single-Stage Drive with Medium-Speed, Permanent-Magnet Generator

Mass = 10.51 * machine rating $^{0.9223}$

Total cost = machine rating * 54.73

Multipath Drive with Permanent-Magnet Generator

Mass = 5.34 * machine rating $^{0.9223}$

Total cost = machine rating * 48.03

Direct-Drive with Permanent-Magnet Generator
The mass of the direct-drive generator was updated to adequately represent permanent-magnet direct-drive (PMDD) generators in the 3 MW to 10 MW size range with a standard internal rotor design. The model does not currently have the ability to represent innovative PMDD generator designs, such as “inverted generators” with internal stators. Industry point designs in the range of 1.5 MW to 7 MW were analyzed for size, mass, torque, and air gap shear stress to develop two scaling relations for a PMDD generator. The first scaling relation assumed that the generator would be constrained to no more than 4.3 m in diameter because of transportation underpass and bridge limits. The second relation was developed to eliminate the diameter constraint for applications where transportation restrictions are less of a constraint or for generators that might be assembled on site. For each relation, a set of points was calculated based on physical machine parameters and plotted from 1 MW to 11 MW. A smooth curve fit was then developed for a PMDD generator from each dataset to produce the following relations:

Constrained diameter mass = 37.7*rated torque (Torque in kNm)

Unconstrained diameter mass = 172.8*rated torque$^{0.8}$ (Torque in kNm)

The cost of the PMDD generator was developed as a ratio between the WindPACT direct-drive generator rated at 1.5 MW and the WindPACT geared drivetrain generators derived in the *WindPACT Alternative Drivetrain Study* (Bywaters 2004).

Total cost = machine rating * 219.33

Variable-Speed Electronics
All designs in this model are assumed to have a power converter capable of handling full power output. This allows both variable-speed operation as well as “low-voltage ride through” when properly programmed. All converters are calculated as a function of rated machine power. A number of alternative approaches to power converters are possible, but they require additional study and modeling before incorporation into this tool. Mass for this component is not calculated, though in some designs a portion or the entire converter could be in the nacelle impacting structural and dynamics design issues.

Total cost = machine rating * 79 (Poore 2003)

Yaw Drive and Bearing
Yaw bearing costs were calculated using the original formula developed in the WindPACT rotor study; these were based on quotes from Avon Bearing. These calculations were sized on rotor diameter. Total yaw system cost is twice the bearing cost. Mass data in the WindPACT study were based on calculated moments. These moments were calculated using a structural dynamics program such as Fatigue, Aerodynamics, Structures, and Turbulence (FAST) or Automated Dynamic Analysis of Mechanical Systems (ADAMS). However, because these moments are not available in the design and cost-scaling model, the yaw bearing mass was calculated as a function of rotor diameter taken from the data supplied in the WindPACT rotor study. The bearing housing was estimated as 60% of the bearing mass.

Total yaw system mass = 1.6 * (0.0009 * rotor diameter $^{3.314}$)

Total cost = 2 * (0.0339 * rotor diameter $^{2.964}$)

Mainframe

Three-Stage Drive with High-Speed Generator

Formulas from the University of Sunderland report (Harrison 1993) were used to calculate the mass of the three-stage geared mainframe. Correction factors used in the University of Sunderland formula were adjusted by selecting values more typical of larger turbines to more accurately represent machines in the multimegawatt class. The calculations for the mainframe mass were based on estimates of rotor thrust, torque, mass, and area. The masses for each factor, with a bedplate area of 0.5*(0.0825*Rotor Diameter)^2 and a bedplate weight factor of 2.86 for a modular design, were calculated as follows (Harrison 1993):

Mass from torque = bedplate weight factor*0.00368*rotor torque.

Mass from thrust = 0.00158*bedplate weight factor*max thrust*tower top diameter

Mass from rotor weight = 0.015*bedplate weight factor*rotor mass*tower top diameter

Mass from area = 100*bedplate weight factor*bedplate area

Total mass = Σ of all masses

Mainframe cost = 9.489 * rotor diameter $^{1.953}$

Single-Stage Drive with Medium-Speed, Permanent-Magnet Generator

Mainframe mass = 1.295 * rotor diameter $^{1.953}$

Mainframe cost = 303.96 * rotor diameter $^{1.067}$

Multipath Drive with Permanent-Magnet Generator

Mainframe mass = 1.721 * rotor diameter $^{1.953}$

Mainframe cost = 17.92 * rotor diameter $^{1.672}$

Direct-Drive with Permanent-Magnet Generator

Mainframe calculations for PMDD machines assume that direct-drive machines need a smaller mainframe that is more integrated into the direct-drive generator itself and therefore, the mainframe cost and mass for direct-drive machines is 55% of that for a three-stage geared machine (Bywaters 2004).

Mainframe mass = 0.55 * equivalent three-stage mainframe mass

Mainframe cost = 0.55 * equivalent three-stage mainframe cost

Platforms and Railings

Platform and railing mass = 0.125 * mainframe mass

Platform and railing cost = mass * 8.7

Electrical Connections

Electrical connections, including switchgear and any tower wiring, were taken from the WindPACT rotor study and are calculated as \$40/kW of machine rating. No adjustment was made to these data.

Electrical connection cost = machine rating * 40 (Malcolm 2006)

Hydraulic and Cooling Systems

Hydraulic and cooling system estimates were taken from LWST reports. Mass is a function of machine rating in kilowatts. Cost is a function of machine rating times cost per kilowatt.

Hydraulic, cooling system mass = 0.08 * machine rating

Hydraulic, cooling system cost = machine rating * 12

Nacelle Cover

Nacelle cover costs were derived from WindPACT rotor study data combined with WindPACT drivetrain study and LWST report data. A single function was derived for all drivetrain configurations, as data were too scarce to develop individual formulas for different drivetrain configurations. The calculations are a function of machine rating in kilowatts. Nacelle cover mass was derived from nacelle cover cost. The cost per kilogram for the nacelle cover was taken from the WindPACT rotor study.

Nacelle cost = 11.537 * machine rating + 3849.7

Nacelle mass = nacelle cost / 10 (Malcolm 2006)

Control, Safety System, Condition Monitoring

WindPACT studies identified a cost of \$10,000 for control, safety, and condition-monitoring systems for a 750-kW turbine. A slight scaling factor was applied for larger machines to account for additional wiring and sensors. However, these data were based on 1999 designs. During the early 2000s, operators realized the value of additional sensing and monitoring systems. To account for this, the number for land-based systems was increased to \$35,000 in 2002 dollars, regardless of machine size or rating.

Tower

The tower mass and cost-scaling relationships were based primarily on the WindPACT studies (Smith 2001, Malcolm 2006). All towers discussed here are steel tubular towers. The tower mass is scaled with the product of the swept area and hub height, as shown in Figure C3. Given any turbine diameter, hub height, and tower mass, a comparison can be made between steel tubular towers. The initial WindPACT scaling studies provide a crude estimate of tower mass based on the most extreme base moment. Turbines are designed for trade-offs between buckling and overturning moment for a more precise set of load conditions. Fatigue loads are also estimated.

The WindPACT rotor study baseline design (Malcolm 2006) uses conventional technology circa 2002 and scales it up. The WindPACT rotor study final design (Malcolm 2006) uses advanced technologies including, tower feedback in the control system, flap-twist coupling in the blade, and reduced blade solidity in conjunction with higher tip speeds. These final designs show the trends for future design.

Commercial turbines were compared with these WindPACT scaling relationships. This comparison assumes that the different rotors have similar thrust coefficients. The tower mass, provided by the manufacturers, is based on a design for the variety of design conditions and tradeoffs for turbines with different rotors and hub heights. The WindPACT rotor study baseline design scaling relationship represents most commercial turbines of 2006, but it may be somewhat conservative. The WindPACT rotor study final design scaling relationship may be achievable through technology innovation, but it results in mass projections much lower than what was commercially available in 2006. The impact of towers with base diameters of greater than 4.3 m is generally reflected in the transportation and erection costs, but these functions should be used carefully when looking at towers of much greater than 80 m, as design trade-off for transportation and erection will have a major impact on design.

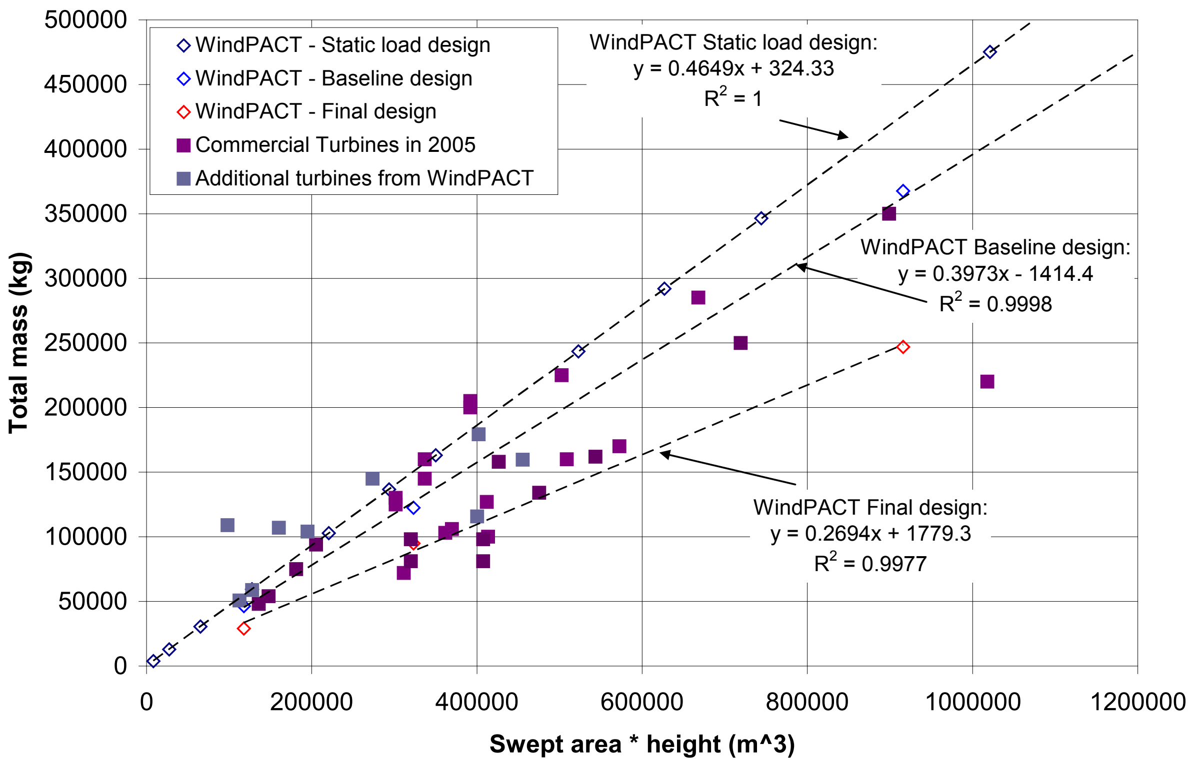

Figure C3. Tower mass scaling relationship

Baseline: mass = 0.3973 * swept area * hub height – 1414

Advanced: mass = 0.2694 * swept area * hub height + 1779

WindPACT cost of steel was \$1.50/kg in 2002 dollars. The tower cost is computed as follows:

Total cost = mass * 1.50

The cost is then escalated using the PPI to the appropriate year dollars.

Foundation

Foundation estimates are based solely on the WindPACT rotor study report. Foundations used to develop these estimates were primarily based on a design by Patrick and Henderson that can generally be described as a hollow drilled pier. These foundations are approximately the diameter of the tower base and may be 30 feet or more in depth. A number of alternate foundation designs are possible that will vary based on local soil conditions. No attempt has been made here to try to evaluate different design approaches. Foundations were scaled as a function of hub height times rotor swept area, which is directly proportional to the tower overturning moment. No mass data were calculated for the foundation.

$$\text{Foundation cost} = 303.24 * (\text{hub height} * \text{rotor swept area})^{0.4037}$$

Transportation

The transportation estimate was taken from the WindPACT logistics study (Smith 2001) and is a function of machine rating. These costs reflect the large cost increases required for 3-MW and 5-MW turbines if transported and erected onshore.

$$\text{Transportation cost factor (\$/kW)} = 1.581\text{E-}5 * \text{machine rating}^{2} - 0.0375 * \text{machine rating} + 54.7$$

Transportation cost = machine rating * cost factor above

Roads, Civil Work

Estimates for roads and civil work were taken directly from the WindPACT logistics study (Smith 2001). These estimates include modifications to road widths and crane pads to handle larger machines. Cost is a function of machine rating in kilowatts.

$$\text{Roads, civil work cost factor (\$/kW)} = 2.17\text{E-}6 * \text{machine rating}^{2} - 0.0145 * \text{machine rating} + 69.54$$

Roads, civil work cost = machine rating * cost factor above

Assembly and Installation

Data for this relationship were taken from the WindPACT rotor study, which developed a formula based on machine rating. This formula was not used. Instead, it was found that a relationship based on hub height times rotor diameter gave almost a straight line relationship. Though both of these relationships give a close-to-linear relationship, it is believed that a function that accounts for the physical size of the largest components will give a more direct relationship as these components change in size. This relationship was used in the model.

$$\text{Assembly and installation} = 1.965 * (\text{hub height} * \text{rotor diameter})^{1.1736}$$

Electrical Interface/Connections

Electrical interface covers the turbine transformer and the individual turbine's share of cables to the substation. These data originally came from the WindPACT balance-of-station study (Shafer 2001) and were used in this model as originally derived.

Electrical interface/connection cost factor ($/kW) = 3.49E-6 * machine rating ^{2} – 0.0221 * machine rating + 109.7

Electrical interface/connection cost = machine rating * electrical cost factor above

Engineering, Permits

Engineering and permits covers the cost of designing and permitting the entire wind facility, allocated on a turbine-by-turbine basis. These costs are highly dependent upon the location, environmental conditions, availability of electrical grid access, and local permitting requirements. The formulas provided here were first derived from the WindPACT balance-of-station cost study (Shafer 2001) and were used in this model without modification.

Engineering, permits cost factor ($/kW) = 9.94E-4 * machine rating + 20.31

Engineering, permits cost = machine rating * engineering, permits cost factor above

Land Lease Costs

Wind turbines normally pay lease fees for land used for wind farm development. This cost is principally based on the land used by the turbine. The factors applied in different wind farm developments vary widely depending on the wind class of the particular site, the nature and value of the land, and the potential market price for the wind. No single number or model is currently available to predict these costs based on turbine rating, size, or wind class. The number used in this model is based on a cost per kilowatt-hour of production making it highly variable with wind class and machine performance. This cost was proposed for the LWST Project and defined in the report on pathways analysis (Malcolm 2006). Although the use of a cost per kilowatt-hour appears inappropriate in the long run, this number is currently frozen at $0.00108/kWh until better information is available.

LLC cost = $0.00108/kWh * AEP