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WP2

IEA Wind Task 26

The Past and Future Cost of Wind Energy

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iea wind

NATIONAL RENEWABLE ENERGY LABORATORY

IEA Wind Task 26: The Past And Future Cost Of Wind Energy

Work Package 2

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Executive Summary

Over the past 30 years, wind power has become a mainstream source of electricity generation around the world. However, the future of wind power will depend a great deal on the ability of the industry to continue to achieve cost of energy reductions. This summary report, developed as part of the International Energy Agency (IEA) Wind Implementing Agreement Task 26, *The Cost of Wind Energy*, provides a review of historical costs, evaluates near-term market trends, reviews the methods used to estimate long-term cost trajectories, and summarizes the range of costs projected for onshore wind energy across an array of forward-looking studies and scenarios. It also highlights high-level market variables that have influenced wind energy costs in the past and are expected to do so into the future.

Historical and Near-Term Trends in the Levelized Cost of Wind Energy

Between 1980 and the early 2000s, significant reductions in capital cost and increases in performance had the combined effect of dramatically reducing the levelized cost of energy (LCOE) for onshore wind energy. Data from three different historical evaluations, including internal analysis by the Lawrence Berkley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) as well as published estimates from Lemming et al. (2009) and the Danish Energy Agency (DEA) (1999), illustrate that the LCOE of wind power declined by a factor of more than three, from more than \$150/MWh to approximately \$50/MWh between 1980s and the early 2000s (Figure ES-1). However, beginning in about 2003 and continuing through the latter half of the past decade, wind power capital costs increased—driven by rising commodity and raw materials prices, increased labor costs, improved manufacturer profitability, and turbine upscaling—thus pushing wind's LCOE upward in spite of continued performance improvements (Figure ES-1).

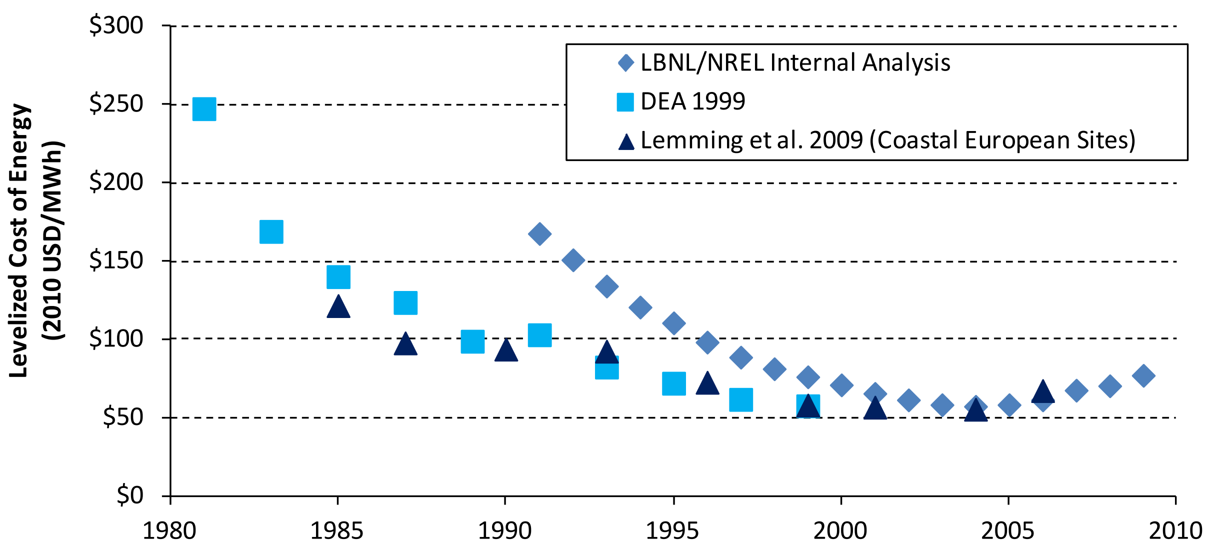

Figure ES-1. Estimated LCOE for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives)

Sources: LBNL/NREL (internal analysis), Lemming et al. 2009, and DEA 1999

More recently, turbine prices and therefore project capital costs have declined, but still have not returned to the historical lows observed earlier in the 2000s. At the same time, however, performance improvements have continued. As a result, modeling based on capital cost and performance data from the United States and Denmark for projects expected to be built in 2012–2013 suggests that the LCOE of onshore wind energy is now at an all-time low within fixed wind resource classes, and particularly in low and medium wind speed areas (Figure ES-2). Moreover, the fact that capital costs remain higher than in the early 2000s but that those increased costs are rewarded by improved performance and a lower LCOE demonstrates the fundamental interdependence of capital cost and performance in wind turbine and project design.

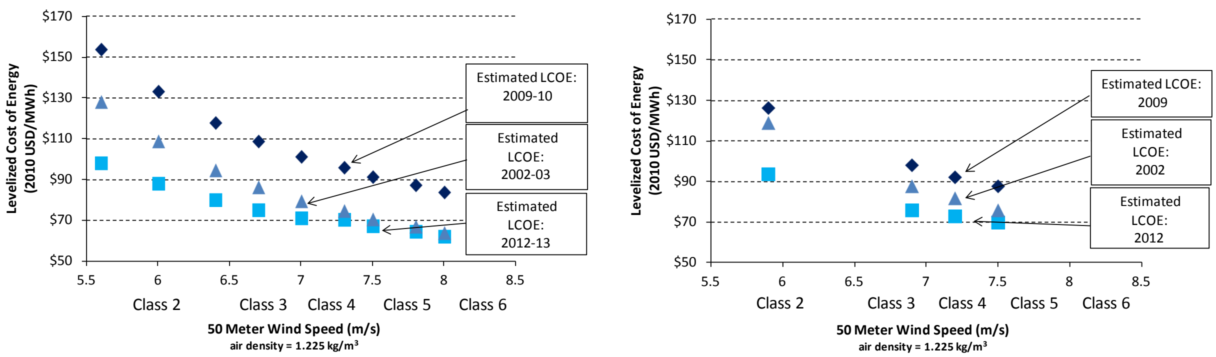

Figure ES-2. LCOE for wind energy over time in the United States (left) and Denmark (right)

Sources: Wiser et al. 2012, James-Smith 2011b

Long-term Trends in Wind Energy LCOE

Further into the future, the LCOE of wind energy is expected to continue to fall, at least on a global basis and within fixed wind resource classes. Performance improvements associated with continued turbine upscaling and design advancements are anticipated, and lower capital costs may also be achievable. The magnitude of future cost reductions, however, is highly uncertain. Estimates of the future cost of onshore wind energy conducted to date have often been the result of an iterative process that incorporates some combination of historical trends, learning curve analysis, expert elicitation, and engineering modeling. Figure ES-3 presents the estimated cost reductions anticipated by 13 recent analyses covering 18 cost scenarios. Many of these studies utilize learning curves in combination with expert elicitation, engineering models, and near-term market analysis (e.g., EWEA 2009, U.S. DOE 2008, GWEC/GPI 2010, and Lemming et al. 2009).

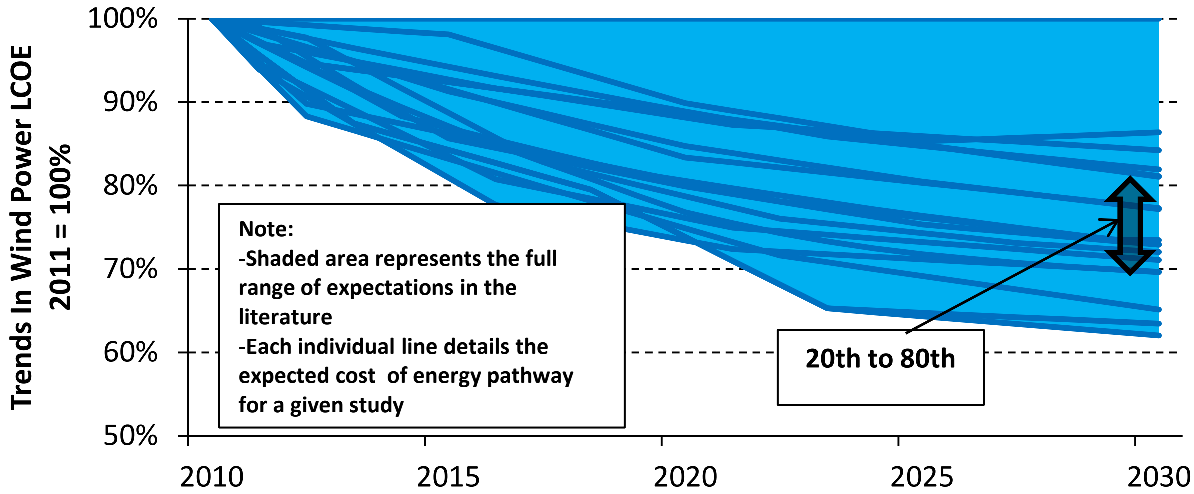

Figure ES-3. Estimated range of wind LCOE projections across 18 scenarios

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 2011, EPRI 2010, Peter and Lehmann 2008, GWEC/GPI 2010, IEA 2009, and European Commission 2007

The data presented in Figure ES-3 suggest an approximate 0%–40% reduction in LCOE through 2030. The single scenario anticipating no further cost reductions assumes that the upward price pressures observed between 2004 and 2009 are moderated but remain significant enough to prevent future reductions in LCOE. The three studies anticipating a 35%–40% reduction in LCOE by 2030 represent ambitious scenarios requiring concentrated efforts to reduce the cost wind energy, relatively high rates of global deployment, and levels of investment that exceed business as usual. By focusing on the results that fall between the 20th and 80th percentiles of scenarios, the range is narrowed to roughly a 20%–30% reduction in LCOE. Cost of energy reductions are generally expected to be greater in the early years and then slow over time. Initial cost reductions range from 1%–6% per year. By 2030, all but one scenario envisions cost reductions falling below 1% per year.

A large number of technological and market-based drivers are expected to determine whether these projections are ultimately realized. Possible technical drivers are summarized in Table ES-1 and include reduced component loads and increased reliability. At the same time, a resurgence in turbine demand, resulting in supply chain pressures similar to those observed between 2004 and 2009 could counter cost reductions resulting from continued technical advancements. Continued movement toward lower wind speed sites may also increase fleet-wide LCOE, despite technological improvements that would otherwise yield a lower LCOE. On the other hand, increasing competition among manufacturers and developers could drive down the LCOE of onshore wind energy to a greater extent than otherwise envisioned.

Table ES-1. Potential Sources of Future Wind Energy Cost Reductions

R&D/Learning Area	Potential Changes (For more detail on technology changes and expected impacts, see references below)	Expected Impact
Drivetrain Technology	Advanced drivetrain designs, reduced loads via improved controls, and condition monitoring (Bywaters et al. 2005)	Enhanced drivetrain reliability and reduced drivetrain costs
Manufacturing Efficiency	Higher production volumes, increased automation (Cohen et al. 2008), and onsite production facilities	Enhanced economies of scale, reduced logistics costs, and increased component consistency (allowing tighter design standards and reduced weights)
O&M Strategy	Enhanced condition monitoring technology and design-specific improvements and improved operations strategies (Wiggelinkhuizen et al. 2008)	Real-time condition monitoring of turbine operating characteristics, increased availability, and more efficient O&M planning
Power Electronics/Power Conversion	Enhanced frequency and voltage control, fault ride-through capacity, and broader operative ranges (UpWind 2011)	Improved wind farm power quality and grid service capacity, reduced power electronics costs, and improved turbine reliability
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, allowing for slimmer design margins and reduced component masses; increased plant performance
Rotor Concepts	Larger rotors with reduced turbine loads allowed by advanced controls (Malcolm and Hansen 2002) and application of light-weight advanced materials	Increased energy capture with higher reliability and less rotor mass; reduced costs in other turbine support structures
Tower Concepts	Taller towers facilitated by use of new design architectures and advanced materials (Cohen et al. 2008, LaNier 2005, Malcolm 2004)	Reduced costs to access stronger, less turbulent winds at higher above-ground levels

Conclusions and Future Work

Following a long period of historical declines, wind energy costs were increasing for much of the past decade. However, today, the cost of onshore wind energy once again appears to be falling and is expected to reach a historic low in the near future within fixed wind resource areas. Continued cost reductions are expected through 2030, but the anticipated magnitude of those reductions varies widely and will ultimately be determined by an array of technical and non-technical variables.

Recent capital cost and performance trends have underscored the need for a view of the cost of wind energy that equally weighs both trends in capital cost and performance, particularly when trying to understand the future cost of wind energy. The technology is now at a point where an optimal cost of onshore wind energy may result from little or no further capital cost reductions (and perhaps even modest capital cost increases), but continued performance improvements. In this environment, it is possible to see capital costs remain relatively flat—with possible modest reductions or increases, depending on local market conditions—into the future and to see performance increases as the primary target of original equipment manufacturers (OEMs).

Further improving our understanding of possible future cost trends will require additional data gathering and improved modeling capability. Robust data collection is needed across the array of variables that must be factored into estimating LCOE (e.g., capital cost, capacity factor, O&M costs, component replacement rates and costs, and financing costs) and in each of the wind energy markets around the globe. Also needed are data on the many contextual factors that impact the overall cost of wind energy and that may also vary with time, such as interconnection costs, permitting costs, and the average wind speed of installed wind projects. Such data would allow historical LCOE trends to be more closely analyzed, with insights gleaned both through more sophisticated learning curve analysis as well as bottom-up assessments of historical cost drivers. Additional data could also assist in better distinguishing those cost reductions that result from technological improvements from those changes in cost that result from external supply and demand market variables or changes in raw material and commodity prices. It is only with this improved historical understanding that future possible cost trajectories can be fully understood (Dinica 2011). An enhanced capacity to model the cost and performance impacts of new technological innovation opportunities, taking into account the full system dynamics that result from a given technological advancement, is also essential. Component, turbine, and project-level design and cost tools of this nature would allow for more sophisticated cost modeling and provide greater insights into possible future costs based on changes in material use and design architectures. Together these efforts would enhance our ability to understand future costs, facilitate prioritization of research and development (R&D) efforts, and help to understand the role and required magnitude of deployment incentives into the future.

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1 Introduction

Wind energy has been utilized by human society for millennia. The first experiments with wind-generated electricity, however, date to the late 19th century, and it was not until the 1970s that wind energy began to penetrate commercial power markets—first in Denmark, then in California in the 1980s, and in Germany and Spain in the 1990s (Wiser et al. 2011b). Since the mid-1990s, wind energy has evolved into a mainstream source of power generation, with more than 200 gigawatts (GW) installed around the world (GWEC 2011, BNEF 2011b). A substantial fraction of the newly installed total global electric generation capacity each year now comes from wind. Wind energy is estimated to deliver the equivalent of just over 2% of global electricity consumption (Wiser and Bolinger 2011), though that contribution varies considerably by region (GWEC 2011).

The emergence of wind energy as a major source of power around the world correlates with policy support for renewable energy technologies. Policy support has been driven by concerns around energy security, economic development, and environmental protection. Without policy support, much of the deployment occurring today would not be economically feasible (Wiser et al. 2011).[1] Deployment of wind power is also correlated with significant reductions in the cost of wind-generated electricity. Between 1980 and the early 2000s, wind power installation costs fell by more than 65% in the United States (Wiser and Bolinger 2011) and 55% in Denmark (Nielsen et al. 2010). As a result of these dramatic cost reductions, wind energy, in some parts of the world, has achieved costs that are competitive with prevailing market prices without policy support (Berry 2009, IEA 2009, and IEA and OECD 2010).

The future of wind energy will depend a great deal on the ability of the industry to continue to achieve cost reductions and, ultimately, to achieve cost parity with conventional sources of generation (i.e., to compete without direct policy support) across a broad array of contexts and locations. The importance of future cost competitiveness has been reinforced by the difficulty in developing international consensus around climate change policy (Pielke 2010). Moreover, with increasing pressure on governments to reduce spending and debt, long-term policy support for wind energy remains uncertain. Estimates by the Global Wind Energy Council (GWEC) and Green Peace International (GPI) (GWEC/GPI 2010) suggest that supplying 20% of global electricity demand with wind energy is possible; however, achieving such penetration would be greatly facilitated by significant future cost reductions.

At the highest level, this summary report provides a review of historical cost, evaluates near-term market trends, reviews the methods used to estimate long-term costs trajectories, and summarizes the range of costs projected for onshore wind energy across an array of forward-looking studies and scenarios. It also highlights high-level market variables that have influenced wind energy

[1] Arguably, the need for policy support of wind energy to drive deployment in much of the world is, in part, due to the tendency of electricity markets to inherently favor incumbent generation technologies. For example, grid systems were not historically designed to integrate variable generation resources, and much of the existing grid system was not designed to access geographically constrained renewable energy resources. Moreover, incumbent technologies have, in many cases, continued to benefit from direct and indirect policy support in the form of fuel production incentives, rail and pipeline development incentives, and socialization of risk (e.g., nuclear power). For these reasons—and because wind energy is believed to provide public benefits (e.g., environmental gains)—advocates argue that policy support for wind energy is often justified.

costs in the past and are expected to do so into the future. More specifically, Section 2 begins by summarizing historical capital costs and performance data in the United States and in various European countries (for which data were available). Section 3 considers these trends from the perspective of the cost of delivered energy and estimates the near-term cost of energy for projects in late-stage development in the United States and Denmark today. Section 4 provides an in-depth look at the strengths and weaknesses of the various methods used to estimate the future cost of wind energy over the long term, summarizes a sample of projections made by a variety of institutions under both conservative and optimistic assumptions, and discusses potential sources of future cost reductions.

This report has been developed as part of the International Energy Agency (IEA) Wind Implementing Agreement Task 26, *The Cost of Wind Energy*, and builds on the prior work of this task to estimate the 2008 cost of wind energy among the participating countries (Schwabe et al. 2011). As in the prior report, analysis estimating the levelized cost of energy (LCOE) for wind included here utilized the discounted cash-flow model developed by the Energy Research Centre of the Netherlands (Schwabe et al. 2011); however, data presented here also rely on LCOE estimates generated from other sources, as noted in the text. Additional input to this report comes from published data as well as data provided to the Task 26 Working Group by participating members. Specifically, Task 26 participant presentations, which provided key data and analysis insights to the working group, are included in Appendix B and formed much of the basis for this summary.[2]

To be clear, this report does not make new, long-term cost-of-energy forecasts. Instead, it is intended to inform the reader of future possibilities. The focus of the report is on onshore wind energy, as the vast majority of historical wind power investments have occurred on land. Offshore wind has yet to penetrate many of the world's commercial power markets and has not yet achieved the status of a mainstream source of power generation in much of the world. Nonetheless, useful analyses of past and possible future costs for offshore wind are available in the literature (e.g., Carbon Trust 2008, Ernst & Young 2009, UKERC 2010, Wiser et al. 2011, Levitt et al. 2011, ARUP 2011, and Doyle et al. 2011).[3]

[2] Individual presentations are referenced by author in the body of this report and included in the reference list.
[3] As a less mature technology and industry, offshore wind energy is at a different point on the technology development and deployment cost curve. Looking forward, offshore wind costs are generally expected to follow a steeper downward trajectory than costs for onshore wind energy (Neij 2008, Wiser et al. 2011, Doyle et al. 2011, and ARUP 2011).

2 Trends in Wind Energy Capital Costs and Performance

The cost of wind energy is a function of the cost to build and operate a wind energy project and the amount of energy produced by the facility over its lifetime. For the purposes of this report, the cost of wind energy is represented by the levelized cost of energy (LCOE). The LCOE is a simple way of comparing the unit costs of different generation technologies and is widely used in policy decision-making.[4] Additional detail on LCOE and methods for estimating it can be found in Schwabe et al. (2011). Precise estimates of the LCOE require detailed data on capital costs, financing costs, operation and maintenance (O&M) expenditures, and plant production data. However, detailed data across countries on each of these variables are often not in the public domain. The most detailed publicly available data sets often capture only capital cost and, in some cases, project performance data. Moreover, data on one or both of these two variables are available, over an extended time period, for only a handful of countries.

As a result of the aforementioned data limitations, independent capital cost and performance data have often been used historically as a proxy for the cost of wind energy. Reliance on these two variables as an indicator of the historical cost of wind is justified, in part, because they are two of the more significant contributors to the LCOE. However, because capital cost and performance are interdependent (e.g., newer, better performing technology sometimes costs more), reliance on only one of these variables may fail to fully explain historical (or forecast future) LCOE trends (e.g., EWEA 2009, Ferioli et al. 2009, Berry 2009, and Dinica 2011). This report includes data and analysis of both historical capital costs and project performance to inform our understanding of long-term cost trends and the high-level factors that influence the cost of wind energy. Moreover, the report does so with greater consideration for the interdependency between capital costs and project performance than has been typical in the past.

Here we examine capital cost and performance trends from the 1980s through present day. Capital cost data are broken into three different epochs, from 1980 to 2003, from 2004 to 2009, and from 2009 to projects planned for commissioning in 2012 and 2013. These time periods cover both significant cost reductions as well as the period of cost increases observed during the last decade. Included is a discussion of the drivers of both capital cost reductions and increases. Developments in turbine performance since the 1980s are also discussed; however, performance data are focused primarily on the more recent period, from the turn of the century to today's current turbine offerings.

2.1 Capital Cost Reductions: 1980–2003

From the 1980s to the early 2000s, average capital costs for wind energy projects declined markedly. In the United States, capital costs achieved their lowest level from roughly 2001 to 2004, approximately 65% below costs from the early 1980s (Wiser and Bolinger 2011). In Denmark, capital costs followed a similar trend, achieving their lowest level in 2003, more than 55% below the levels seen in the early 1980s (Nielsen et al. 2010) (Figure 1). Over the same time period, global installed wind power capacity grew from a negligible quantity to nearly 40,000

[4] It can be seen to represent a break-even cost per unit of energy produced for a generating facility and is typically based on the cost of capacity, operation and maintenance costs, the expected level of production, and financing costs as represented by a discount rate. LCOE typically does not capture or represent all societal costs or benefits resulting from wind energy deployment (e.g., grid integration costs and environmental externalities).

megawatts (MW) (GWEC 2006), with the bulk of this growth (>85%) occurring between 1995 and the early 2000s. The primary markets for wind energy during this time were Europe and the United States.

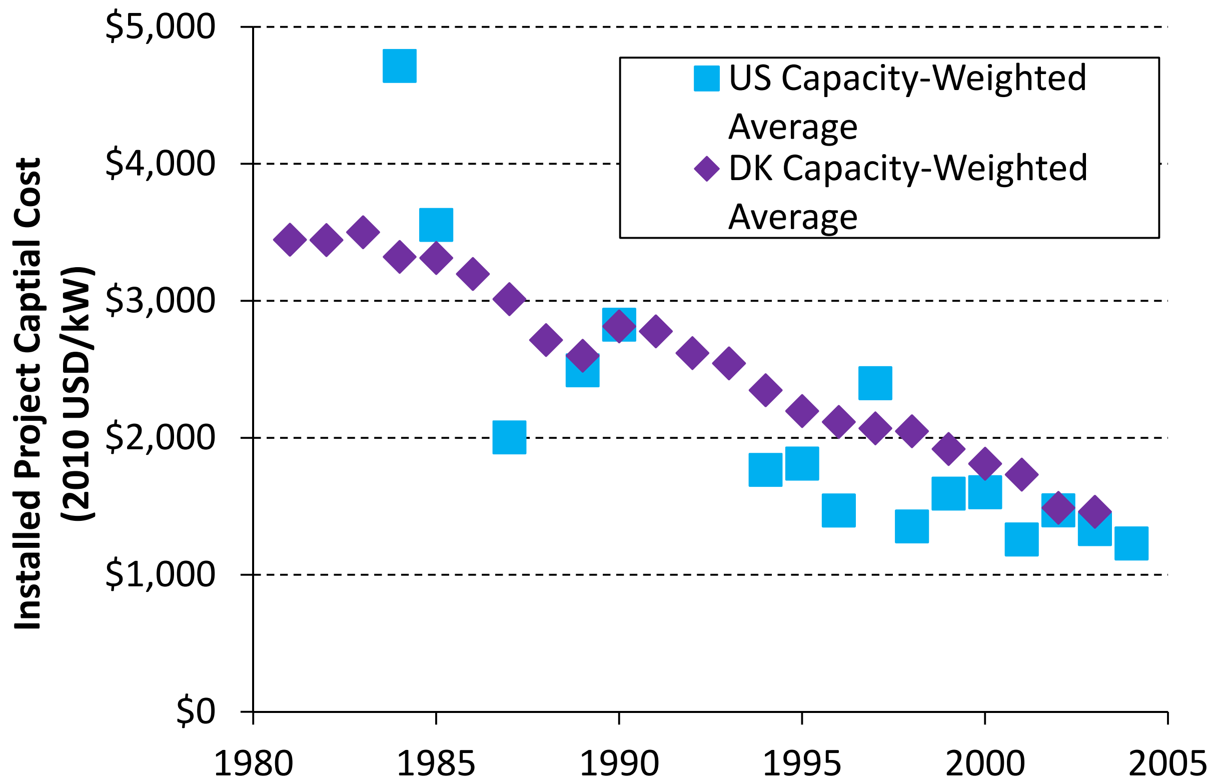

Figure 1. Capital cost trends in the United States and Denmark between 1980 and 2003

Sources: Wiser and Bolinger 2011, Nielsen et al. 2010

Over this time frame, technological innovations allowed for the development of larger turbines at lower costs. Economies of scale resulting from increased turbine size were followed by economies of scale in project size and manufacturing (EWEA 2009). More specifically, innovations in design, materials, process, and logistics helped to drive down system and component costs while facilitating turbine upscaling (EWEA 2009). Between 1980 and the early 2000s, commercial turbines grew from less than 100 kilowatts (kW) to more than 1 MW in capacity, rotor diameters grew from roughly 15 meters to more than 70 meters in some cases, and tower heights grew from 20 meters to more than 65 meters in some cases (Wiser et al. 2011). Larger turbines provided access to better wind resources while lowering the plant-wide parts count and generating turbine-level economies of scale for many components for which costs do not vary proportionally with turbine size (e.g., controls). For those components where costs tend to increase significantly with size, such as rotors, towers, and generators, engineering design innovations mitigated the otherwise-expected cost increases. Turbine upscaling also facilitated reductions in required project infrastructure, including roads, total project foundation costs, and underground cabling, helping to drive down balance of plant (BOP) costs on a dollars per kilowatt ($/kW) basis (EWEA 2009).

As costs declined and the technology matured, larger projects also began to emerge. These projects offered further potential economies of scale, this time in development costs, substation and interconnection infrastructure, transmission tie lines, and O&M facilities. Again, efficiencies were gained because these types of costs do not vary proportionately with project size (EWEA 2009). Finally, as the market expanded, greater production volumes allowed for investment in manufacturing facilities and created opportunities to increase production efficiencies, thus offering an additional source for capital cost reduction.

2.2 Capital Cost Increases: 2004–2009

The initial period of capital cost reductions came to an end in the early-to-mid 2000s. Data from the United States, Denmark, Spain, and Europe show capital cost increases beginning around 2004 and continuing through at least 2007–2009 (Figure 2). Capital costs in the United States were maintained at peak levels through 2010, although preliminary data indicate that capital cost reductions are likely in 2011, (see also Section 2.4) (Wiser and Bolinger 2011). In Denmark and Europe capital costs peaked earlier, in 2008 and 2007, respectively, and have declined modestly since then (see Figure 2 and Section 2.4).

An important exception to this general trend of substantially rising costs from 2004 to 2009 was China. Specifically, the emergence of a handful of strong domestic original equipment manufacturers (OEMs) has resulted in significantly lower capital costs in China (i.e., \$1,100/kW–\$1,500/kW [2010 U.S. dollars] in 2008–2009) than witnessed in Europe or the United States (Wiser et al. 2011b).

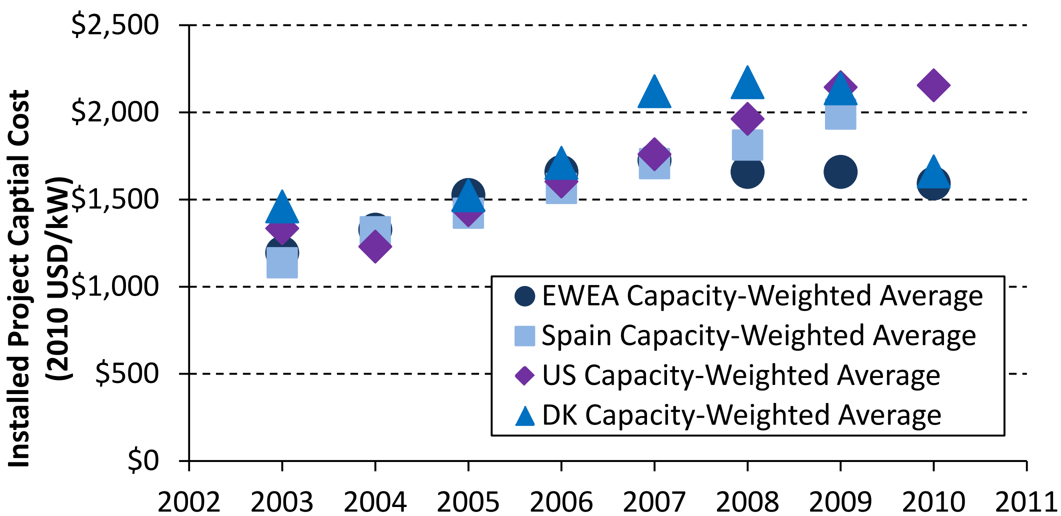

Figure 2. Capital cost trends in the United States, Denmark, Spain, and Europe from 2003 to 2009

Sources: Wiser and Bolinger 2011, Nielsen et al. 2010, Ceña and Simonot 2011, and EWEA 2011

Although balance-of-plant costs have played a role (e.g., Fowler 2008), the increase in capital costs observed between roughly 2004 and 2009 has been largely tied to increases in the price of wind turbines (Wiser and Bolinger 2011, Ceña and Simonot 2011). For example, Figure 3 depicts reported wind turbine transaction prices in the United States. Because visibility surrounding wind turbine transactions has declined in recent years, the figure also presents a range of reported pricing for U.S. transactions signed in 2010 and early 2011 and includes average global turbine prices reported by Vestas for the years 2005 through 2010. Leaving discussion of the sizable drop in turbine prices from 2009 to 2011 for Section 2.4, the figure clearly depicts the sharp rise in turbine pricing experienced during the mid-2000s.[5]

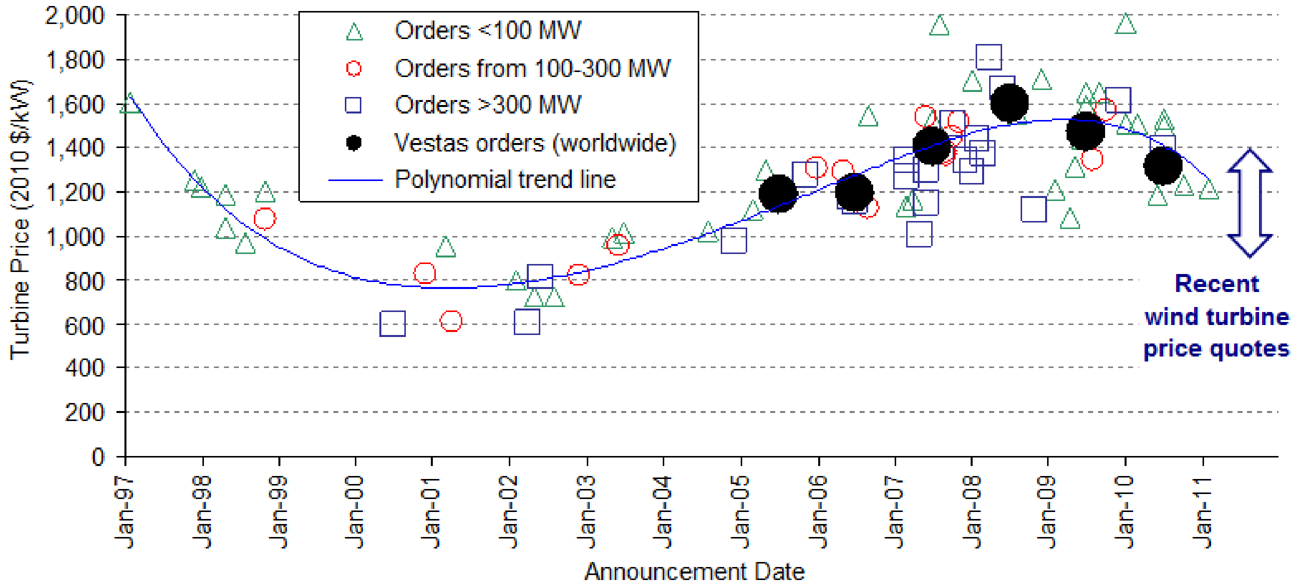

Figure 3. Wind turbine prices in the United States

Sources: Wiser and Bolinger 2011, Vestas (2011a, 2011, 2011c), and BNEF (2011a)

An array of factors has contributed to this increase in turbine prices. Raw material commodity prices and energy prices have been among the "exogenous" factors influencing capital costs over this time period. Both materials and energy prices increased substantially up to the time of the financial crisis in late 2008. Bolinger and Wiser (2011) estimate that materials price increases, including steel, iron, copper, aluminum, and fiberglass, resulted in an approximately $71/kW price increase for wind turbines in the United States from 2003 through 2008. Increases in energy prices were estimated to be responsible for an additional increase of about $12/kW (Bolinger and Wiser 2011). A similar Danish study (Nielsen et al. 2010) found that steel prices accounted for about $80/kW of the difference in Danish turbine prices over this same time period. Excluding steel, Nielsen et al. (2010) found that other raw material prices accounted for about $20/kW of the difference in Danish turbine prices from 2003 through 2008. Analysis of changing commodity prices in the Spanish wind industry suggest that changes in copper and steel pricing accounted for 46% and 34%, respectively, of the overall raw material cost increase of wind turbine nacelles from 2006 through 2010, while increases in the price of steel have been responsible for about 38% of the increase in the raw material cost of a typical wind turbine tower over this same time period (Ceña and Simonot 2011).

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[5] Other forms of electricity production equipment also experienced price increases over this same time frame (Chupka and Basheda 2007).

Growth from approximately 40,000 MW to nearly 200,000 MW of installed wind power capacity (GWEC 2011) in a period of about 6 years also resulted in significant supply constraints. Coupled with increasing OEM profitability and increasing labor costs, these constraints resulted in significant upward pressure on wind turbine prices. Analysis of the financial reports from the world's largest turbine manufacturer, Vestas, shows that manufacturer profitability grew notably from 2003 through 2008 and accounted for an estimated $106/kW of the increase in U.S. turbine prices during this time (Bolinger and Wiser 2011). Nielsen et al. (2010), using a slightly different methodology also based on Vestas financial reports, estimate an impact to turbine prices of about $125/kW over this time period. While these two particular quantitative estimates are based solely on data from Vestas, there is solid evidence that the profitability of other manufacturers also increased during this time (Bolinger and Wiser 2011). According to Nielsen et al. (2010), these higher earnings followed substantial price reductions associated with excess manufacturing capacity in the early 2000s, as well as financial losses that were accrued during the first half of 2000s.

In addition, Bolinger and Wiser (2011) found that growth in labor costs accounted for roughly $60/kW of the observed turbine price increase from 2003 through 2008 for Vestas, with similar results for Suzlon (Bolinger and Wiser 2011). Nielsen et al. (2010) estimate that the difference in labor costs from 2003 through 2008 was comparable, at about $50/kW. Though not quantified, additional upward pressure on turbine prices presumably came from the increased profitability and labor costs of component manufacturers. Supply chain bottlenecks also resulted in extended development lead times and placed additional upward price pressure on (non-turbine) BOP costs. Nielsen et al. (2010) observed that the rapid increase in demand for turbines from 2005 resulted in supply side constraints for key components such as bearings and gear boxes, and that these constraints may have been compounded by sub-contractors who optimized their production to smaller wind turbine models that dominated the market up until 2005.

Continued turbine upscaling and increasingly sophisticated designs have also resulted in turbine price increases due to increased material use, more complex control and sensing systems, and enhanced power conversion capabilities (Wiser and Bolinger 2011). Using an NREL scaling model described in Fingersh et al. (2006), turbine upscaling alone—not considering other design advancements, which have also improved the performance of modern turbines and resulted in improved grid interactions—has been estimated to be responsible for $114/kW of the turbine price increases observed from 2003 to 2008 in the United States, representing the single largest factor driving prices higher over this time period (Bolinger and Wiser 2011). Over the time period from 2006 through 2010, Ceña and Simonot (2011) attribute upwards of 50%–70% of individual nacelle, blade, and tower raw material cost increases to the impacts of increased material use (weight) in the larger turbines of today. Focusing solely on steel costs, Nielsen et al. (2010) estimated that the structural strengthening required to accommodate larger rotors and higher towers alone resulted in additional cost for wind turbines of approximately $60/kW when comparing turbines built in 2003 with those in 2008. As shown in Bolinger and Wiser (2011), however, the increased capital costs due to upscaling have been rewarded by higher energy yields. Excluding other drivers of turbine prices, upscaling was estimated to yield a lower turbine-level LCOE, despite the increase in capital cost associated specifically with upscaling. This highlights the interdependence of capital cost and performance.

Manufacturer warranty provisions also increased over this time period. Estimates by Bolinger and Wiser (2011) indicate that Vestas' increases in warranty provisions were responsible for \$31/kW of wind turbine price increases from 2003 through 2008, with strong evidence that other manufacturer warranty provisions were also increasing over this time period. For wind power markets outside of Europe, exchange rate fluctuations may have also contributed to increases in observed turbine prices. In the United States, for example, the declining value of the dollar relative to the Euro was estimated to have been responsible for \$87/kW of the total observed increase in turbine prices from 2003 through 2008 (Bolinger and Wiser 2011). As markets outside of Europe have begun to build up their own domestic manufacturing capacity, however, fluctuations in exchange rates will likely have a less significant impact on turbine prices and subsequently capital costs moving forward.

Further discussion and analysis of the role of some of these factors in driving historical onshore wind energy costs is included in Milborrow (2008), Blanco (2009), and Dinica (2011). Moreover, other authors note the importance of many of these same factors in driving up the cost of offshore wind energy (e.g., Carbon Trust 2008, Greenacre et al. 2010), as well as other forms of electricity generation equipment (e.g., Chupka and Basheda 2007, Winters 2008) over a similar time frame.

2.3 Performance Increases: 1980–2010

To maximize turbine performance, manufacturers have sought to develop more advanced turbine components and larger turbines. More advanced components promise greater efficiency, improved availability, and reduced generation losses (EWEA 2009, Wiser et al. 2012). Scaling to taller towers allows wind turbines to capture less turbulent and often stronger wind resources. Meanwhile, larger turbine rotor diameters allow a turbine to generate more electricity than would otherwise be the case. In Figure 4, the growth of turbine nameplate capacity, hub height, and rotor diameter, over the past 30 years is illustrated.[6]

[6] The development of larger turbines may not result in an increased ability to extract energy from a fixed amount of wind energy, and as such, scaling does not improve turbine efficiency. However, by increasing the energy production of a given turbine, which requires innovations in rotor design, tower design, the drivetrain, and transport logistics, turbine scaling and the development of larger turbines is a technological change that has advanced the state of the art.

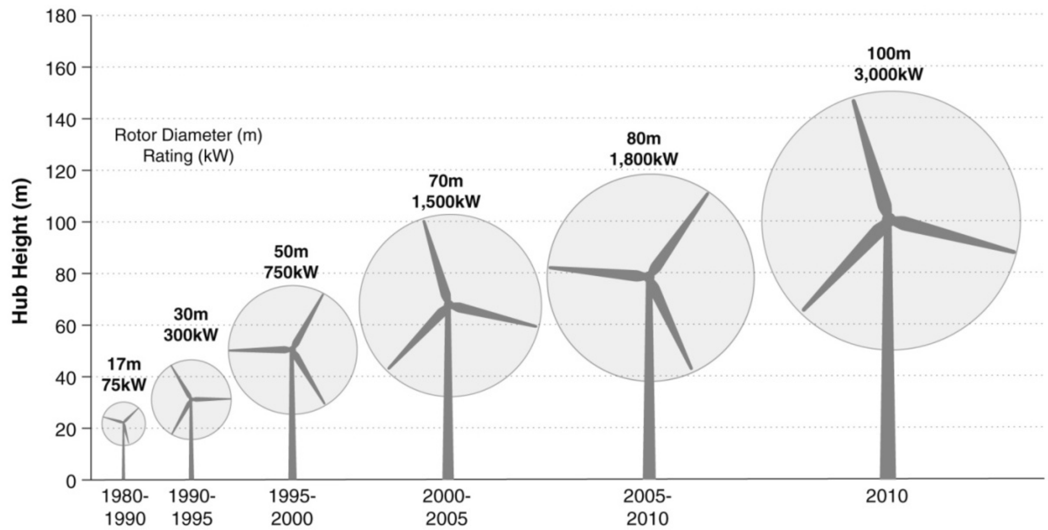

Figure 4. Representative turbine architectures from 1980 to 2010

Source: NREL

A review of annual fleet-wide capacity factor data for the United States, Denmark, and Spain, spanning 1999 through 2010, demonstrates the resulting performance improvements, to some degree (Figure 5). Specifically, data for the United States and Denmark demonstrate overall increases in average fleet-wide capacity factors on the order of 20% or more over this period. However, such data are often confounded by inter-annual wind resource variability, dispatch curtailment due in part to transmission congestion,[7] and long-term trends toward siting projects in lower wind resource areas as the best resource sites are developed. The latter variable has been especially significant in Spain, where fleet-wide capacity factor data show relatively flat—and to some extent, declining—capacity factors as a result of new developments being pushed to lower quality wind resource areas, simply because they are the only readily developable sites that remain.

[7] Although not shown in the data in Figure 5, this latter issue has emerged in the United States in certain regions (Wiser and Bolinger 2011).

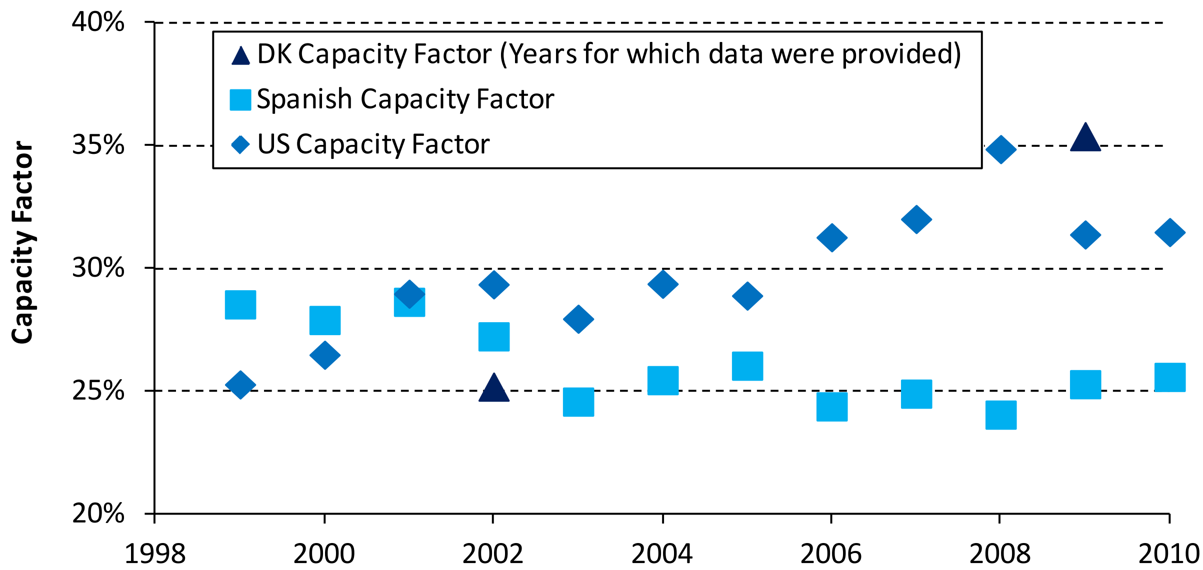

Figure 5. Fleet-wide capacity factor data for the United States, Denmark, and Spain from 1999 to 2010

Source: Wiser and Bolinger 2011, James-Smith 2011a, and Mesa 2011

Note: U.S. data for 2007, 2008, 2009, and 2010 are estimated based on actual production plus estimated curtailment (where curtailment data are available).

As a result of the limitations noted above, fleet-wide capacity factor data are incapable of demonstrating the true level of performance improvement achieved over the past three decades. However, by evaluating overall multi-year average capacity factor changes within specific wind power classes and for specific project vintages, greater insights into the overall magnitude of technical improvement can be gained. Such an exercise is particularly important in places like Spain (and many other parts of the world) where projects have increasingly been installed in lower wind power class sites, and the actual degree of capacity factor improvement over time within individual wind resource classes is less apparent (Wiser 2011, Dinica 2011).[8] Figure 6 illustrates the substantial improvements over time in multi-year average capacity factors that have been observed from projects installed in the United States when sorted by wind power class and project vintage. These improvements have been directly linked to the development of taller towers and larger rotors (Wiser 2010). In addition, by relying on modeled performance of representative turbines installed between the early 2000s to today, Wiser et al. (2012) show improvements in capacity factor on the order of 20% for projects in Class 5 and Class 6 wind regimes and as much as 50% for projects in mid-Class 3 wind regimes (see Figure 7).

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[8] Aside from resource exhaustion as has been observed in Spain, drivers of project siting in lower wind resource class areas could also include limited transmission availability, environmental and wildlife exclusions, and potentially social opposition, among other siting limitations.

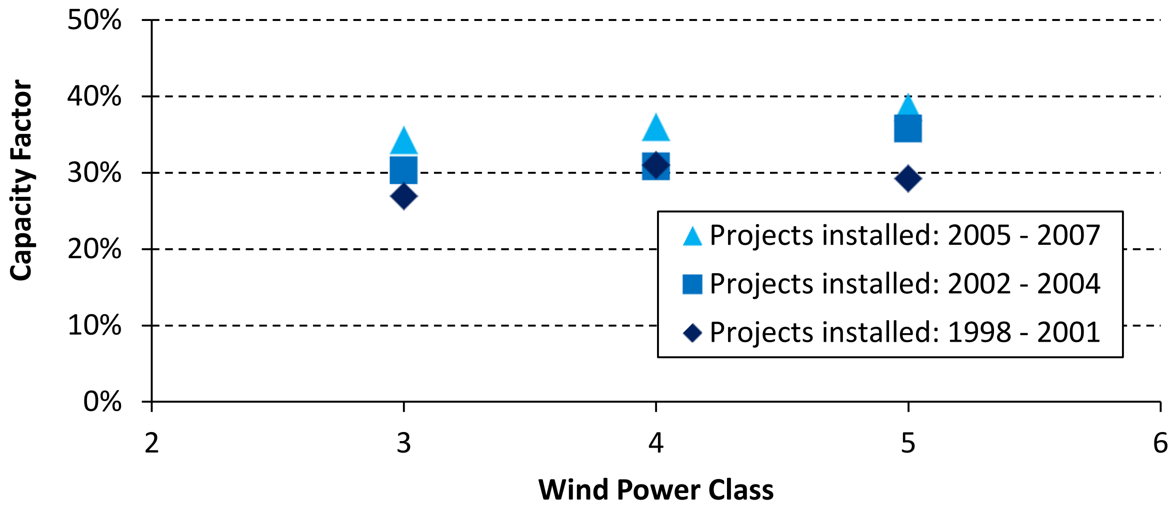

Figure 6. U.S. project capacity factors by vintage and wind power class

Source: Wiser 2010

Using a different but related metric for wind power plant performance, annual energy production per square meter of swept rotor area (kilowatt-hour [kWh]/m^2) for a given wind resource site, improvements of 2%–3% per year over the last 15 years have been documented (IEA 2008, EWEA 2009).[9]

[9] These data suggest that turbines are not only capturing more energy as a result of scaling but are also becoming more efficient.

2.4 Recent and Near-term Trends in Capital Cost and Performance

Since the financial crisis of late 2008, global turbine production capacity has increased while demand in some markets has softened. In combination with a shift in the directional impact of many of the turbine price drivers discussed in Section 2.2 (e.g., commodity or raw materials prices and manufacturer profitability), the result has been significant turbine price declines (see Figure 3). Declining turbine prices (as well as BOP costs) began to reduce average capital costs in some markets as early as 2008 (e.g., Denmark), but other markets took more time to work through higher cost inventory that was contracted before prices began to fall (e.g., the United States).[10] Data from Denmark show that capital costs fell about 2% from 2008 to 2009, and then by more than 22% between 2009 and 2010 (Nielsen et al. 2010); EWEA estimates an 8% reduction from 2007 through 2010 in the whole of Europe (EWEA 2011) (see Figure 2). Analysts expect capital cost reductions of this magnitude to follow in the near term for the United States (Wiser et al. 2012, Wiser and Bolinger 2011)[11] and elsewhere, perhaps with some exceptions and variability in the overall magnitude of capital cost reduction. Capital cost expectations farther into the future suggest continued declines (See Section 4).

Despite the recent decline in turbine prices, hub heights and rotor diameters have continued to trend toward larger machines, suggesting that turbine performance improvements will also continue. Preliminary analysis conducted by Wiser et al. (2012) suggests that capacity factors for projects to be installed with current state-of-the-art technology in the United States ("Current: 2012-13" in Figure 7) will improve significantly within a given wind power class, relative to older technology (Figure 7). Moreover, also shown in the figure, the most significant performance improvements are occurring in equipment designed for low wind speed sites (typical average hub-height wind speeds of 7.5 m/s).[12] As a result of these technical and design advancements, Wiser et al. (2012) find that the amount of U.S. land area that could achieve 35% or higher wind project capacity factors has increased by as much as 270% when going from turbines commonly installed in the 2002–2003 time frame to current low wind speed turbine offerings.

[10] In the United States, turbine lead times approached 2 years during the peak demand period in the first half of 2008. Market fundamentals have since changed, and lead times have dropped significantly. Nevertheless, there is a natural lag between turbine contract and power purchase agreement signing and project commissioning such that turbines ordered in early 2008 were still working their way through projects that were completed in 2010.

[11] Initial 2011 data for the United States indicate that average project capital costs will likely fall relative to 2010, while greater cost reductions are expected for projects to be completed in 2012–2013, based on current turbine orders.

[12] As previously noted, performance improvements may not actually result from increased turbine or rotor efficiency but rather from new equipment that can access more valuable wind regimes as a result of higher hub heights and capture more energy as a result of larger rotors.

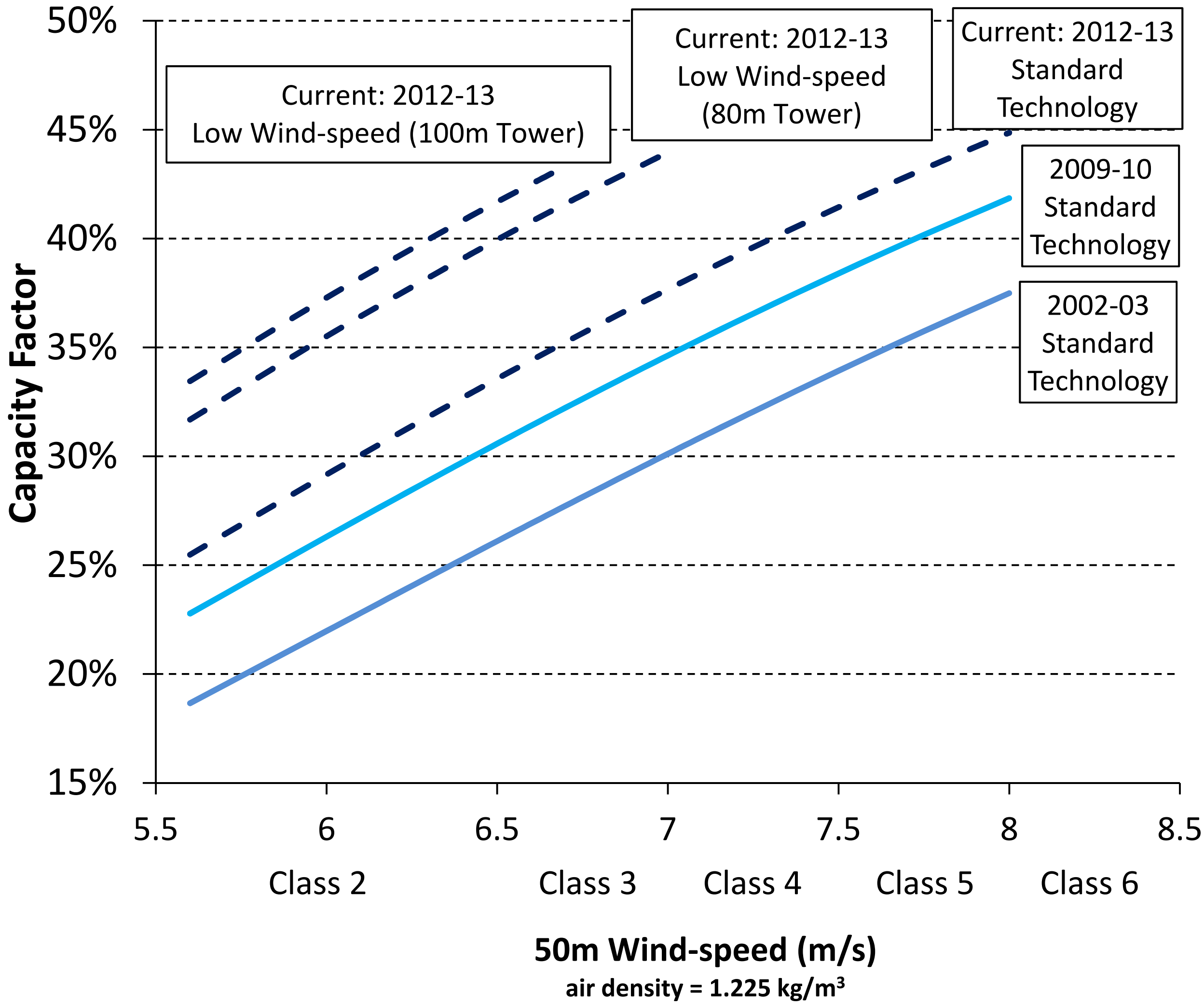

Figure 7. Modeled capacity factors for current turbine models relative to historical technology

Source: Wiser et al. 2012

Note: Low wind speed turbines are generally certified for IEC Class III wind conditions. IEC Class definitions are distinct from and independent of the Wind Power Classes noted in the figure. IEC standards define the reference average annual hub height wind speed for Class III machines as 7.5 m/s at an air density of 1.225 kg/m^3*. Although site-specific factors (e.g., turbulence, gust conditions, air density) ultimately determine the viability of a specific turbine at a particular site, Wiser et al. use the 7.5 m/s (at an air density of 1.225 kg/m*^{3}*) reference as the maximum average annual wind speed at hub height for these machines.*

3 Impact of Capital Cost and Performance Trends on Levelized Cost of Energy

As noted earlier, attempting to elicit LCOE trends from either capital cost or performance independently is tenuous. Both variables are important components of the overall LCOE equation. Historical and near-term LCOE trends are highlighted in this section to demonstrate the value of focusing on LCOE and the shortcomings associated with having an exclusive focus on either capital cost or performance. Data shown here generally reflect the impact on LCOE from capital cost and performance changes. More precise estimates would also factor in the effects of changes in O&M costs, major equipment replacement costs, financing costs, and actual turbine lifetime. However, due to limited data availability, the latter variables were not considered in the analysis presented in Section 3.2. Also note that the LCOE figures presented in this section exclude available incentives that might affect the price of wind energy in wholesale markets.[13]

3.1 Historical LCOE Trends: 1980–2009

Significant reductions in capital cost and increases in performance between 1980 and 2003 had the combined effect of dramatically reducing the LCOE of wind energy. Data from three different historical evaluations, including internal analysis by the Lawrence Berkley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) as well as published estimates from Lemming et al. (2009) and DEA (1999), illustrate that the LCOE of wind power declined by a factor of more than three from more than $150/MWh to approximately $50/MWh over this period (Figure 8). During this time, capital cost and performance trends were both generally aligned with substantial capital cost declines and performance improvements. As a result, there was little risk associated with an exclusive focus on one or the other when attempting to understand broad trends in the LCOE of wind.[14]

The increase in capital cost observed between 2004 and 2009, however, pushed the LCOE upward despite the continued performance increases noted during this period (see Section 2). The observed increase in LCOE was mitigated to some extent by performance increases, however, and the overall LCOE trend is only modestly upward within the broader historical timeline depicted in the figure. In fact, as discussed earlier, the single largest (but certainly not the only) driver for the increased capital costs over this period was turbine upscaling (Bolinger and Wiser 2011), which was rewarded with performance improvements. Clearly, from 2004 to 2009, an exclusive emphasis on either performance or capital costs to understand the trends in the cost of wind energy would have been misleading. In the former case, one would have assumed costs would have continued to fall due to performance increases, while in the latter instance, one might have assumed that the LCOE increases would have been more dramatic than they ultimately were.

[13] In the United States, this is primarily the production tax credit, which is not accounted for in the data below. To the extent that other industry support schemes (e.g., feed-in-tariffs and renewables obligations certificates) might also affect the price of wind energy, they are not captured here.

[14] Of course, an accurate estimate of actual LCOE trends would have required an assessment of both factors, as both were improving over this period.

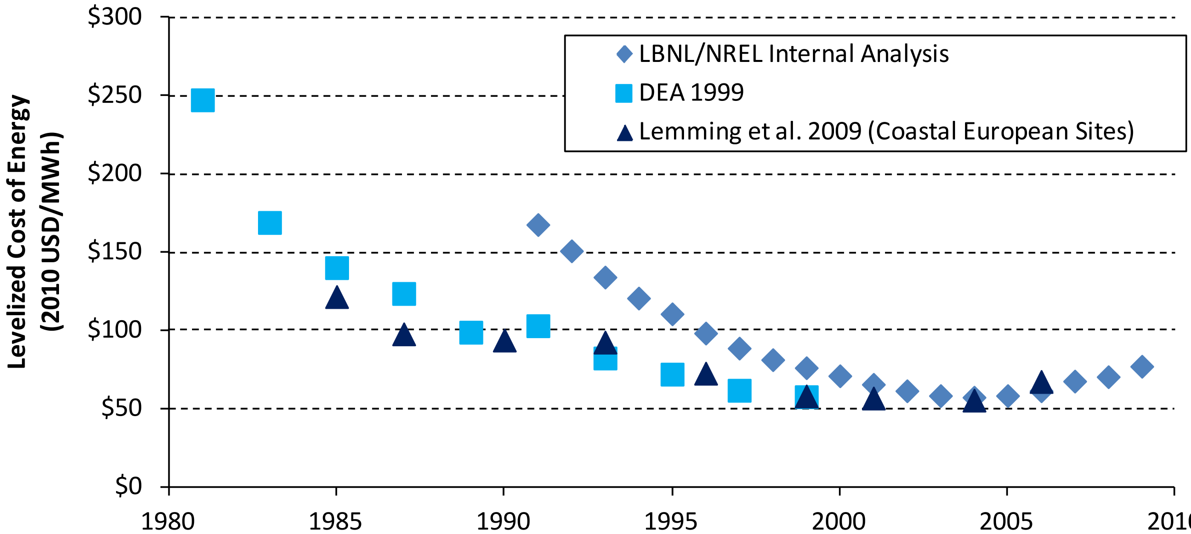

Figure 8. Estimated LCOE for wind energy from 1980 to 2009 for the United States and Europe (excluding incentives)

Sources: LBNL/NREL (internal analysis), Lemming et al. 2009, and DEA 1999

3.2 Recent and Near-term Trends in LCOE: 2010–2013

Turbine prices and therefore project capital costs have recently declined since their peak in the late 2000s, but turbine pricing and capital costs have not returned to the historical lows observed earlier in the 2000s. Despite this, continual improvements in turbine technology are expected to result in the industry achieving an apparent historic low in the LCOE of wind, particularly in low and medium wind speed sites (i.e., 6.0 m/s to 8.5 m/s average annual hub-height wind speed) (Wiser et al. 2012, James-Smith 2011b).

Applying capital cost and performance data from the United States and Denmark, along with standard industry assumptions derived from historical data and industry inquiries for O&M and replacement costs, financing costs, and project availability, Figure 9 illustrates the results of two analyses completed by the IEA Task 26 working group.[15] Both these LCOE estimates rely on the same cash flow model used previously by the IEA Task 26 working group model and described in detail in Schwabe et al. (2011). The results show that the LCOE of wind increased from 2002 to 2009 as a result of capital cost increases that outweighed the performance improvements otherwise experienced over that time frame. In comparison, current turbine offerings (i.e., those that might be installed in the 2012–2013 time frame) also have higher project-level installed

[15] The turbine technologies considered in these two analyses include the GE 1.5/1.6 series machines in the United States analysis and the NEG Micon NM52/90, Siemens 2.3-93, and Vestas 3.0 V112 turbines in the Danish analysis. Capital costs range from $1,300/kW to $2,150/kW depending on the commercial operation date, local market conditions, and whether low wind speed turbines are considered (low wind speed turbines are only considered in 2012–2013 for those wind speed classes where they are IEC certified and are somewhat higher in cost than their "standard technology" analogs). Turbine production varies based on the technology being considered and, of course, the average annual wind speed. A complete description of technology, cost, and performance modeling inputs as well as the constants utilized for annual operations expenditures and financing costs is included in Appendix A.

costs than those installed in 2002–2003, but those costs are lower than in 2009–2010 and are more than offset by the sizable expected performance improvements, yielding a lower LCOE than in 2002–2003, despite the higher capital costs.

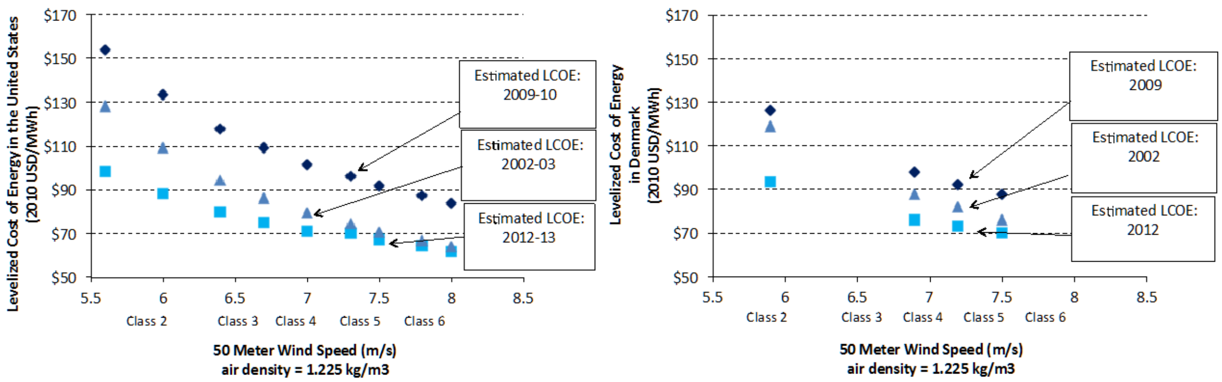

Figure 9. LCOE for wind energy over time in the United States (left) and Denmark (right)

Sources: Wiser et al. 2012, James-Smith 2011b

Note: Estimates assume low wind speed turbines are utilized at sites with ≤7.5m/s equivalent sea level annual average hub height wind speed for 2012–2013 only. All other estimates are based on modeled performance for standard industry technology during each time period. Estimates also exclude available incentives and policies that might reduce the price of wind energy in wholesale power markets. Finally, these estimates assume constant standardized industry values for O&M, financing costs, and losses.

Looking ahead, because LCOE is the primary cost metric that impacts the bottom line of project owners, utility purchasers, and to some extent even society at large (although, of course, not all societal costs are captured in the LCOE), it is justified that analysis of future wind energy costs be based on estimates of LCOE rather than capital cost alone. Moreover, unlike between 1980 and the early 2000s when both performance and capital cost trends suggested significant reductions in the cost of wind energy, the technology is now at a point where an optimal cost of onshore wind energy may result from little or no further capital cost reductions (and perhaps even modest capital cost increases), but continued performance improvements.[16] Continued incremental optimization on a cost or performance basis, as is likely into the future, is expected to require analysis of future cost based on LCOE.

Aside from simple technological maturation, the potential for limited capital cost reduction is further justified by the current trend of OEMs to offer a suite of turbine designs, including an increasing number of offerings that are specifically designed for lower wind speed sites. Low wind speed turbines typically have higher hub heights and larger rotors (in comparison to their capacity rating), necessarily resulting in a higher capital cost product. But those capital cost increases are rewarded by improved performance and, in many instances, a lower LCOE than standard turbine offerings that feature smaller towers and rotors. In fact, as shown in Wiser et al. (2012), by generating more significant performance increases in the emerging fleet of low wind

[16] Simultaneous reductions of capital cost and performance improvements do remain a possibility, albeit increasingly unlikely.

speed turbines, the difference in the LCOE of wind between low to medium wind speed sites and high wind speed sites has declined over time (Figure 10). As a result of the improved economics of wind and this narrowing in the LCOE between lower and higher wind speed sites, an increasing amount of land area has become economically viable for wind energy development. In the United States, for example, the available land area capable of generating wind energy at an unsubsidized cost of $62 per megawatt-hour (MWh) (2010 U.S. dollars) is estimated to have increased by 42% relative to the land area capable of producing power from wind at this cost in the early 2000s (Wiser et. al. 2012).

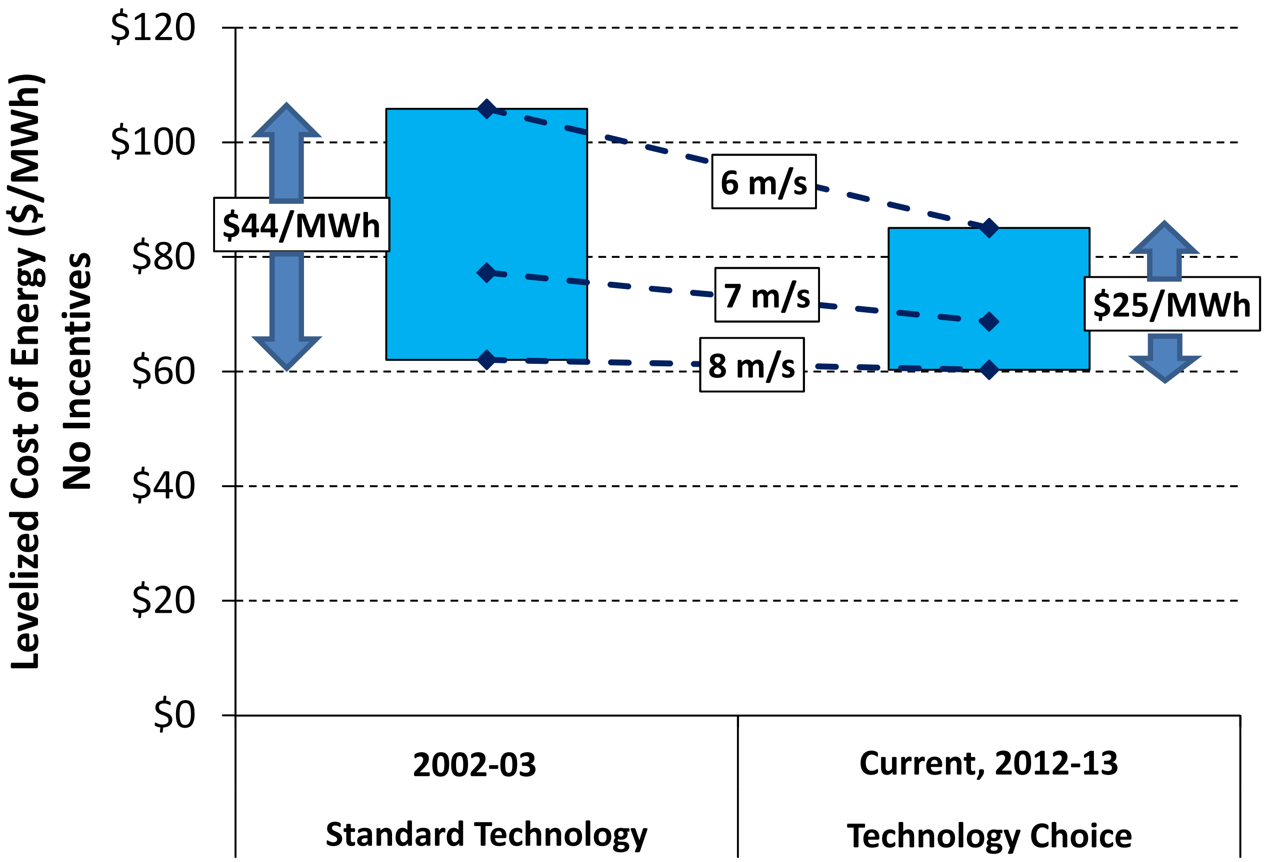

Figure 10. Estimated change in the LCOE between low and high wind speed sites resulting from technological advancement

Source: Wiser et al. 2012

Note: Today's turbine offerings include typical standard technology with an IEC Class I/II rating as well as low wind speed technology designed for IEC Class III sites. Wind speeds noted here are average annual sea level equivalent wind speeds at 50 m. "Technology Choice" signifies the lowest cost turbine for a given wind regime. At average annual hub height wind speeds below the sea level equivalent of 7.5 m/s, Technology Choice results in the use of low wind speed technology.

4 Analytical Methods to Project the Future Cost of Wind Energy

A historical perspective provides a great deal of insight into the trajectory of the industry and likely near-term trends (2–5 years), as well as an understanding of the driving forces behind past and therefore potential future cost trends. However, the historical perspective alone fails to reflect the specific technologies that remain in the research and development (R&D) pipeline and may not adequately reflect the temporal nature of future cost reductions, which are likely to depend on the rate of deployment and the amount of public and private sector R&D invested in technology development. To complement an analysis of historical trends, three analytical methods, the learning curve, expert elicitation, and the engineering model, have been developed to provide additional insights into the future cost of wind energy over periods beyond the immediate future.

This section examines the strengths and weaknesses of each of these three methods, highlights examples of each as applied today, and summarizes the results of an array of studies utilizing one or more of these methods to project the cost of wind energy through 2030. It also discusses potential sources of future cost reductions, primarily focusing on changes in wind turbine technology anticipated to reduce initial costs and operations expenditures and/or increase turbine performance.

4.1 Learning Curve

The learning curve methodology has been the most common approach to forecasting future wind energy costs. This approach assumes an explicit cost reduction, typically calculated from historical trends, as a function of technology deployment or, in some cases, equipment production. By using a learning curve, a specific learning rate, or percentage reduction associated with every doubling in the capacity of installed wind energy projects, can be calculated. The estimation of a historical learning rate is not in itself a projection, but rather a means of evaluating historical trends (Lemming et al. 2009). Nonetheless, learning rates derived from historical trends are commonly used to forecast future costs. A recent review of 18 estimates of learning rates for onshore wind energy, completed for the Intergovernmental Panel on Climate Change Special Report on Renewable Energy (Wiser et al. 2011), found that the overall range of learning rates available in the published literature varied from 4%–32%. However, by focusing on a more limited sample of studies conducted since 2004 and using common variables (e.g., global installations and total investment costs) the range was narrowed to 9%–19%.

The broad range of learning rates derived from past analysis suggests that a few caveats are necessary when interpreting learning rates and using them to forecast future wind energy costs. With respect to assessing previously calculated learning rates, the boundaries of a given study are important. As the wind industry has only recently become truly global, many past studies focused on deployment within a given country or regional market (e.g., Neij 1997, Mackay and Probert 1998, Wene 2000, and Söderholm and Sundqvist 2007). Today, however, the wind industry serves a multi-billion dollar global market and provides manufacturers and installers with opportunities to learn from technology improvements and installation efficiencies from around the world. Cost reductions used to calculate learning rates should therefore ideally be associated with global installations—not simply those in a specific local market (Ek and

Söderholm 2010).[17] Boundaries around the time period of historical data used are also critical. For example, including data from 2002 to 2009 (which observed price increases due to a range of factors discussed earlier) will produce a lower learning rate than if the rate were only calculated from data that extends to the early 2000s; whether or not using 2002–2009 data is appropriate depends on the nature of the drivers that impacted wind energy costs during that period.

The dependent variable that is studied will also impact the results of a learning curve study. Data limitations have resulted in learning curve studies that frequently used project capital costs or turbine prices as the dependent variable and as a proxy for wind energy costs, as opposed to the LCOE. However, as discussed in Section 3, if capital costs are flat or increasing, but performance is also increasing, reductions in LCOE could be occurring that are not reflected in capital cost trends. Use of a dependent variable other than LCOE could potentially distort the true learning rate for the technology (EWEA 2009, Ferioli et al. 2009, and Dinica 2011).

Finally, learning rates used to estimate future costs would ideally also be adjusted to account for cost reductions resulting from drivers that are unrelated to cumulative installed capacity. For example, cost reductions may result from a targeted R&D investment, economies of scale, market supply and demand forces, or changes in commodity prices, all factors that are not necessarily affected by learning associated with industry maturation and increased deployment. Unless such variables are accounted for when estimating a learning rate (which results in a lower learning rate) or can be assumed to provide equivalent cost reductions into the future, future projections may overestimate the level of cost reduction associated with a specific increase in total installed capacity (Wiser et al. 2011). Even when controlling for such variables, however, declining returns are possible (Ferioli et al. 2009, Nemet 2009), and an assumption that past learning rates can be applied to forecast future costs may be suspect.

4.1.1 Future Onshore Cost Estimates from Learning Curves

Despite their limitations, learning curve techniques can be informative with respect to the general magnitude of possible future cost reductions. Learning curves are likely to remain in use due to their relatively basic analytical underpinnings, reliance on real historical data, limited data requirements, and the lack of obvious alternatives, particularly when looking more than a decade into the future. As a result, the European Wind Energy Association (EWEA) and many others, including governments, have relied extensively on learning curves to project the cost of wind energy into the future. Often studies that apply learning curves and rates include external assumptions that adjust for some of the limitations noted above by, for example, assuming a reduction in the learning rate over time or only applying the learning curve for a short period of time (e.g., EWEA 2009). Others focus the use of learning exclusively on capital costs and assume little or no improvement in wind project performance (e.g., IEA 2009, Lemming et al. 2009), while still others apply the assumed learning rate to LCOE estimates (EWEA 2009).

Based on a range of learning curve estimates for LCOE of 9%–17%, EWEA (2009) used a learning rate of 10% to estimate that LCOE would drop by roughly 1–2 euro cents/kWh between 2010 and 2015. Using three different learning rates that are assumed to fall with deployment and

[17] If a given cost reduction that is the result of learning by a global industry is attributed to only a fraction of global installations, and represents a national or regional market, the degree of cost reduction resulting from a given set of installations can be over or underestimated. As a result, errors can be introduced into both historical comprehension and projections.

industry maturation from 10% to 6%, and ultimately to 3%, in order to represent the diminishing returns associated with increased deployment, Lemming et al. (2009) estimate that wind energy capital costs will fall by approximately 20% by 2020 and 30% by 2050 while capacity factors remain at current levels. The Global Wind Energy Council (GWEC) and Green Peace International (GPI) (GWEC/GPI 2010) utilize a learning rate and variable deployment rates to estimate that capital costs will fall by 10% to 20% between 2010 and 2030. IEA (2009) applied a 7% learning curve to land-based wind energy to determine that capital costs will fall by nearly 20% by 2030 and 25% by 2050.

By and large, institutions using learning rates to project future costs have often tended toward relatively conservative assumptions and largely arrived at capital cost reductions on the order of 20%–30% by 2030 with somewhat smaller, incremental cost reductions accruing through to 2050. A review of learning rates in the literature conducted by the IEA Task 26 working group suggests that the most aggressive use of learning rates in the literature results in a reduction in the LCOE from wind power on the order of 30%–40% by 2030 (see Section 4.5).

4.2 Expert Elicitation

To bolster the reliability of learning curve estimates and to garner a more detailed understanding of how future cost reductions may actually be realized, analysis of the future cost of wind energy also sometimes includes expert elicitation. This approach is based on surveying or interviewing industry executives and technology design experts. Interviews are typically focused at the turbine component and system level and may also attempt to capture trends in various aspects of installation costs (e.g., underground cabling, erection costs, and required on-site monitoring infrastructure). By evaluating the potential for cost reductions or performance improvements at the component or system level and combining the estimated potential from an array of concrete possible technological advancements, this approach constitutes a simple but technology-rich, bottom-up analysis. In fact, expert elicitation is unique in that it allows for a relatively simple bottom-up analysis and for a diverse set of variables (i.e., market pressures or system-level turbine interactions) to be considered. However, it also introduces a relatively high level of subjectivity into the analysis, as the responses to the elicitation may be affected by the design of the data collection instrument and by the individuals selected to submit their views through that instrument.

4.2.1 Examples of Expert Elicitation

Expert elicitation is sometimes combined with learning curve analysis and may be used to inform public sector R&D investments. In the latter case, explicit quantitative projections may or may not be included, but expert interviews are utilized to identify specific areas where focused R&D is likely to have the greatest impact on the future cost of energy. The European wind industry, with funding from the European Union, has used the expert elicitation approach in its European Wind Energy Technology Platform (TP Wind) to identify specific research priorities. The U.S. Department of Energy's study *20% Wind Energy by 2030* (U.S. DOE 2008) utilized the expert elicitation derived from insights in the Wind Partnership for Advanced Technology Components (WindPACT) design studies (e.g., Cohen et al. 2008) to estimate an approximately 10% reduction in wind energy capital costs and a nearly 20% increase in capacity factors (36%–43% in a Class 4 wind resource) between 2005 and 2030. Neij (2008), in work conducted for the European Union's New Energy Externalities Developments for Sustainability (NEEDS) project, combined expert elicitation with learning curve analysis to estimate that future turbine costs could be approximated with a learning rate of about 10% and that reductions in the LCOE could be approximated with a 15% learning rate when accounting for increased performance. Although applied to offshore wind, Junginger et al. (2004) combine a sophisticated learning curve approach (i.e., estimating learning curves for individual turbine components) and expert elicitation to estimate future offshore wind energy cost reductions.

4.3 Engineering Model

Similar to expert elicitation, engineering modeling analysis provides a bottom-up alternative or complement to the learning curve. Rather than relying on high-level data or expert opinion, this approach utilizes detailed modeling of specific possible technology advancements that are expected to result in cost reductions or performance increases. Because this approach typically models both cost and performance, it inherently emphasizes expected reductions in LCOE. It also requires a relatively robust understanding of possible technology advancements and, as a result, the opportunities captured by engineering studies are often incremental and generally realizable in the near term (5–10 years).

In addition to primarily being focused on the near to medium term, the main limitation of the engineering model approach is that it requires highly sophisticated design and cost models to capture the full array of component- and system-level interactions. Often the level of sophistication achieved with today's modeling tools is insufficient to truly capture the system-level interactions that are common in wind turbine design. Cost models are also unable to make projections about future commodity prices or supply and demand pressures throughout the supply chain (of course, learning curves and expert elicitation face similar challenges).[18] Accordingly, the projected costs are generally based on the impact of a particular technical innovation, all else being constant.

4.3.1 Engineering Model Examples

One of the prime examples of the engineering modeling approach comes from the U.S. Department of Energy's WindPACT project (e.g., Bywaters et al. 2005, Malcolm and Hansen 2002). Under that project, an array of system design studies was used to understand how various innovation opportunities might affect turbine performance into the future. These results were ultimately tied to cost functions to quantify their impact on turbine and project costs (Fingersh et al. 2006). More recent NREL modeling work that builds upon these studies suggests that performance increases on the order of 20% and cost reductions on the order of 10% over the next one to two decades are possible but may require additional technological advancements not captured by the WindPACT studies (e.g., Lantz and Hand 2011). Another example of the engineering modeling approach being applied to future costs is in the European Commission's *UpWind* project. In this effort, technical experts identified and analyzed an array of actions required to achieve a functional 20-MW turbine, and cost modeling was used to estimate the potential cost of this machine and the impact to costs from the various technological enhancements (UpWind 2011).

[18] Of course cost models are able to analyze the impacts of changes in commodity prices and labor costs, they simply cannot forecast or anticipate such changes.

4.4 Sources of Cost Reduction Identified by Expert Elicitation and Engineering Modeling Assessments

Incremental innovations in a variety of aspects of wind turbine design as well as in turbine erection, O&M strategies, and manufacturing are expected to contribute to reduced wind energy costs in the future. Table 1 summarizes the broad categories of opportunities envisioned to apply to onshore wind energy projects, based on engineering studies and expert elicitation. Much of the opportunity to drive down costs is perceived to be in the design and performance of wind turbines because of their critical role in calculating wind energy's LCOE; initial turbine expenditures alone account for roughly 70%–75% of project capital costs (Wiser and Bolinger 2011, Blanco 2009) and about 60% of lifetime project costs (Blanco 2009). However, O&M strategies and manufacturing efficiencies are also anticipated to help reduce the cost of wind energy in the future.

Table 1. Potential Sources of Future Wind Energy Cost Reductions

R&D/Learning Area	Potential Changes (For more detail on technology changes and expected impacts, see references below)	Expected Impact
Drivetrain Technology	Advanced drivetrain designs, reduced loads via improved controls, and condition monitoring (Bywaters et al. 2005)	Enhanced drivetrain reliability and reduced drivetrain costs
Manufacturing Efficiency	Higher production volumes, increased automation (Cohen et al. 2008), and onsite production facilities	Enhanced economies of scale, reduced logistics costs, and increased component consistency (allowing tighter design standards and reduced weights)
O&M Strategy	Enhanced condition monitoring technology, design-specific improvements, and improved operations strategies (Wiggelinkhuizen et al. 2008)	Real-time condition monitoring of turbine operating characteristics, increased availability, and more efficient O&M maintenance planning
Power Electronics/Power Conversion	Enhanced frequency and voltage control, fault ride-through capacity, and broader operative ranges (UpWind 2011)	Improved wind farm power quality and grid service capacity, reduced power electronics costs, and improved turbine reliability
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, allowing for slimmer design margins and reduced component masses; increased plant performance
Rotor Concepts	Larger rotors with reduced turbine loads allowed by advanced controls (Malcolm and Hansen 2002) and application of light-weight advanced materials	Increased energy capture with higher reliability and less rotor mass; reduced costs in other turbine support structures
Tower Concepts	Taller towers facilitated by use of new design architectures and advanced materials (Cohen et al. 2008, LaNier 2005, and Malcolm 2004)	Reduced costs to access stronger, less turbulent winds at higher above-ground levels

As suggested by Table 1, fundamental elements of wind turbine innovations include advanced control systems to assist in shedding loads, advanced condition monitoring to minimize major component failures and unplanned turbine downtime, and forward-looking resource evaluation (i.e., seeing the wind that is approaching the turbine) in order to better position turbines to maximize production or minimize loads.

Cohen et al. (2008) estimate that taller towers could increase annual energy production by 11%. In the absence of new design innovations, however, the increased costs associated with extending towers beyond current industry norms may not be cost effective except in those sites with higher-than-average wind shear (Wiser et al. 2012). Advanced design concepts considered by Fingersh et al. (2006) suggest that higher tower heights might be achieved in the future with only incremental cost increases. 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 foundation designs (UpWind 2011, U.S. DOE 2008). Innovation opportunities include hybrid, or concrete and steel towers, application of advanced materials, and new structural designs. Ceña and Simonot (2011) estimate that a 125-m hybrid steel and concrete tower could result in a total tower materials cost reduction on the order of 40%–50%, although they expect this cost savings to be slightly less for an installed tower due to greater labor requirements associated with hybrid and concrete towers. Future tower innovations may also be targeted at easing crane height requirements, for example, with self-erecting or partially self-erecting towers, and minimizing logistics constraints, the latter of which could support reduced transportation costs.

Moving to larger rotor diameters may increase annual energy output from a given wind turbine by as much as 10%–30% (Cohen et al. 2008). To achieve larger rotor diameters without significant cost increases or efficiency losses, however, new innovations that reduce blade weight and loads are necessary (Griffin 2001). Some weight reductions may be achieved by incremental design refinements and optimizations or the application of new materials with lower mass-to-strength ratios. More significant weight reductions might be achieved with designs that passively shed loads by twisting (Ashwill 2009) or that include partial blade span actuation (i.e., the ability to control different sections of a single turbine blade) coupled with sensing capacities that allow the rotor to adapt to variability in wind conditions and turbulence in different parts of the rotor disk (Buhl et al. 2005, Lackner and van Kuik 2009, and UpWind 2011). Trailing edge flaps that react to the wind as it is moving towards the rotor rather than the wind that has already passed by could also assist in load shedding and ultimately weight reductions (Andersen et al. 2006, Berg et al. 2009).

Optimization of current drivetrain designs to increase reliability and reduce weight is expected to reduce drivetrain cost and increase performance (e.g., Peeters et al. 2006, Heege et al. 2007). However, wholly new architectures are also possible and are in development and production, including direct drive turbines, single-stage medium-speed geared designs, and multi-generator architectures (Cohen et al. 2008). Permanent magnet generators have become increasingly common in wind turbine design and may resolve some of the longstanding challenges of weight and size typically associated with direct drive machines. UpWind (2011) specifically identified permanent magnet transversal flux generators from among 10 specific drivetrain configurations to be particularly promising in terms of drivetrain weight reduction. Drivetrain advancements were estimated by Cohen et al. (2008) to result in increases in energy production up to 8% while also potentially reducing costs by as much as 11%.

Advanced manufacturing strategies are expected to result in tighter design tolerances, driving down weight and increasing product reliability as well as lowering overall turbine costs as a result of process improvements and greater economies of scale (Cohen et al. 2008, UpWind 2011). New manufacturing strategies that allow for on-site production could also be employed to lower logistics and transportation costs. Broader use of condition monitoring and increasingly refined operational strategies (e.g., use of preventive maintenance strategies and enhanced planning for turbine downtime) are expected to facilitate reductions in operations and replacement costs. Finally, improvements in power electronics may reduce costs while increasing the ability of wind turbines to provide grid services.

4.5 Quantitative Summary of Future Cost Estimates

Policy analysts, researchers, trade groups, and others have commonly utilized one or more of the approaches described above to estimate the future cost of wind energy. Cost projections applying these approaches vary, although when considered against at least the higher end of the range of historical learning rates observed in the literature and suggested for every doubling of global capacity (see Section 4.1 or Wiser et al. 2011), the range is somewhat less dramatic.[19]

Figure 11 compiles and normalizes data from 13 relatively recent analyses (including both research studies and policy analysis modeling inputs) and 18 scenarios to illustrate the expected range of the future costs for onshore wind energy anticipated in the literature. The LCOE reduction estimates shown in Figure 11 were developed by extracting data from individual studies and scenarios. Raw cost data were converted to common values (i.e., 2009 dollars), and a minimum performance starting point. From these normalized data, an estimated LCOE for each scenario was calculated. LCOE values for this portion of the analysis were estimated with the simplified LCOE methodology also employed in the IPCC Special Report on Renewable Energy Sources (Moomaw et al. 2011). Where there were incomplete data for a given scenario (e.g., only capital costs available) representative industry data were utilized for other assumptions. After calculating the annual percent reduction in LCOE implied by each scenario, scenarios were aligned to a common starting point to estimate the percentage reduction in LCOE from 2010 to 2030. Studies analyzed were dated between 2007 and 2011. Based on this relatively narrow and recent time frame, it was assumed that the drivers of specific cost reduction trajectories remain generally fully available to be integrated into the average fleet turbine (i.e., if a study was completed in 2007, the technological advancements envisioned would not be fully tapped by the

[19] Learning rates are a function of cumulative installed capacity, and it is not unreasonable to expect that global installed wind power capacity will double more than once over the next 20 years. Achieving 20% wind energy by 2030 in the United States has been estimated to require 305 gigawatts (GW), or an additional 260 GW from the end-of-year 2010 figure (DOE 2008). China expects to have perhaps 200 GW installed by 2020, roughly a 150-GW increase (GWEC 2011). Global capacity was 197 GW at year-end 2010 and thus China's activities alone could nearly double global capacity by 2020. The Global Wind Energy Council deployment forecast based on data through 2010 suggests an average 18% growth annual rate over the next 5 years, which would result in a doubling of global capacity by the end of 2014 (GWEC 2011). The higher end of the historical learning rates presented in the literature for onshore wind energy, if applied to the anticipated number of doublings of installed wind power capacity by 2020 or 2030, would, in many cases, yield cost reductions that are greater than those presented in Figure 11.

2010 starting point in Figure 11).[20] Many of these studies utilize learning curves in combination with expert elicitation, engineering models, and near-term market analysis (e.g., EWEA 2009, U.S. DOE 2008, GWEC/GPI 2010, and Lemming et al. 2009). Some of the more extreme results are generated from comparably conservative assumptions (e.g., Tidball et al. 2010) or from advanced scenarios with the most optimistic assumptions (e.g., EREC/GPI 2010, GWEC/GPI 2010, and Peter and Lehmann 2008).

The normalized data suggest an absolute range of roughly a 0%–40% reduction in LCOE through 2030 (Figure 11). The single scenario anticipating no further cost reductions assumes that the upward price pressures observed between 2004 and 2009 are moderated but remain significant enough to prevent future reductions in LCOE. The three studies anticipating a 35%–40% reduction in LCOE by 2030 represent ambitious scenarios requiring concentrated efforts to reduce the cost of wind energy and levels of investment that exceed business as usual. In addition as virtually all the studies reviewed here incorporate learning curve concepts at some level, differences in the respective scenarios also depend on the assumed levels of deployment. Nevertheless, by focusing on the results that fall between the 20th and 80th percentiles of scenarios, the range is narrowed to roughly a 20%–30% reduction in LCOE.

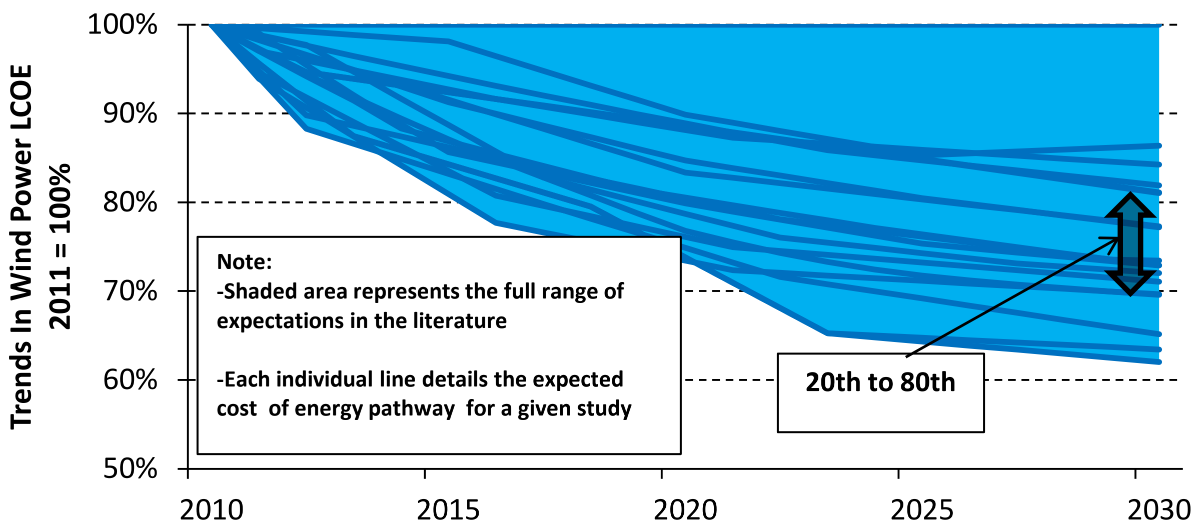

Figure 11. Estimated range of wind LCOE projections across 18 scenarios

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 2011, EPRI 2010, Peter and Lehmann 2008, GWEC/GPI 2010, IEA 2009, and European Commission 2007

LCOE reductions are generally expected to be greater in the early years and then slow over time. Initial cost reductions range from 1%–6% per year, fall to 1%–4% by 2020, and decline further

[20] 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 not in terms of cutting edge, latest technology, but rather in terms of the industry standard or average turbine among the existing fleet today, it is reasonable to assume that the LCOE represented by the existing fleet average turbine has not incorporated the vast majority of the technology improvement opportunities that are assumed to be realized in individual studies or modeling scenarios.

to 0%–1.5% by 2025. By 2030, all but one scenario envisions cost reductions falling below 1% per year.

A variety of factors are expected to influence whether or not these estimates are realized. Resurgence in turbine demand resulting in supply chain pressures similar to those observed between 2004 and 2009 could, again, drive wind energy LCOE higher. Renewed upward pressure on commodity prices that might be associated with a strong economic recovery could also drive prices higher.

At the same time, factors that may not be directly captured in the studies highlighted here, including the impact of increasing competition among manufacturers in general, could drive down costs further.

5 Conclusions

Over the past 30 years, the wind industry has become a mainstream source of electricity generation around the world. The industry has observed significant cost of energy reductions. However, from roughly 2004 to 2009, the cost of wind energy increased. Historically, cost reductions have resulted from both capital cost reductions and increased performance. From 2004 to 2009, however, continued performance increases were not enough to offset the sizable increase in capital costs that were driven by turbine upscaling, increases in materials prices, energy prices, labor costs, manufacturer profitability, and—in some markets—exchange rate movements. Nevertheless, as capital costs have moderated from their 2009–2010 levels, the cost of wind energy has fallen and is now at an all-time low within fixed wind resource classes.

Looking forward, the LCOE of wind energy is expected to continue to fall, at least on a long-term global basis and within fixed wind resource classes. Performance improvements associated with continued turbine upscaling and design advancements are anticipated, and lower capital costs may also be achievable. The magnitude of future cost reductions, however, remains highly uncertain, although most recent estimates project that the LCOE of onshore wind could fall by 20%–30% over the next two decades.

As the industry continues to mature and future technology advancement opportunities become increasingly incremental, however, LCOE reductions can be anticipated to slow. Moreover, continued movement towards lower wind speed sites may invariably increase industry-wide LCOE, despite technological improvements that would otherwise yield a lower LCOE. Other local factors such as transmission needs may also push towards higher costs. With these factors in mind, it is of important to consider the interdependence of capital costs and performance, and to evaluate the future cost of wind energy on an LCOE basis. Moreover, such evaluations must consider trends in the quality of the wind resource in which projects are located, as well as development, transmission, integration, and other cost elements that may also change (and increase) with time and deployment levels, but are sometimes ignored in traditional LCOE analyses (e.g., Dinica 2011).

Estimates of the future cost of wind energy conducted to date have often been the result of an iterative process that incorporates some combination of historical trends, learning curve analysis, expert elicitation, and engineering modeling. Theoretically, each of these approaches could independently provide an estimate of the future cost of energy; however, it has often been recognized that it is a combination of these different methodologies that is likely to yield the most accurate results. The individual strengths and weaknesses of each approach are in some ways complementary, so future projections are also expected to employ various combinations of these methods.

Further improving our understanding of possible future cost trends will require additional data gathering and improved modeling capability. Robust data collection is needed across the array of variables that must be factored into estimating LCOE (e.g., capital cost, capacity factor, O&M costs, component replacement rates and costs, and financing costs) and in each of the wind energy markets around the globe. Also needed are data on the many contextual factors that impact the overall cost of wind energy and that may also vary with time, such as interconnection costs, permitting costs, and the average wind speed of installed wind projects. Such data would allow historical LCOE trends to be more closely analyzed, with insights gleaned both through more-sophisticated learning curve analysis as well as bottom-up assessments of historical cost drivers. Additional data could also assist in better distinguishing those cost reductions that result from technological improvements from those changes in cost that result from external supply and demand market variables or changes in raw material and commodity prices. It is only with this improved historical understanding that future possible cost trajectories can be fully understood (Dinica 2011). An enhanced capacity to model the cost and performance impacts of new technological innovation opportunities, taking into account the full system dynamics that result from a given technological advancement, is also essential. Component, turbine, and project-level design and cost tools of this nature would allow for more sophisticated cost modeling and provide greater insights into possible future costs based on changes in material use and design architectures. Together these efforts would enhance our ability to understand future costs, facilitate prioritization of R&D efforts, and help to understand the role and required magnitude of deployment incentives into the future.

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Wiser, R.; Yang, Z.; Hand, M.; Hohmeyer, O.; Infield, D.; Jensen, P.H.; Nikolaev, V.; O'Malley, M.; Sinden, G.; Zervos, A. (2011). *Wind Energy. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation* [O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds)]. Cambridge, UK and New York, NY, USA: Cambridge University Press.

Appendix A

Data Inputs for U.S. and Denmark Levelized Cost of Energy Modeling

Modeling inputs from the independent U.S. and Danish levelized cost of energy (LCOE) analyses are shown in Table 1A and Table 2A, respectively. In both cases, assumptions are intended to represent industry-wide average estimates; actual performance, capital costs, operating costs, and other terms may vary widely from one project to the next. All dollar values are in real 2010 U.S. dollars, and each scenario assumes a 20-year project or economic life. For the U.S. analysis, performance is modeled and based on a 50 meter (m) annual average wind speed. As such, the U.S. analysis applied a Weibul k Factor of 2 across all scenarios and utilized the 1/7th power law to estimate hub height wind speeds, again across all scenarios. U.S. aggregate income taxes are assumed to be 38.9%. In Denmark, modeling relies on estimates of the typical full load hours for a wind regime in Eastern Denmark as acquired from industry data and sources. A Weibul k factor of 2 is assumed in the Danish analysis, and Danish corporate taxes are 25%.

Table 1A. Inputs in Modeling of U.S. LCOE Estimates 2002–2003 through 2012–2013

Characteristics	2002–2003	2009–2010	Current Turbine Pricing: ~2012–2013		
Nameplate capacity	1.5 megawatts (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/kilowatt (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%

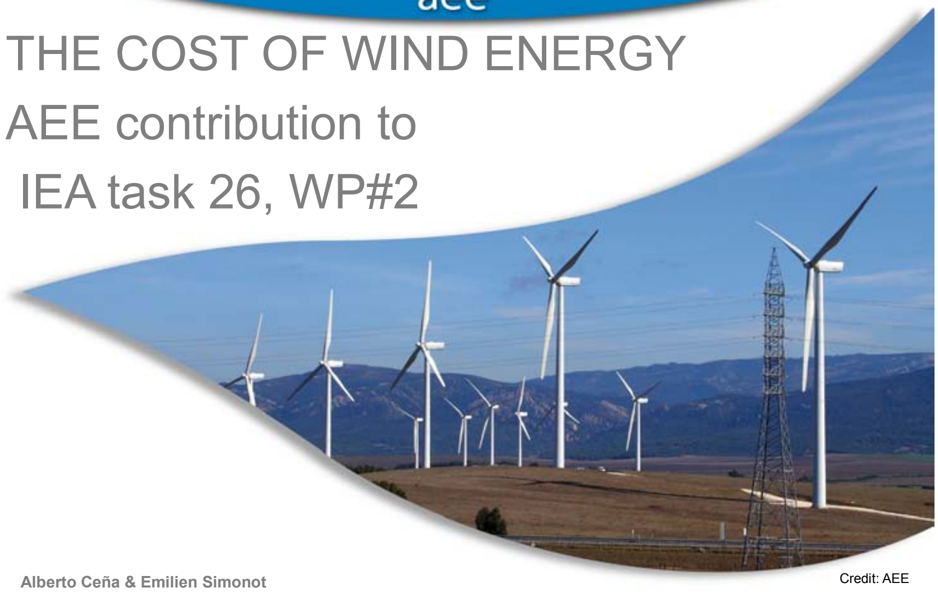
Table 2A. Inputs in Modeling of Danish LCOE Estimates 2002 through 2012

Characteristics	2002	2009	2012
Nameplate capacity	0.9 MW	2.3 MW	3.0 MW
Hub height	49 m	80 m	80 m
Rotor diameter	52 m	93 m	112 m
Installed capital cost	$1,465/kW	$1,908/kW	$1,857/kW
Operating costs	$16/megawatt-hour (MWh)	$16/MWh	$16/MWh
Full Load Hours	2209	3102	3602
Financing cost/ discount rate (nominal)	8%	8%	8%

Appendix B. The Cost of Wind Energy Presentations

The Cost of Wind Energy

THE COST OF WIND ENERGY
AEE contribution to
IEA task 26, WP#2



Credit: AEE

Alberto Ceña & Emilien Simonot
esimonot@aeeolica.org
Technical department
Spanish Wind Energy Association

July 2011

OBJECTIVES OF THE STUDY

- Identify the factors influencing the evolution of wind turbine generator (WTG) design and technical characteristics
- Understand the influence of design evolution and external factors on the cost of WTG
- Highlight critical issues that could influence the cost of WTG in the near future.

APPROACH OF THE STUDY

- Study challenges:
  - Assess how WTG costs vary over time
  - Determine the factors that influence WTG cost variations, including:
    - Needed technology changes (e.g., size and weight increase, and new technology standards)
    - External factors (e.g., raw material costs, energy, and manpower)

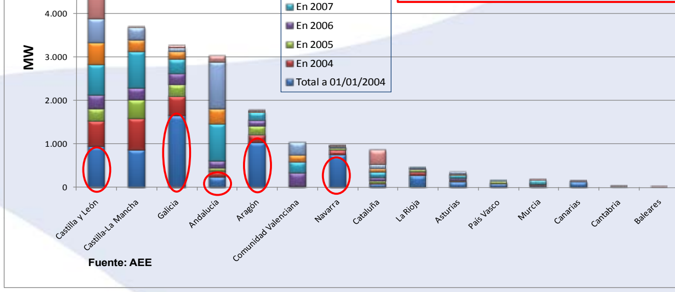
  → Try to identify the effect of each factor
- Data inputs:
  - All sources available, including AEE´s statistics, WTG manufacturers´ portfolios, and theses
- Study criteria:
  - WTG broken down into three main types studied separately: Rotor, Nacelle, and Tower.

3

WIND ENERGY DEPLOYMENT IN SPAIN

HISTORICAL AND GEOGRAPHIC TRENDS

Most of the best spots occupied during the early development of wind energy were in place before 2004.

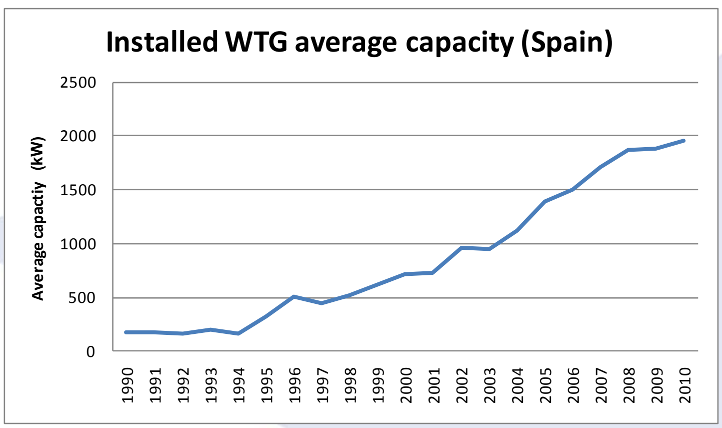


Autonomous community	Accumulated capacity end 2010 (megawatts [MW])
Castilla y León	4803,815
Castilla-La Mancha	3709,19
Galicia	3289,325
Andalucía	2979,33
Aragón	1764,01
Comunidad Valenciana	986,99
Navarra	968,37
Cataluña	851,41
La Rioja	446,62
Asturias	355,95
País Vasco	153,25
Murcia	189,91
Canarias	138,92
Cantabria	35,3
Baleares	3,65

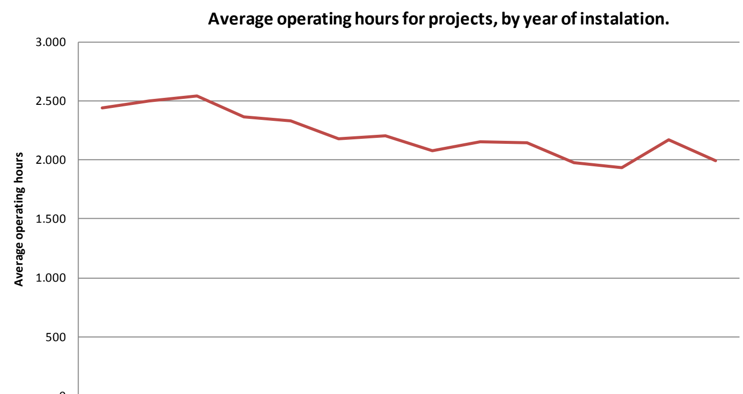
Today, leading regions (in terms of installed capacity) are not the best wind resource regions. As such:

- Developers have to deal with medium and low wind conditions
- There is a need to adapt technology to these sites.

TREND IS TO INSTALL BIGGER AND BIGGER WTG



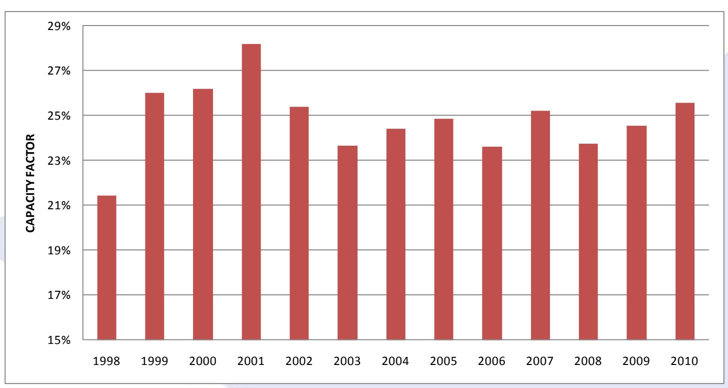
THE OPERATING HOURS OF WIND FARMS DECREASED SLOWLY DURING THE LAST DECADE—FROM 2,500 TO 2,000 HOURS AND STABILIZED AROUND 2,000 HOURS



	Ant-98	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Year of instalation	2.440	2.496	2.544	2.366	2.328	2.181	2.201	2.077	2.148	2.147	1.973	1.931	2.170	1.993

Source: CNE

GLOBAL CAPACITY FACTOR EVOLUTION



Early development of wind power: best wind condition sites → Worse wind conditions → Worse wind conditions but technology adaptation

The current average capacity factor is lower than in early 2000 and is oscillating from 23% to 25%.

FACTORS INFLUENCING WIND POWER COSTS

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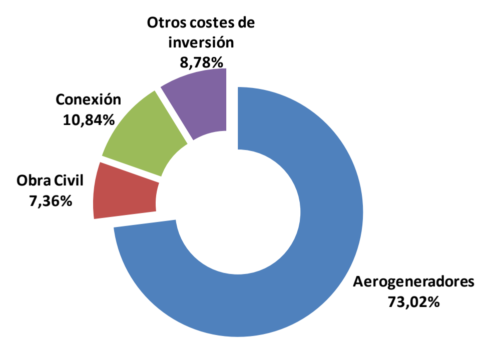
WTG AND WIND FARM COSTS



Fuente: Estudio INTERMONEY y AEE

Onshore wind farm investment costs are closely linked to WTG costs which represent 73% of the total investment costs.

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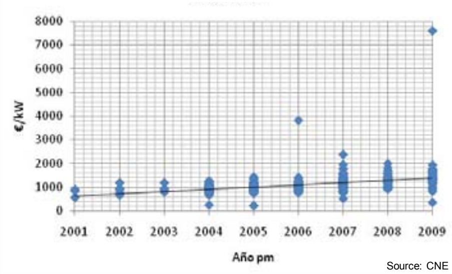
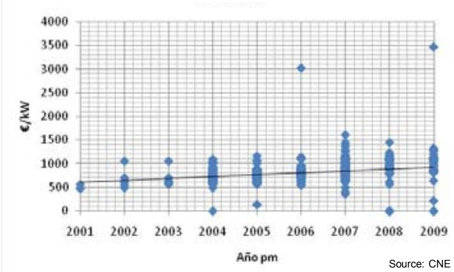
WTG AND WIND FARM COSTS—NO APPLICATION OF THE LEARNING CURVE

Wind farms costs 2001-2009



Wind turbines costs 2001-2009



Average installed project costs have increased 100% in the period 2001-2009.	Average WTG costs have increased 50% in the period 2001-2009.
Before 2006: investment costs increase and standard deviation remains low. ***Low cost period.***	Before 2004: demand meets offer. From 2004 to 2006: high demand and strong cost increases.
2007: 3,520 MW installed. The high demand pushes costs up. Wide range of costs. ***Transition period.***	2007: Wide range of costs due to very high demand. The variation of raw material costs starts.
Since 2008: Stabilization of costs at higher levels. The standard deviation decreases but the average costs remain high. ***High cost period.***	Since 2008: Costs remain high as the result of: - Lower demand due to the end of the regulatory framework - Increase of raw material prices (i.e., steel, copper, and fiberglass)

Future trends: - Prices may decrease as a result of more offers at lower prices (new manufacturers especially from Asia)
- Technology evolution and costs of material have to be taken into account.

LEARNING CURVE AND FUTURE TRENDS

In Spain, it appears that no learning curve exists, from the early industrial stage of wind power to the present, no cost reductions have been observed.

- Reduction of production costs must have happened—but were hidden by a high demand market—which is not an appropriate scenario to incentivize cost reduction.
- Recent changes introduce new industry challenges and costs:
  - The regulatory framework: needs for local production in the new regional tenders mean a rise in investment costs
  - Less and less good wind condition sites: bigger diameter and higher towers
  - Market volatility and supply insecurity for raw materials (i.e., steel, copper, and rare earth metals)
  - Decrease of Spanish market installation rhythm means WTG manufacturer strategy to look abroad → new investments.

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COST OF MATERIALS

WEIGHT AND RAW MATERIAL INFLUENCE ON WTG COST VARIATION

Formula used to determine how weight increase and raw material costs independently influence WTG cost:

Determination of **influence of weight increase *W*** for each material between year *n-x* and year *n*:

$$W = \frac{\left(Weight_n - Weight_{n-x}\right) \times Cost_{n-x}}{\left(Cost_n \times Weight_n\right) - \left(Cost_{n-x} \times Weight_{n-x}\right)}$$

Determination of **influence of raw material cost variation *C*** for each material between year *n-x* and year *n*:

$$C = \frac{\left(Cost_n - Cost_{n-x}\right) \times Weight_n}{\left(Cost_n \times Weight_n\right) - \left(Cost_{n-x} \times Weight_{n-x}\right)}$$

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RAW MATERIALS COSTS

MATERIAL	2006 PRICE	CURRENT PRICE
Iron (Cast Steel) (1)	370 €/t	500 €/t
Steel (2)	460 €/t	620 €/t
Copper	~ 5.500 \$/t = ~ 4.500€/t (2)	~ 9.000 \$/t = ~ 7.000 €/t (3)
Glass fiber	~	~ 450 €/t (4)
Resin	Unknown composition	

Values to be considered in the next slides.

(1) Iron price: 80% of steel price
(2) Flat Products/HRC/S. Europe domestic Ex-Works €/t
(3) IMF Commodity Price Survey
(4) Personal communication

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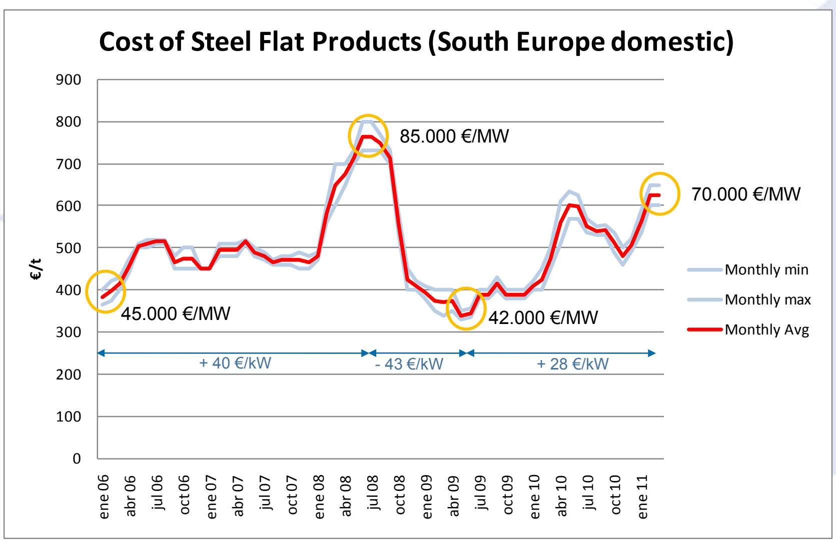
STEEL COST EVOLUTION SINCE 2006



Flat Products/HRC/S. Europe domestic Ex-Works €/t

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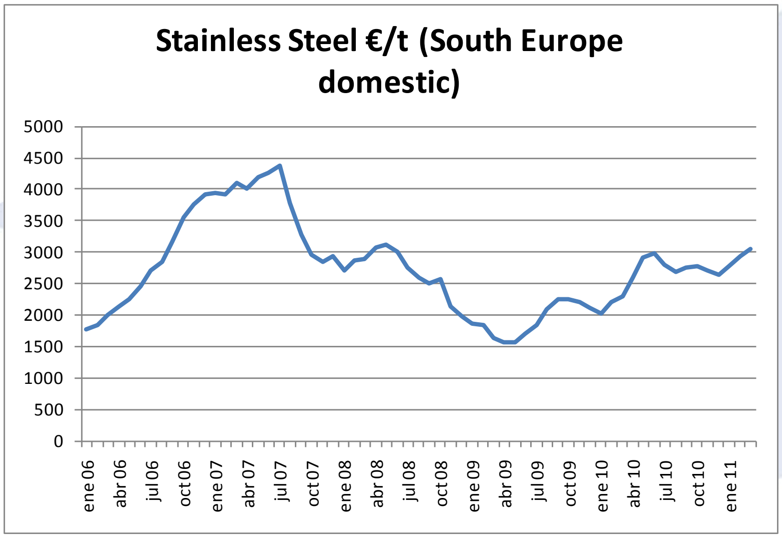
STAINLESS STEEL COST EVOLUTION SINCE 2006



Stainless Steel/CR 304 2B 2mm coil transaction/S. Europe domestic delivered €/t

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1- NACELLE

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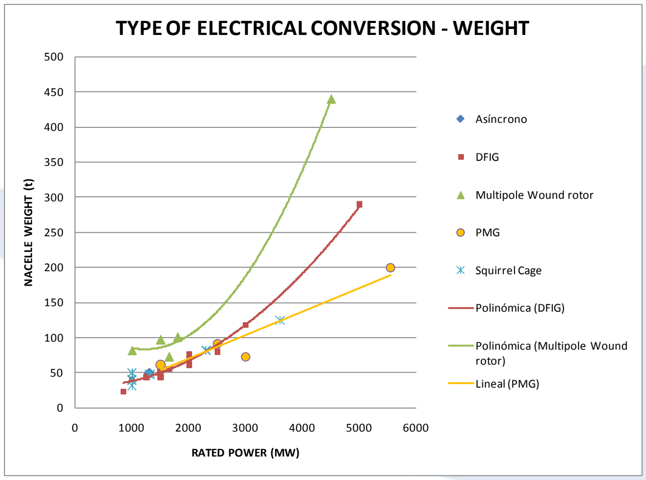
NACELLE WEIGHT: INFLUENCE OF ELECTRICAL CONVERSION TECHNOLOGY



Typology with permanent magnet generator could be the lightest one, whereas multipole wound generator technology is the heaviest one.

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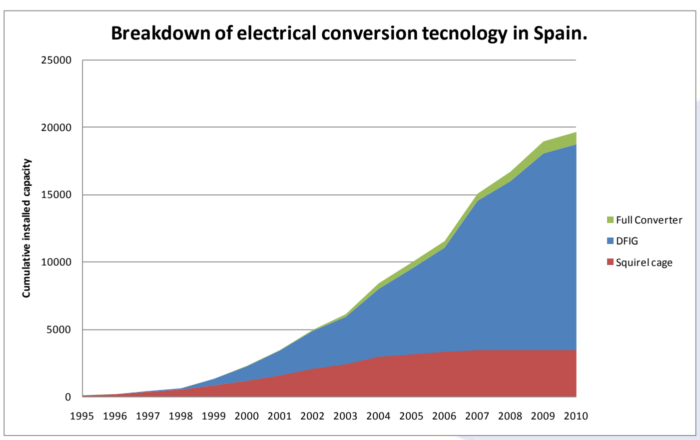
EVOLVING GRID CODES WILL ENCOURAGE THE USE OF NEW CONVERSION SYSTEMS



For installed WTG, retrofits are needed to comply with new grid codes. As a result, unplanned costs can arise during the operation phase.

Due to new grid codes requirements, the technological trend is to use full converter in new WTG designs.

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ISSUES: GENERATORS AND POWER ELECTRONICS

- Trends to build WTG equipped with permanent magnet generators or multipole technology include:
  - No gearbox = may reduce operation and maintenance (O&M) costs
  - Full converter = easier grid integration but higher cost
  - Larger generators = heavier
- Permanent magnet generators – use of rare earth:
  - Demand of rare earth is high because of lots of other applications
  - China generates 97% of world production and risks exist regarding future delivery.

Symbol	Name	Selected Usages
Pr	Praseodymium	**Rare-earth magnets**, lasers, core material for carbon arc lighting, colourant in glasses and enamels, additive in Didymium glass used in welding goggles, ferrocerium firesteel (flint) products
Nd	Neodymium	**Rare-earth magnets**, lasers, violet colors in glass and ceramics, ceramic capacitors
Sm	Samarium	**Rare-earth magnets**, lasers, neutron capture, masers
Gd	Gadolinium	**Rare-earth magnets**, high refractive index glass or garnets, lasers, x-ray tubes, computer memories, neutron capture
Dy	Dysprosium	**Rare-earth magnets**, lasers

Rare earth used in the construction of permanent magnets.

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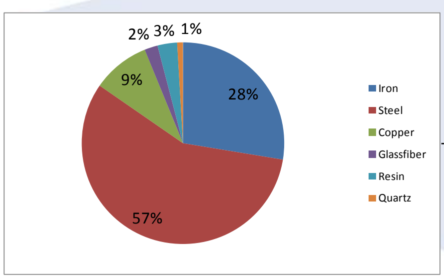
ISSUES RELATED TO NACELLE MATERIALS

- The weight of nacelle rises from 30 tons in 1 MW WTG up to more than 120 tons in multi MW WTG

  Need to consider specific logistic solutions: higher load trucks and heavier lifting capacities
- Nacelle raw material structure:



WTG nacelle raw material breakdown (GAMESA G8X)

Raw material	Tons
Iron	10, 5
Steel	21, 69
Copper	3, 5
Glass fiber	0, 8
Resin	1, 2
Quartz	0, 35

Gamesa G8X Nacelle (real data)

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Source: Life cycle assessment of a multi-megawatt wind turbine - E. Martínez, F. Sanz - Renewable Energy 34 (2009) 667–673

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EVOLUTION OF COST OF MATERIALS IN NACELLE

Use of raw material in WTG nacelle						
Period	2004 – 2010		Present and Future			
WTG type	2 MW – doubly fed induction generator (DFIG)	Cost	Estimation for a 3 MW– DFIG or similar	Cost	Variation	
					Due to raw material cost changes	Due to WTG weight increase
Iron (cast steel)	~10.5 ton	3.885 €	~33 tons	16.500 €	34%	66%
Steel	~22 ton	10.120 €	~68 ton	42.160 €	34%	66%
Copper	~3.5 ton	15.750 €	~10 ton	70 000 €	46%	54%
Glass fiber	~0.8 ton		~2.3 ton	1100 €	No historical data available	
Resin	~1.2 ton		~3.5 ton		Unknown composition	
Quartz	~0.3 ton		~1.2 ton		No data available	

The cost increase of raw material in WTG nacelles from **steel**:

- **Approximately 1/3**, from the **cost increase of raw material**.
- **Approximately 2/3**, to the **size and weight increase of the WTG**.

For **copper**, these **two factors each share 50% of the variation**.

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2- BLADES

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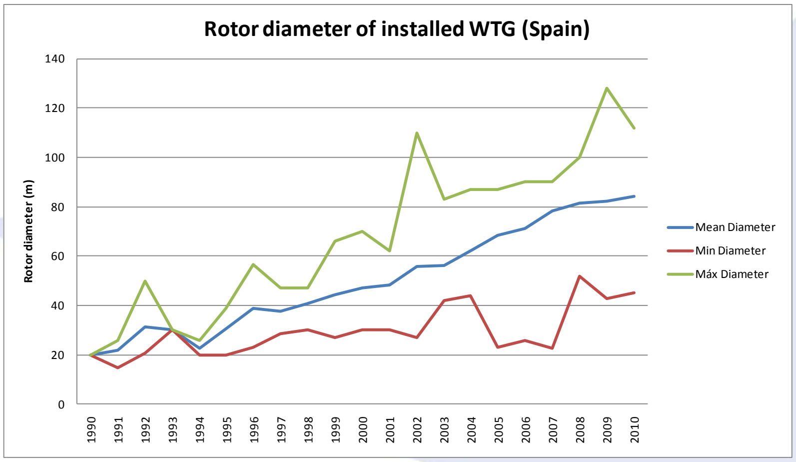
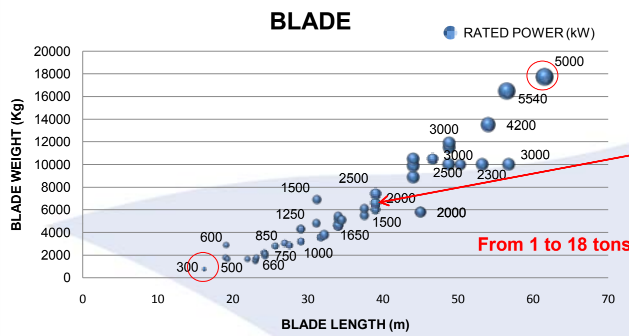
ROTOR SIZE: BIGGER AND BIGGER



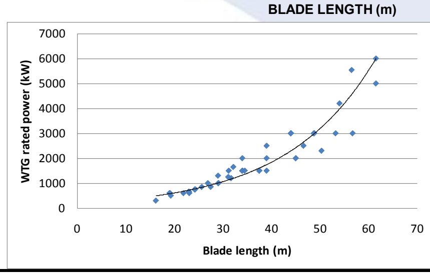
- The increase of diameter has been constant since the earliest stages of wind power development.
- Latest WTG designs with rotor diameter of more than 100 meters (m) show that this tendency should continue.

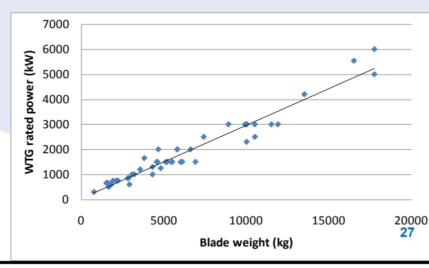
BLADES ARE ALSO GETTING HEAVIER AND HEAVIER



G8X (~40m) Blade material breakdown	
Resin	3.9 tons
Fiberglass	2.6 tons
Total	**6.5 tons**

Continuous growth is observed, however, length seems to grow quicker than weight.





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ISSUES RELATED TO BLADE MATERIALS

- Wind turbine blades are made of a main frame and several different layers:
  - Frame and internal layers are designed to be as light as possible
  - External layers responsible for protection and wind harnessing are composed of glass fiber and resins
  - Chinese fiberglass is gaining market share due to a low price policy.

- Technological trends:
  - Segmented blades, optimized logistics
  - New materials, including use of carbon fiber, resins improvement, and special coatings (e.g., anti biofouling and stealth)

- WTG blades have not experienced very important changes in their structural designs since the 90´s. The possibility to reach a maximum length/weight ratio has to be considered and R&D efforts are planned to address this issue (including research on new materials and designs).

EVOLUTION OF COST OF MATERIAL FOR BLADES

Use of raw material in WTG blades						
Period	2004 – 2010		Present and Future			
Blade type	40 m long/ 7, 5 ton	Cost	60 m long/ 17, 7 ton	Cost	Variation	
					Due to raw material cost changes	Due to WTG weight increase
Glass fiber	~ 2.6 ton	No historical data available	~6.2 ton	2790 €	No historical data available	
Resin	~1.2 ton		~3.5 ton		Unknown Composition	

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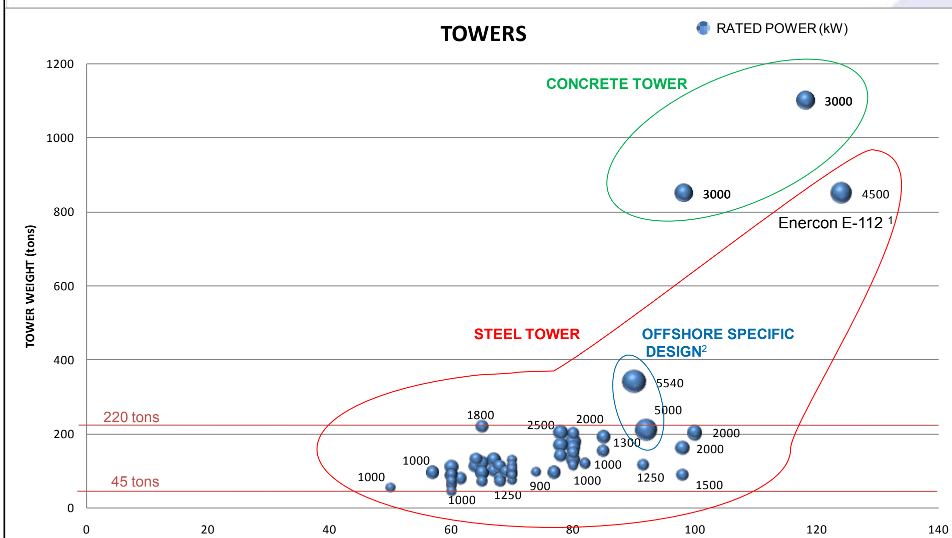
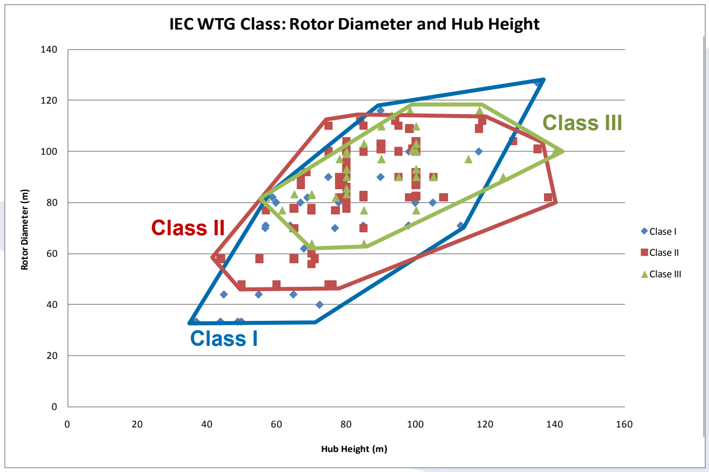
3-TOWERS

WEIGHT INCREASE IN WTG TOWERS



(1) http://www.enercon.de/en-en/633.htm for E-112 reference
(2) Lower hub heights

CORRELATION BETWEEN DIAMETER/TOWER HEIGHT AND WTG IEC CLASS



(Difficult interpretation: WTG Class I/II and WTG Class II/III mixed)

Higher class (lower wind speeds) means larger rotor diameters and higher towers.

EVOLUTION OF COST OF MATERIAL FOR TOWERS

	Use of raw material in towers						
	Period	2006		2010			
	WTG type	•2 MW – DFIG •Hub height: 80 m (steel tower)	Cost	•Estimation for a 3 MW– DFIG or similar •Hub Height: 125 m (steel or hybrid tower)	Cost	Variation: Due to raw material cost changes	Variation: Due to WTG weight increase
STEEL TOWER	**Steel**	~ 180 ton	82.800 €	~ 425 ton	~ 263.000 €	+ 38%	+ 62%
HYBRID TOWER	**Steel**	-		162 ton (including steel segment and steel reinforcement in the concrete segment)	100.400 €	- 62% (compared to full steel structure)	
HYBRID TOWER	**Concrete**	-		740 ton	46 000 €		
HYBRID TOWER				Total Hybrid Design	146.400 €	- 44% (compared to full steel structure)	

The cost increase of raw material in WTG towers from **steel**:

- **Approximately 1/3**, to the **cost increment of raw material**
- **Approximately 2/3**, to the **size and weight increment of the WTG**.

When using hybrid designs, the raw material cost reduction resulting from the use of concrete is important, however, it must also consider an increase in manpower costs (not counted here).

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SUMMARY

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Summary: Use of raw material in WTG

	Period	2006		2010			
	WTG type	•2 MW – DFIG •Blade 40 m long/ 7, 5 ton •Hub height: 80 m (steel tower)	Cost	•Estimation for a 3 MW– DFIG or similar •Blade: 60 m long/ 17, 7 ton •Hub Height: 125 m (steel or hybrid tower)	Cost	Variation Due to raw material cost changes	Variation Due to WTG weight increase
NACELLE	**Iron (Steel Casts)**	~10.5 ton	3.885 €	~33 tons	16.500 €	+ 34%	+ 66%
NACELLE	**Steel**	~22 ton	10.120 €	~68 ton	42.160 €	+ 34%	+ 66%
NACELLE	**Copper**	~3.5 ton	15.750 €	~10 ton	70 000 €	+ 46%	+ 54%
NACELLE	**Glass fiber**	~0.8 ton	No historical data available	~2.3 ton	1100 €	No historical data available	
NACELLE	**Resin**	~1.2 ton		~3.5 ton		Unknown composition	
BLADE	**Glass fiber**	~ 2.6 ton	No historical data available	~6.2 ton	2790 €	No historical data available	
BLADE	**Resin**	~1.2 ton		~3.5 ton		Unknown composition	
STEEL TOWER	**Steel**	~ 180 ton	82.800 €	~ 425 ton	~ 263.000 €	+ 38%	+ 62%
HYBRID TOWER[1]	**Steel**	-		162 ton	100.400 €	- 62% (compared to full steel structure)	
HYBRID TOWER[1]	**Concrete**	-		740 ton	46 000 €		
				Total Hybrid Design	146.400 €	- 44% (compared to full steel structure)	

(1) Data for hybrid tower extracted from tall tower for large wind turbines, report from Vindfork project V-324 Höga torn för vindkraftverk – Elforsk rapport 10:48

THANK YOU FOR YOUR ATTENTION

Credit: AEE

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Spanish Wind Energy Association

Danish Wind Project Performance, Capital Cost, and Price Trends

IEA Wind Task 26: Cost of Wind Power

Edward James-Smith

Golden, March 29, 2011

Ea Energy Analyses

Explanatory Notes

- Price data is from actual projects in Denmark and is published in the report *Vindmøllers Økonomi, February 2010*
- Updates for 2010 from projects and turbine manufacturer
- Data for 2004 to 2007 is from a very small pool of turbines due to the low deployment in Denmark during this period
- Production data is from the Danish Energy Agency wind turbine register
- Wind data is from the Danish Wind Turbine Owners' Association
- Performance data from 2004 is high as most turbines erected that year were demonstration turbines with large rotors and high hubs.

2

Ea Energy Analyses

PRICE TRENDS IN DENMARK

3

Ea Energy Analyses

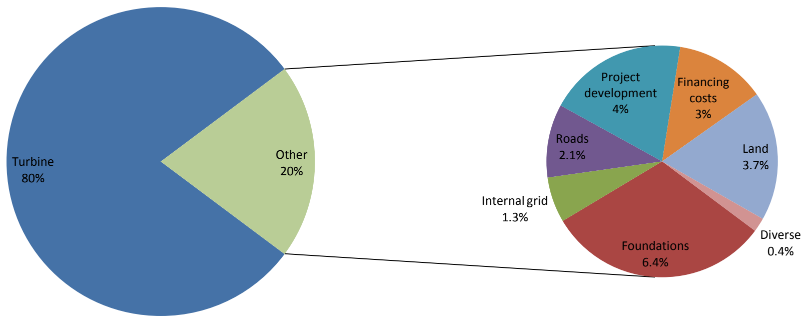
General Trends in Denmark - Price

- Capital costs have fallen sharply since 2008
- Some turbines have been available at lower prices due to orders being cancelled or defaulted – can mask true price of turbines
- Overcapacity in manufacturing – downward pressure
- Turbines are getting higher and rotor diameters larger
- Manufacturing base is moving away from Denmark.

4

Ea Energy Analyses

Breakdown of costs



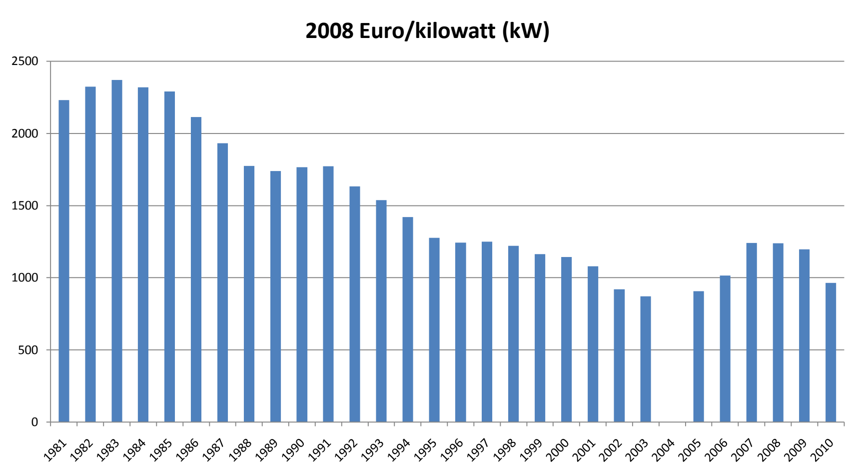
Data from *Vindmøllers Økonomi (2010)*

On average, wind projects spend 9% of the total budget on purchasing old turbines for repowering. These costs are considered to be covered by the repowering subsidy and are therefore not included.

5

Ea Energy Analyses

Turbine Prices in Denmark

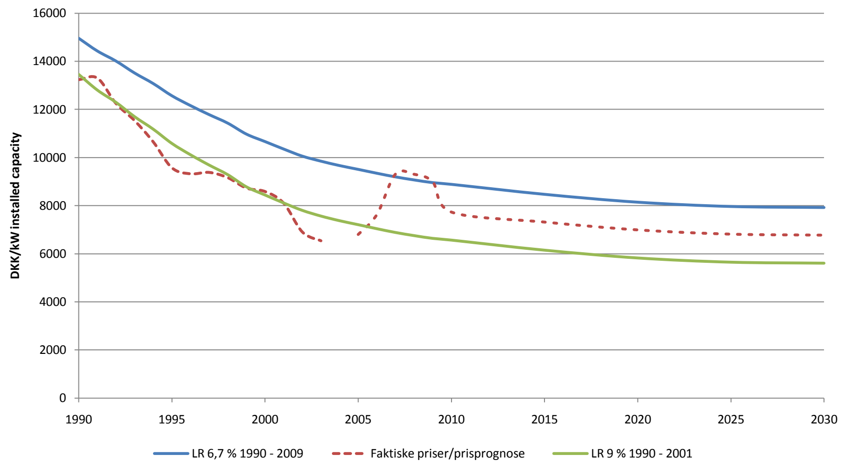


Data From: Vindmøllers Økonomi (2010)

6

Ea Energy Analyses

Learning Rates and Prices



Source: Vindmøllers Økonomi (2010)

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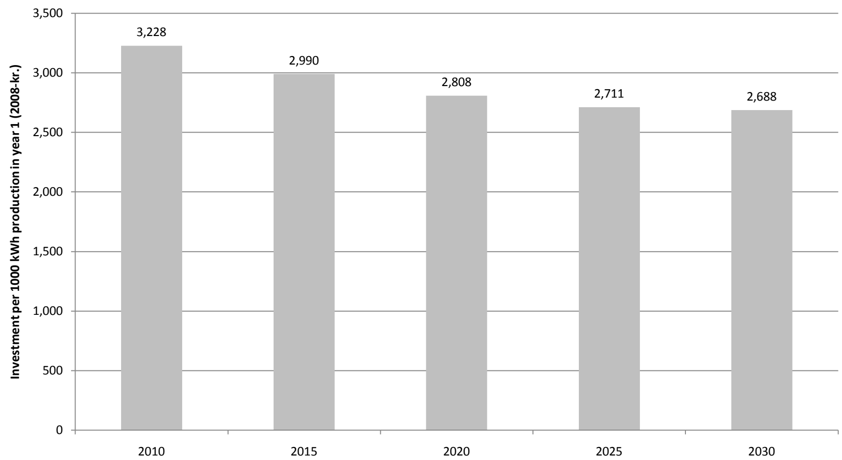
Prices in the European Union Using European Wind Energy Association Targets and Learning Rates

Source: Vindmøllers Økonomi (2010)

8

Price Prognosis: Total Investment (Danish Krone per Megawatt-hour [MWh]) in Year One – Equivalent of One Share in Danish Turbine Cooperative



Source: Vindmøllers Økonomi (2010)

9

Ea Energy Analyses

PERFORMANCE OF DANISH TURBINES

10

Ea Energy Analyses

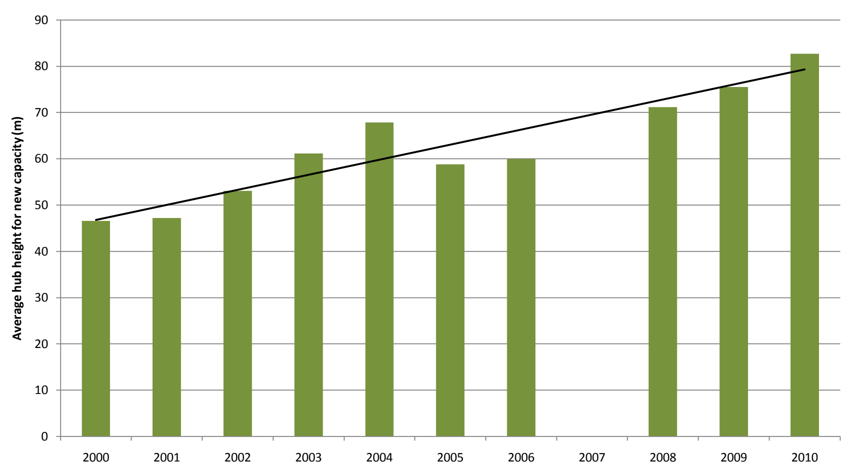
General Trends in Performance

- Turbines have higher hub heights and larger rotors
- Resulted in marked increase in capacity factor since 2000 – average capacity factor for onshore turbines has increased by ~ 50%
- The increase in capacity factor appears to have resulted in lower prices per kilowatt-hour (kWh).

11

Ea Energy Analyses

Hub Heights

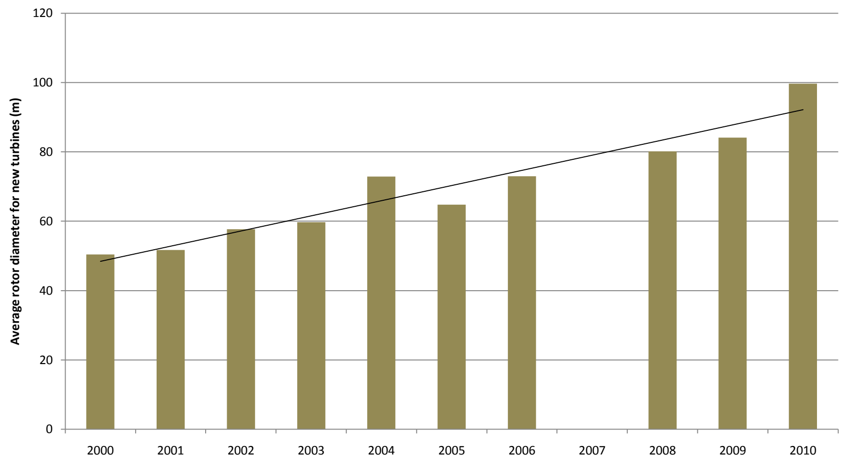


Source: Vindmøllers Økonomi (2010)

12

Ea Energy Analyses

Rotor Diameters



Source: Vindmøllers Økonomi (2010)

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Ea Energy Analyses

Annual Wind Energy in Denmark

	Jan.	Feb.	Mar.	Apr.	Maj.	Jun.	Jul.	Aug.	Sep.	Okt.	Nov.	Dec.	Gns.
2005	193	112	97	84	72	76	53	74	65	71	100	121	93,2
2006	81	62	86	85	100	54	32	43	83	84	146	168	85,2
2007	224	117	129	103	72	51	96	79	126	56	122	104	106,5
2008	192	159	140	49	40	95	60	82	61	120	133	72	100,2
2009	104	72	96	56	94	85	66	75	98	101	133	75	87,9
2010	102	68	88	88	85	60	51	69	**97**				**78,6**

Source: Danish Energy Agency Wind Turbine Register

Production data from January 1 to September 30, 2010 was used for all onshore wind turbines commissioned from 2000 to September 2010 and adjusted to normal wind year to determine average performance per commissioning year.

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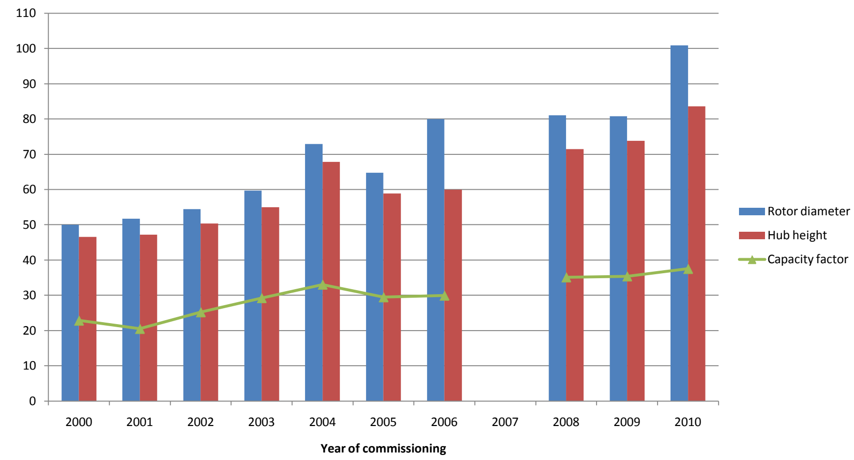
Ea Energy Analyses

Performance of Danish Onshore Turbines From January to September 2010 (Adjusted to Normal Wind Year)



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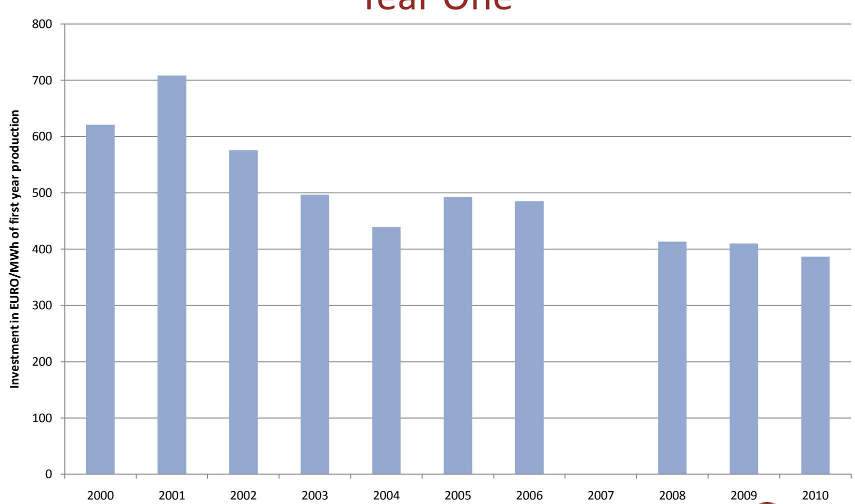
Ea Energy Analyses

Price Equivalent of One Share in Danish Turbine Cooperative, Total Investment Euro/MWh in Year One



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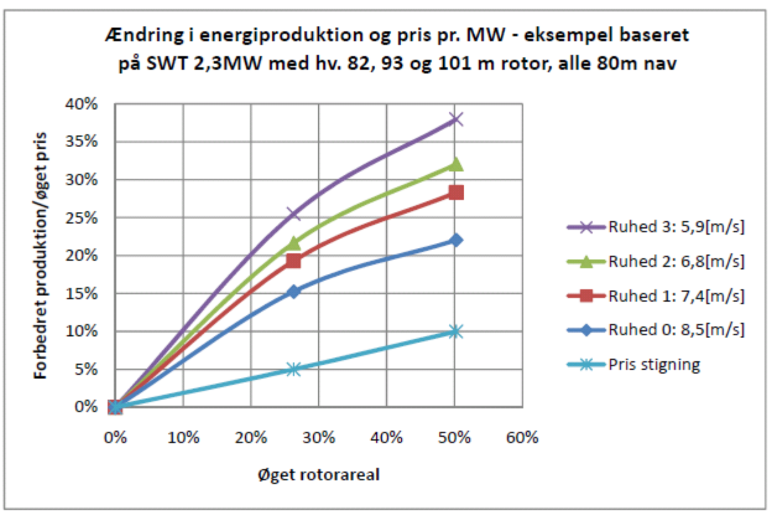
Ea Energy Analyses

ADDITIONAL SLIDES ON COSTS AND PRODUCTION

17

Ea Energy Analyses

Change in Energy Production and Price Per Megawatt for SWT 2.3 MW with 82, 93, and 101 Meters at Different Wind Speeds



Source: Vindmøllers Økonomi (2010)

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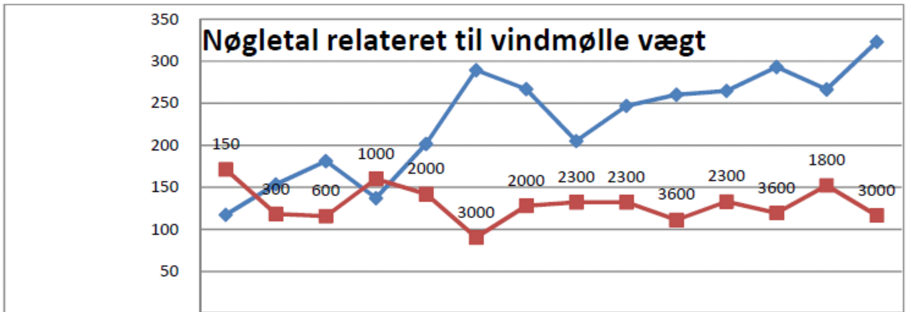
Ea Energy Analyses

Production in Relation to Weight



	1988	1992	1996	2000	2004	2006	2008	2008	2009	2009	2009	2009	2010	2010
MWh/10år/Ton	117	154	181	137	202	289	267	205	247	260	265	293	267	323
Ton/MW	171	118	116	160	142	90	128	132	132	111	133	119	152	117

Source: Vindmøllers Økonomi (2010)

19 Ea Energy Analyses

Cost of Steel

	Gns. stålpris kr/ton	Vindmøllepris kr/kW	Omkostninger til stål kr/kW	Omkostninger til stål i pct. af vindmølleprisen
2003	3.228 kr.	5.544 kr.	369 kr.	6,7 %
2004	4.255 kr.	-	486 kr.	-
2005	5.610 kr.	5.776 kr.	641 kr.	11,1 %
2006	5.285 kr.	6.478 kr.	604 kr.	9,3 %
2007	5.832 kr.	7.910 kr.	666 kr.	8,4 %
2008	6.503 kr.	7.905 kr.	743 kr.	9,4 %
2009	4.344 kr.	7.679 kr.	496 kr.	6,5 %

Source: Vindmøllers Økonomi (2010)

20 Ea Energy Analyses

Labor Costs

År	Antal medar-bejdere	MW solgt	kW/med-arbejder	Lønninger (Mio. kr.)	Lønninger (kr./kW)	Lønstigning/ kW fra år til år	Løn pct. Af omkostninger /kW
2003	6.394	2.667	417	2.355	883	-	16 %
2004	9.449	2.784	295	3.232	1.161	278	-
2005	10.300	3.900	379	3.749	961	-200	17 %
2006	11.334	4.313	381	4.350	1.009	47	16 %
2007	13.820	4.974	360	5.200	1.046	37	13 %
2008	17.924	6.160	344	6.785	1.102	91	14 %

Source: Vindmøllers Økonomi (2010)

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Ea Energy Analyses

Summary of Costs

	Stigning i DKK fra 2003 til 2008
Stål	370kr/kW
Lønomkostninger	219kr/kW
EBIT	579kr/kW
Større rotorer/tårne	274kr/kW
Andre råstoffer	100kr/kW
Kvantificerede prisstigninger	**1.542kr/kW**
Total prisstigning for vindmøller	**2.350kr/kW**
Ikke kvantificerede prisstigninger	808kr/kW

Source: Vindmøllers Økonomi (2010)

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Ea Energy Analyses

Development of LCOE for Wind Turbines in Denmark

Development in LCOE for Wind Turbines in Denmark

Edward James-Smith

Ea Energy Analyses

Methodology

- Input
  - Power curves for typical turbines built in 2002 and 2009 and an example of a high-performance turbine available for delivery in 2012
  - Capacity factor calculated for turbines at average wind speeds of 7.5 meters (m) per second (s), 7.2 m/s, 6.9 m/s, and 5.9 m/s and Weibull shape parameter of 2.3
  - Cost data from IEA Wind Task 26 and turbine manufacturer
  - Historical generation data for 2002 and 2009 turbines and first year generation data for two turbines of type available for delivery in 2012
  - Historical data used to validate calculated data.
- Output
  - Levelized cost of energy (LCOE) determined in 2008 Euro using IEA Wind Task 26 LCOE calculator
  - Comparison of relative price and relative value in Denmark using current subsidy program.

2

Ea Energy Analyses

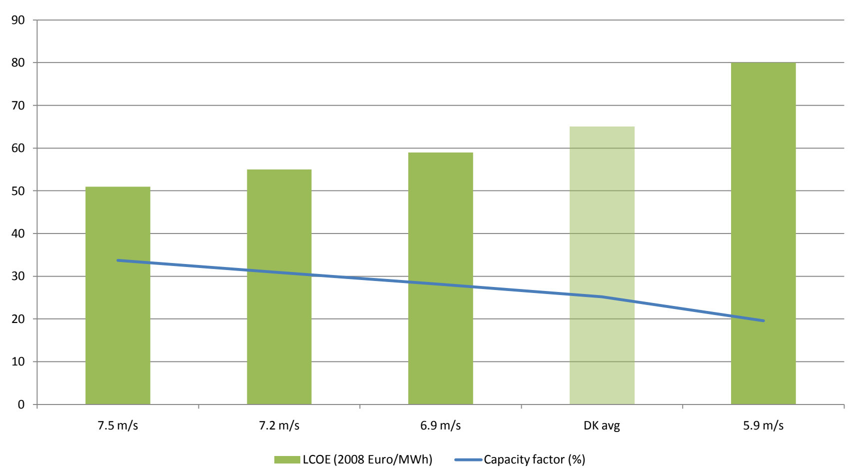
Capacity Factor for Turbines

	2002	2009	2012
7.5 m/s	34%	37%	48%
7.2 m/s	31%	34%	45%
6.9 m/s	28%	32%	43%
5.9 m/s	20%	24%	33%
Actual Danish Average	25%	35%	41%

3

Ea Energy Analyses

LCOE 2002



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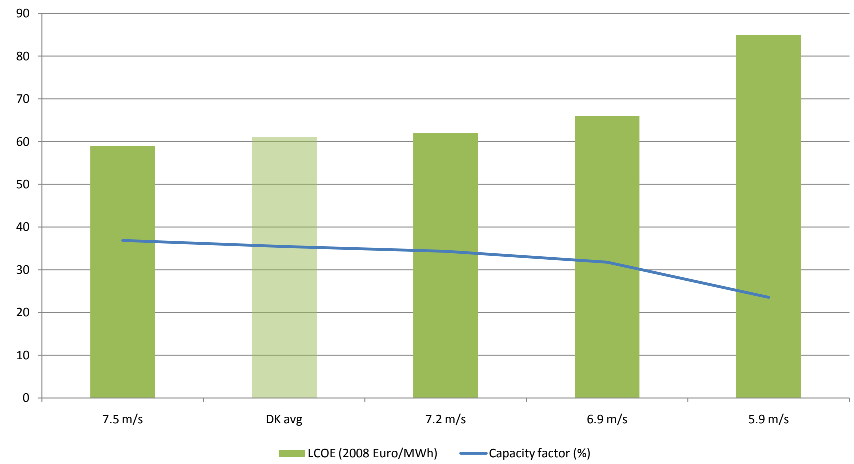
LCOE 2009



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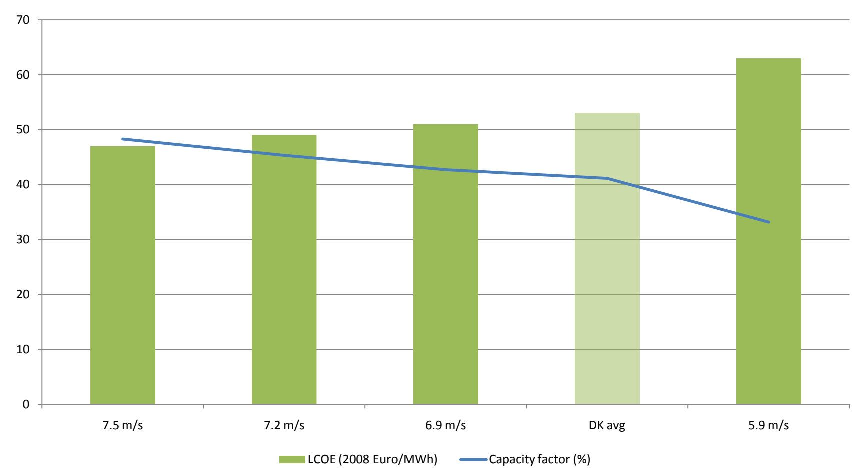
LCOE 2012



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Ea Energy Analyses

Remarks

- The average LCOE for turbines commissioned or ordered for commissionining fell from €65 in 2002 to €60 in 2009 and €53 in 2012.
- A comparison of calculated LCOE for 2002, 2009, and 2012 indicates that higher wind sites were required in 2009 to bear the higher costs of turbines despite higher performance than in 2002.

7 Ea Energy Analyses

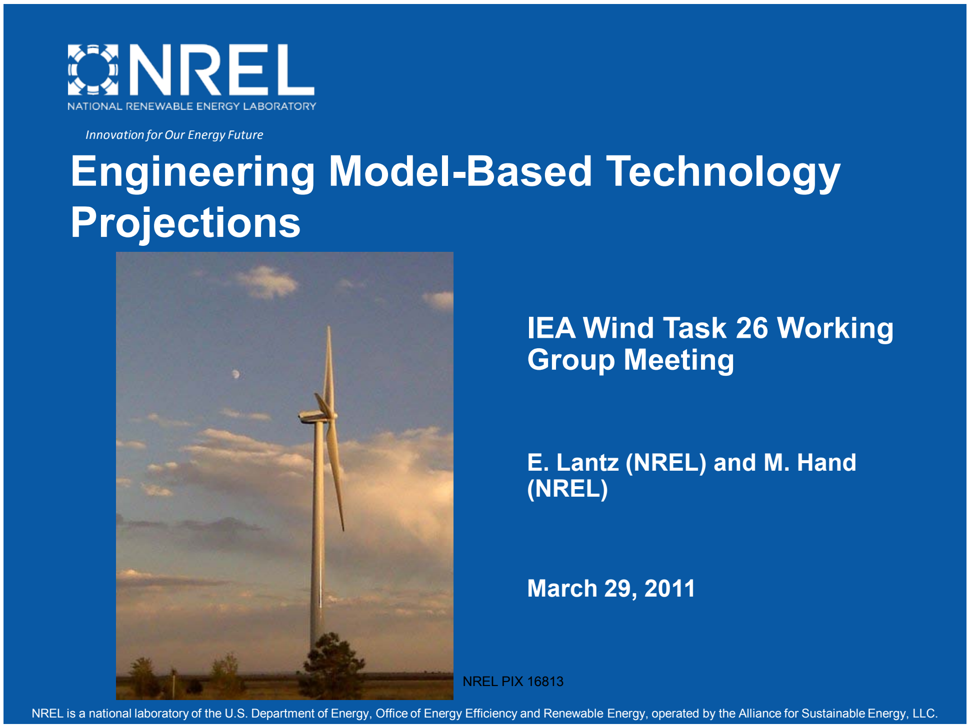
Comparison of Turbines with Danish Support Program

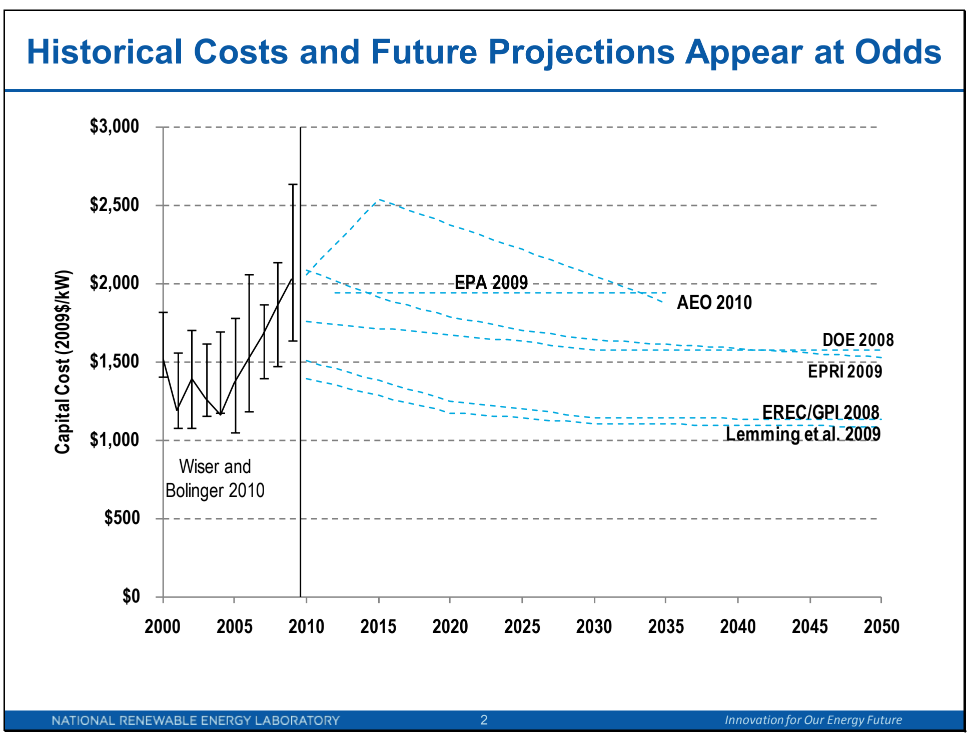
	Price (2008 Euro)/ Kilowatt [kW])	Turbine	Megawatt-hour (MWh)/ Megawatt (MW)	EUR/MWh	Relative price	Income: subsidy (M€)	Income: market (M€)	Total (M€)	Income/ project price	Relative value
2002	1104	0.9 kW	2209	500	1	0.66	2.12	2.78	2.79	0.85
2009	1438	3 MW	3102	464	0.93	2.2	9.9	12.13	2.81	0.86
2012	1400	3 MW	3602	389	0.78	2.2	11.52	13.73	3.27	1

Average market price used: EUR53/MWh
Subsidy: EUR33/MWh for 22,000 full load hours
Balancing subsidy and balancing costs not included
Current subsidy regime used for 2002 turbines. Another subsidy regime was in place at the time.

8 Ea Energy Analyses

Engineering Model-Based Technology Projections





Attempting to Reconcile Recent Trends and Cost Projections Generates Critical Questions

Working Premises

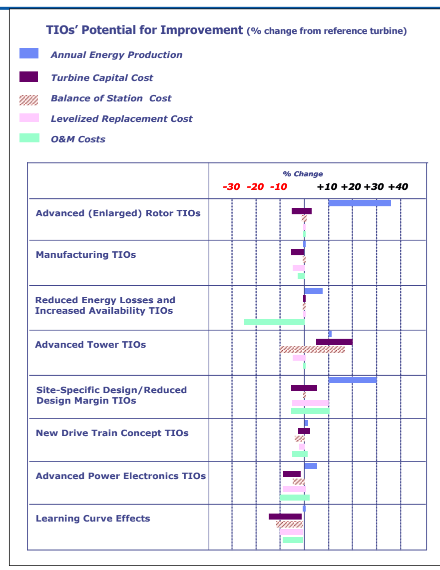
- Cost of energy (not installed cost) is the design driver
- Turbine manufacturers must balance lower installed costs against increased performance

Applicable Questions

- Are projections of lower installed costs *and* increased performance realistic?
- What level, and in what turbine system(s), of innovation is required to achieve installed cost and performance projections?

Learning Curve Alternatives: Expert Elicitation

- **Survey industry experts to gather a range of possible technology outcomes**
- **Develop probability distributions associated with various technical outcomes**
- **Example**
  - **U.S. Department of Energy (DOE) Risk Analysis project conducted in association with WindPACT analytic studies**



Note: TIO =Technology Improvement Opportunity;
O&M = Operations and Maintenance
Source: Cohen et al., 2008

Learning Curve Alternatives: Engineering Model

Bottom-up, component-level, system analysis

1. **Evaluates tangible technology advancements:** proposed and anticipated technology advancements, with a focus on realizable opportunities
2. **Measures the potential value of individual innovations:** specific opportunities are quantified independently, and results are combined to arrive at a cost estimate
3. **Considers installed cost and technology performance:** allows weighting of tradeoffs between cost increases and improvements in energy capture
4. **Offers the opportunity to substantiate a learning curve projection:** creates a pathway to a future point

Requires simplification of complex engineering problems

Does not typically represent economy of scale or volume-based cost improvements explicitly

NATIONAL RENEWABLE ENERGY LABORATORY 5 *Innovation for Our Energy Future*

NREL's Wind Turbine Design and Cost Scaling Model

Flexible, modular, spreadsheet model:

- Perform trade-off studies of turbine technology options
  - *Determine technology changes with the greatest potential to reduce cost of energy (COE)*
- Generate wind technology cost and performance trajectories
  - *Used in generation capacity expansion modeling*

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Cost Model Features

Permits scaling of components to analyze turbine configurations

- Costs based on DOE WindPACT analysis (and development subcontracts)
- Includes simple and advanced scaling curves

Illustrates some technology pathways in relation to industry

- Pathways based on industry trends and WindPACT analysis

Validated using industry data where possible

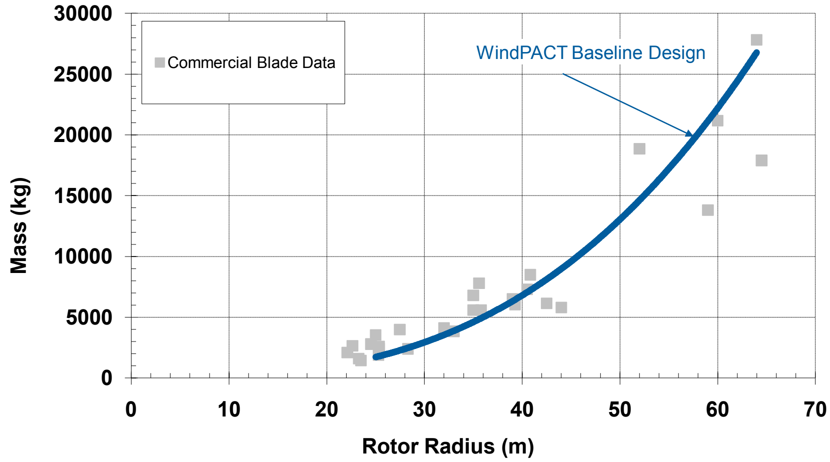
Cost Model Functional Overview

Spreadsheet tool consists of two primary elements:

1. *Cost and scaling calculator(s)*
   - Series of models for individual turbine components (e.g., blades, hub, low-speed shaft, pitch mechanisms, and mainframe)
   - Most relationships are simple functions of rating, rotor diameter, and hub height
   - Does not directly consider variable cost of capital or supply and demand market price pressures

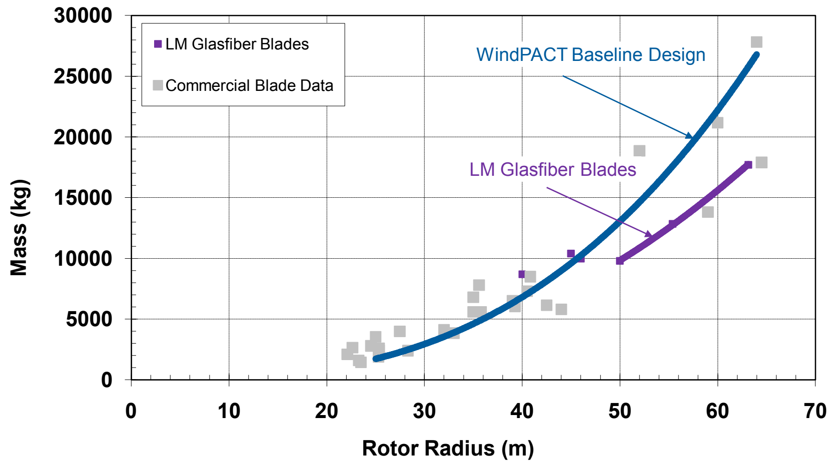
2. *Simplified energy production calculator*
   - Assumes equivalent blade geometry and airfoil performance
   - Only utilizes the peak coefficient of power (Cp)
   - Operational range divided into ¼ meter (m) per second (s) bins, for each bin hub power, drive-train efficiency, and total energy are calculated, energy capture and capacity factor are computed from totals

Wind Turbine Blade Innovation Pathway



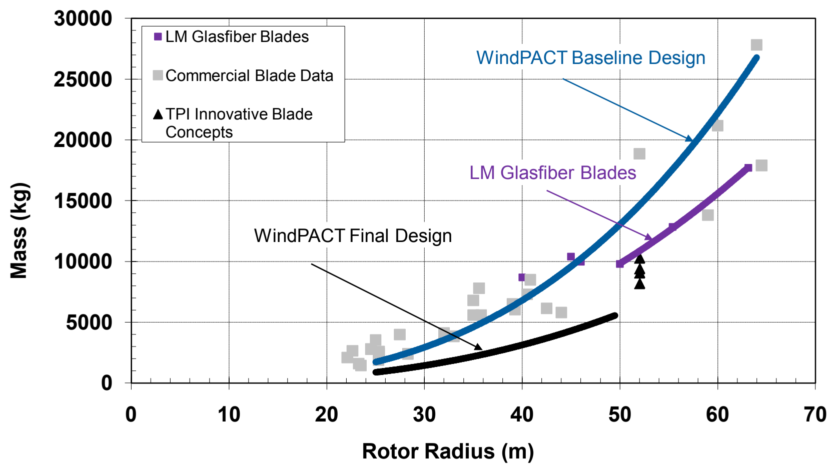
Source: Based on Fingersh et al., 2006

Wind Turbine Blade Innovation Pathway



Source: Based on Fingersh et al., 2006

Wind Turbine Blade Innovation Pathway



Source: Based on Fingersh et al., 2006

NREL Engineering Model Analysis Scope

Objective

- Quantify the value of potential technological advancements on larger turbines
- Evaluate the feasibility of achieving the U.S. 20% wind cost and performance trajectory while simultaneously moving to 5-megawatt (MW) turbines

Approach

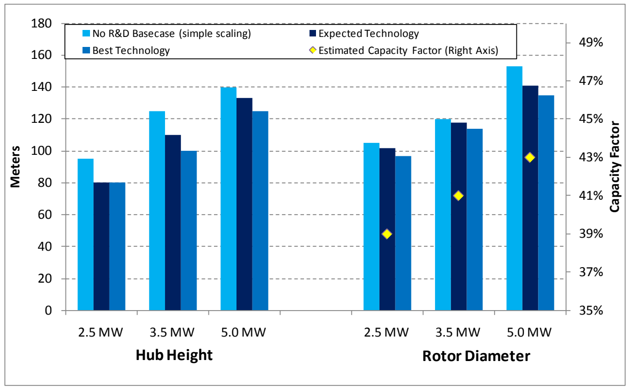
- Develop hypothetical turbines that are in line with the 20% wind study, to achieve 20% wind performance trajectory, and scale gradually to 5-MW
- Apply individual technological improvements to those turbines to evaluate their impact on installed cost and turbine capacity factors

Caveats

- Emphasis on incremental technology and marketplace changes
- Innovations must be adopted widely
- Continued analysis of how balance-of-plant (BOP) costs are affected by larger turbines and consideration of emerging innovation strategies would further enhance our understanding

Land-based Wind Technology Development Pathway to Achieve 20% Wind Targets

preliminary



Drivetrain Design

	2.5 MW	3.5 MW	5.0 MW
No Research and Development (R&D) Basecase (Simple Scaling)	**3-stage geared**		
Expected Technology	**multi-generator**	**single-stage geared**	**direct drive**
Best Technology			

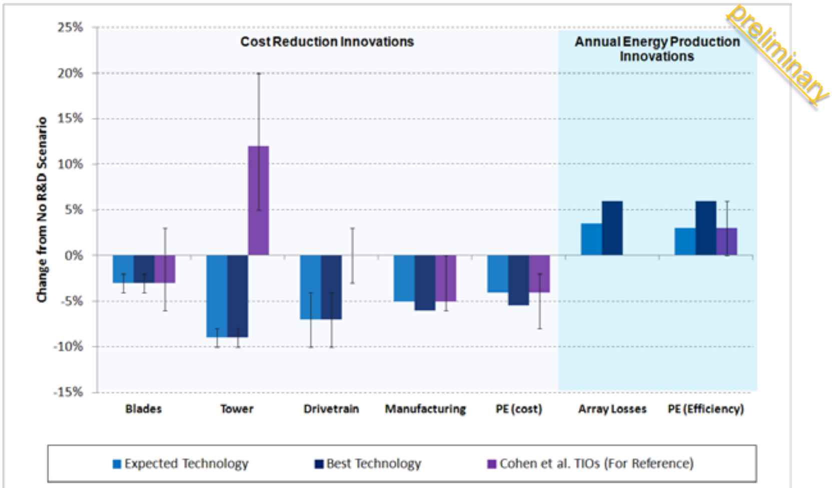
Notes: Technology scenario labels are generally defined by WindPACT risk analysis and summarized in Cohen et al. 2008. Individual turbine designs are optimized to reach capacity factor targets of the 20% wind study; capacity factor targets assume continued scaling of turbines, hence, higher capacity factor targets are expected for larger machines.

Technology Captured by Inputs Range

preliminary

Turbine Cost Reduction	Innovations Reflected in the Advanced Technology Parameters	Input Data Source
Blade Technology	•Enhanced structural design, targeted reinforcement •High-tech composites possibly including carbon fiber	Cost and scaling model advanced technology scaling curves
Tower Technology	•Tower feedback to blade pitch controls •Flap-twist coupling in blade design •Reduced blade chord with tip speed increase	
Drivetrain Technology	•Multi-generator drivepath •Single-stage, medium-speed gearbox •Direct drive	
Manufacturing Efficiency	•Increased automation •Improved resins with greater ease of use •Reduced design margins resulting from more consistent fabrication •Reduced profit margins as a result of increased volume	Cohen et al. 2008 TIOs (WindPACT Risk Analysis)
Power Electronics	•High-voltage circuitry •Multi-switch capacity •Semi-conductor devices	
Annual Energy Production (AEP) Increase		
Reduced Losses	•Improved micro-siting to reduce array losses •Real-time monitoring and operational modifications •Low soil blades	Industry estimates
Power Electronics (Higher Efficiency)	•High-voltage circuit topologies •Multi-switch capacity	Cohen et al. 2008 TIOs

Modeling Changes to Cost and Performance



Note: One additional scenario considers best technology improvements combined with scaling at today's blade and nacelle mass ratios (i.e., scaling with proportionally comparable masses for blades and nacelles to those observed in the industry today).

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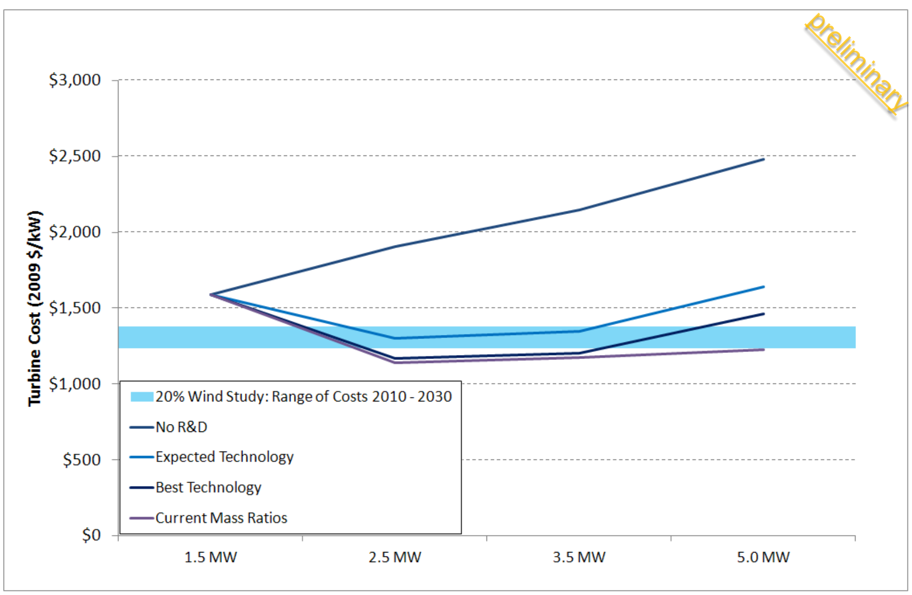
Advanced Technology Permits Scaling to 3.5-MW with Reduced Costs and Increased Performance



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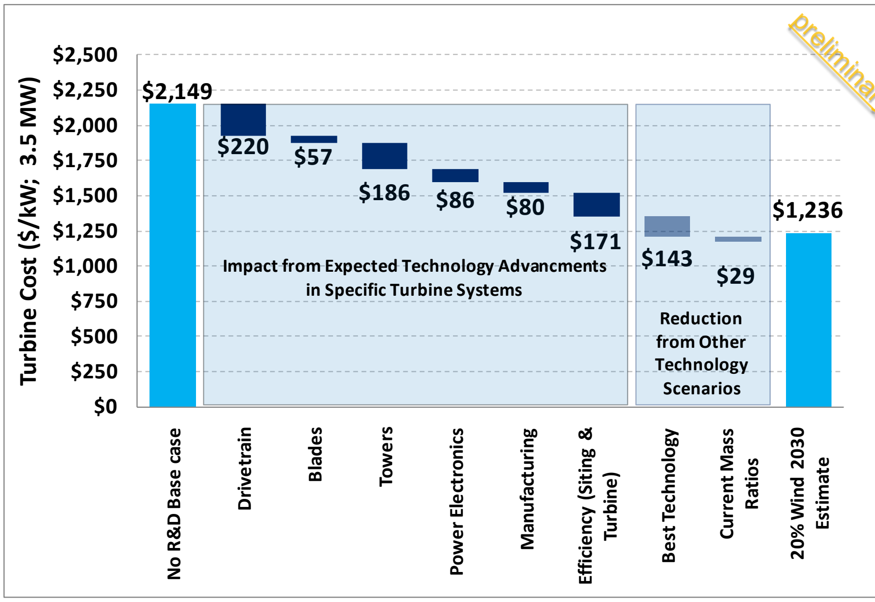
Incremental Advancements Across All Turbine Components/Systems Are Necessary



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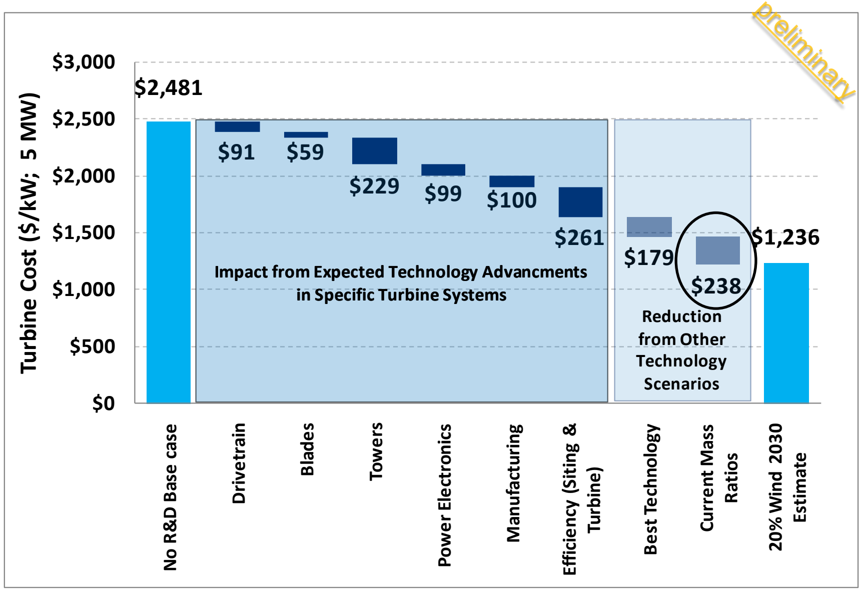
Additional Technology Advancement is Required to Achieve Cost and Performance Targets at 5.0-MW



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Conclusions

1. It is not unreasonable to expect significant turbine cost reductions (20%) while increasing turbine performance, when excluding short-term market dynamics.
   - Based on technological change, we can generally reconcile future cost reductions with recent trends.

2. Modest cost/performance projections (i.e., 20% wind) can be achieved, but 5.0-MW machines will require all of the advanced technology captured in this analysis and then some.

3. All turbine systems can contribute to future cost reductions.
   - Advanced tower designs and reduced losses appear to offer the greatest potential to minimize costs while maintaining performance.

4. If existing prototypes and recently commercialized equipment prove viable, these cost reductions may be closer than we think.

Questions

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aee

ON-SHORE WIND IN SPAIN

Credit: AEE

Heikki Willstedt Mesa
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Dirección Políticas Energéticas
Asociación Empresarial Eólica

Web2Present Webinar Series- Wind Power 2011

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MAIN ISSUES

- **WHY A SUCCESS STORY?**
  - Early mover (90s)
  - Feed-in tariff (no system changes)
  - Utilities among the main developers
  - Own industry with research and development (R&D) and investment
- **CURRENT SITUATION 2010**
  - Fourth country in installed power in the world (second in the European Union [EU]) with 20,676 megawatts (MW)
  - First country in the EU with a wind power generation of 42.7 terawatt-hours (TWh)
  - Second country in the world with a wind power penetration of 16.4%
  - Spanish companies had 9,200 MW installed outside the country
- **CHALLENGES AHEAD**
  - Achievement of the National Renewable Energy Action Plan (NREAP) objective of 35,000 MW on-shore and 3,000 MW off-shore
  - Grid and storage integration (e.g., pumped storage, electrical vehicles, and other storage)

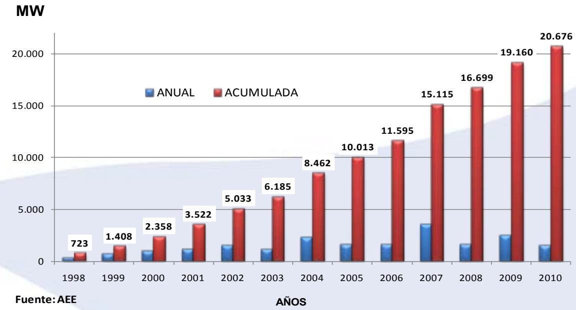
1.

Wind energy: Context and Situation

ENERGY AND ENVIRONMENTAL CONTEXT

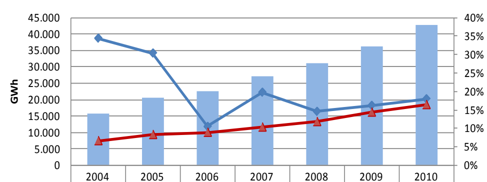
- The external energy dependence of the European Union is over 50% and it is forecasted to be above 70% by 2020. Energy diversification is a priority in the European energy policy and reducing energy dependence is a geostrategic necessity.
- In 2007, the rate of external energy dependence of Spain reached 85.1% which is a strategic weakness and a burden on the trade balance. The current rate is 79%.
- According to the commitments made within the Kyoto Protocol, Spain aims to limit carbon dioxide (CO_2) emissions by more than 15% (reference 1990), but it closed 2007 with a 52% increase. Currently (2010), the rate is at +24%–28%.
- The long construction period for conventional power stations and the uncertainty of fossil fuel prices prices triggers the need to use wind energy as a source of electrical generation.

IMPORTANT AND CONTINUOUS GROWTH OF WIND POWER IN SPAIN



- Renewable Energies Plan (2005–2010): 20,155 MW
- Official network planning for 2016: 29,000 MW
- Further increase expected for compliance with the goal of 20% of energy demand with renewable technologies ≅ 40% -> 38,000 MW.

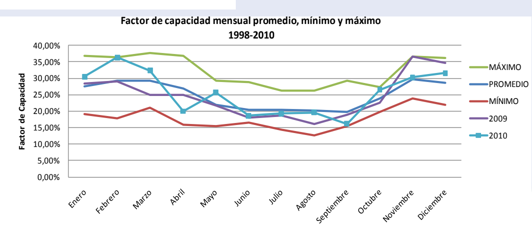
WIND POWER PRODUCTION AND CAPACITY FACTOR



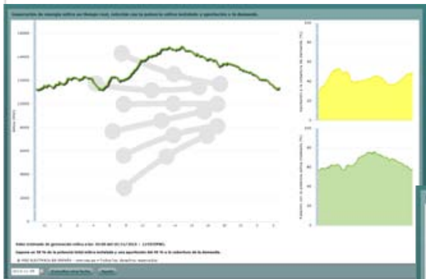
	2004	2005	2006	2007	2008	2009	2010
Generación eólica	15.744	20.520	22.684	27.169	31.136	36.188	42.702
Tasa de variación eólica (%)	34,3%	30,3%	10,5%	19,8%	14,6%	16,2%	18,0%
Cobertura de la demanda (%)	6,7%	8,3%	8,9%	10,3%	11,8%	14,4%	16,4%

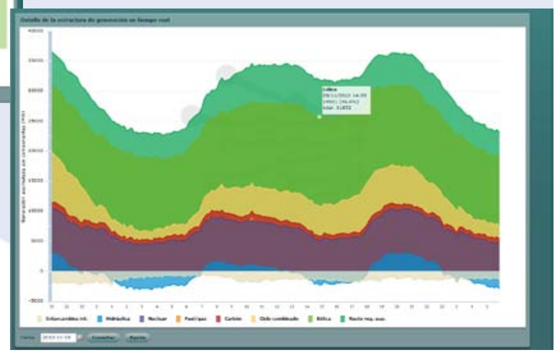
Fuente: REE

- Wind production increases due to the growth of installed power, but individual wind farms have reduced their capacity factor up until 2008. In 2009 and 2010, the capacity factor has increased.
- Wind production remains constant for long periods of time.
- The maximum coverage was 53% of the total demand.



DEMAND COVERAGE HISTORIC HIGH 9/11/2010





Source: REE

7

2.

Main Technical Challenge: Integration of Wind Energy into the Grid

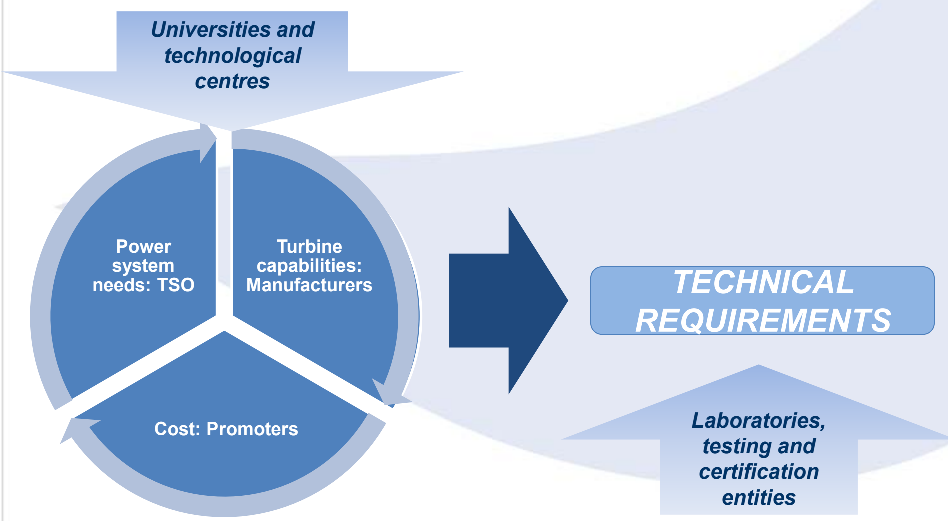
Spain is an "Electrical Island"

THE INTEGRATION OF WIND ENERGY RAISES SOME CHALLENGES

- Technical challenges:
  - Reaction of wind farms to voltage drops: contribution to grid stability
  - Voltage control
  - Grid security and safety.
- System operation challenges:
  - Wind production program: affects the deviations and the use of ancillary services
  - Coordinated operation of generation units.

9

THE ANSWER TO THOSE CHALLENGES REQUIRES THE DEFINITION OF THE TECHNICAL REQUIREMENTS



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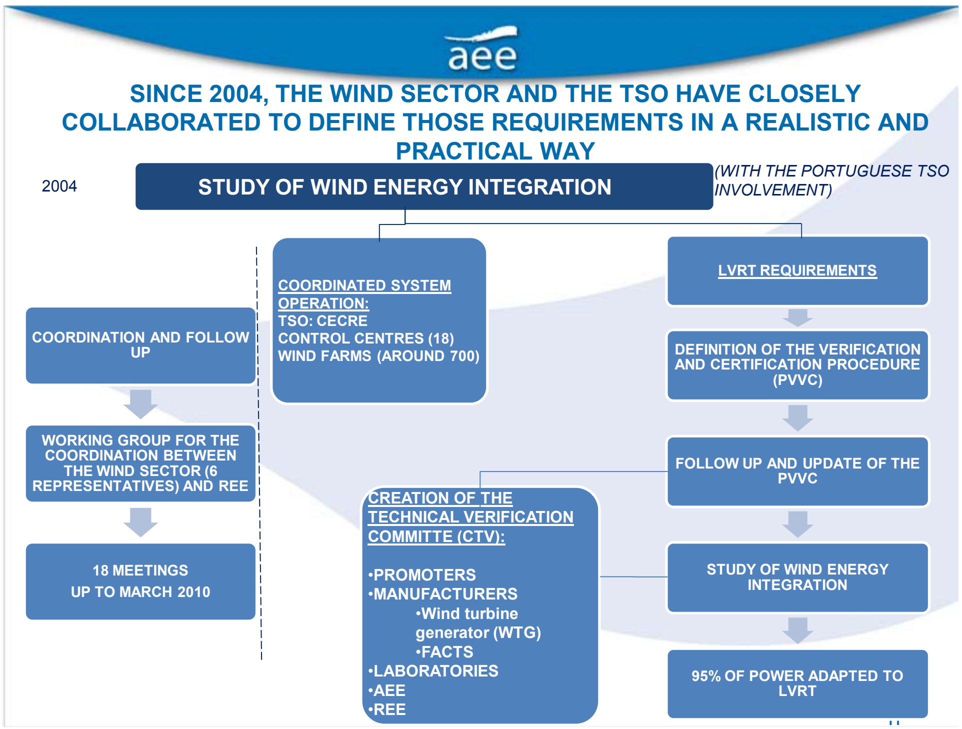
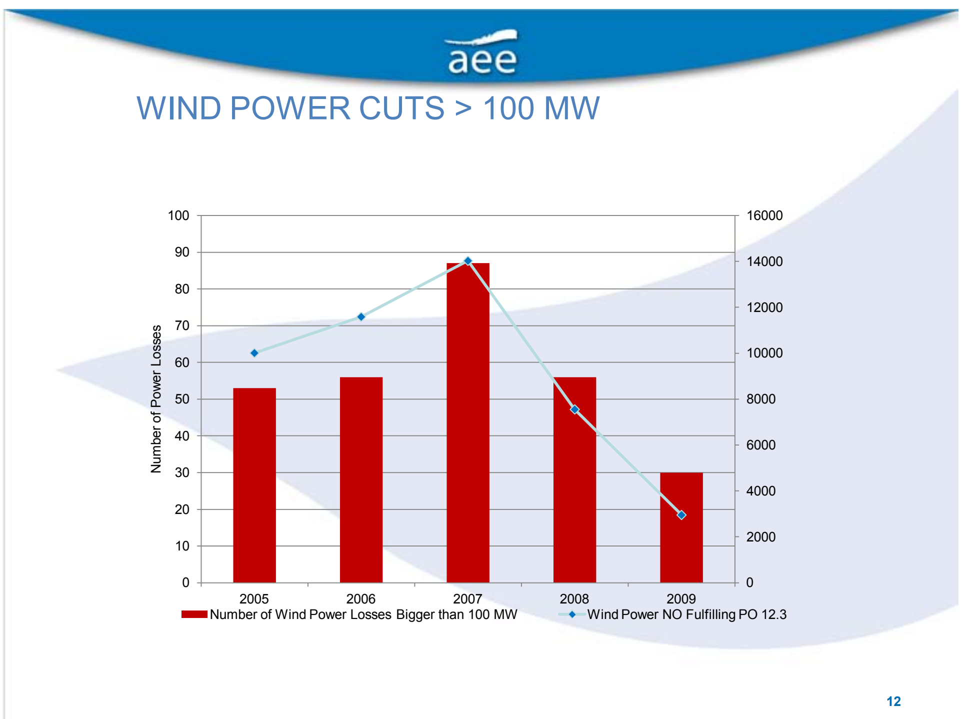

aee
SINCE 2004, THE WIND SECTOR AND THE TSO HAVE CLOSELY COLLABORATED TO DEFINE THOSE REQUIREMENTS IN A REALISTIC AND PRACTICAL WAY
2004
STUDY OF WIND ENERGY INTEGRATION
(WITH THE PORTUGUESE TSO INVOLVEMENT)
COORDINATION AND FOLLOW UP
WORKING GROUP FOR THE COORDINATION BETWEEN THE WIND SECTOR (6 REPRESENTATIVES) AND REE
18 MEETINGS
UP TO MARCH 2010
COORDINATED SYSTEM OPERATION:
TSO: CECRE
CONTROL CENTRES (18)
WIND FARMS (AROUND 700)
LVRT REQUIREMENTS
DEFINITION OF THE VERIFICATION AND CERTIFICATION PROCEDURE (PVVC)
FOLLOW UP AND UPDATE OF THE PVVC
STUDY OF WIND ENERGY INTEGRATION
95% OF POWER ADAPTED TO LVRT
CREATION OF THE TECHNICAL VERIFICATION COMMITTE (CTV):
•PROMOTERS
•MANUFACTURERS
•Wind turbine generator (WTG)
•FACTS
•LABORATORIES
•AEE
•REE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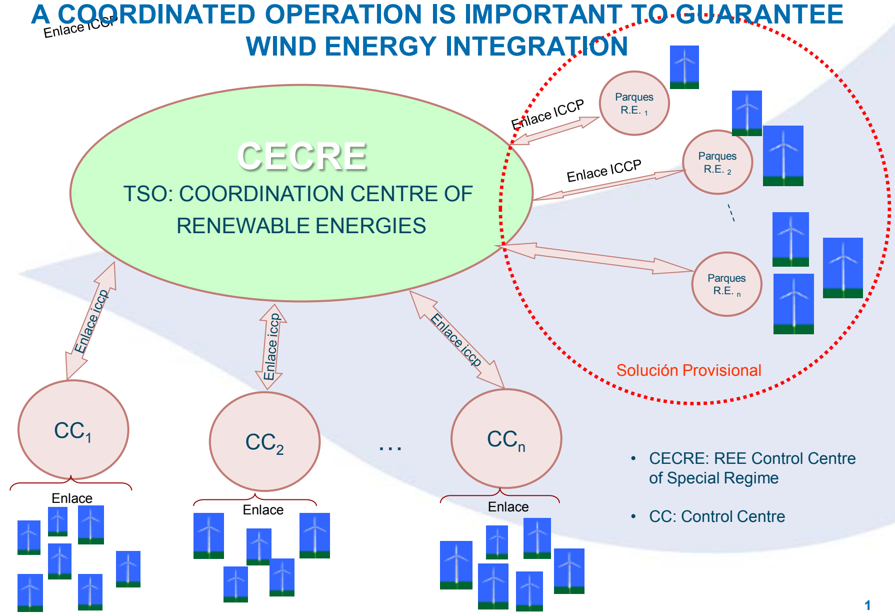
WIND POWER CUTS > 100 MW
Number of Power Losses
100
90
80
70
60
50
40
30
20
10
0
16000
14000
12000
10000
8000
6000
4000
2000
0
2005
2006
2007
2008
2009
Number of Wind Power Losses Bigger than 100 MW
Wind Power NO Fulfilling PO 12.3
12

A COORDINATED OPERATION IS IMPORTANT TO GUARANTEE WIND ENERGY INTEGRATION



- CECRE: REE Control Centre of Special Regime
- CC: Control Centre

1

CECRE: OBJECTIVES AND FUNCTIONS

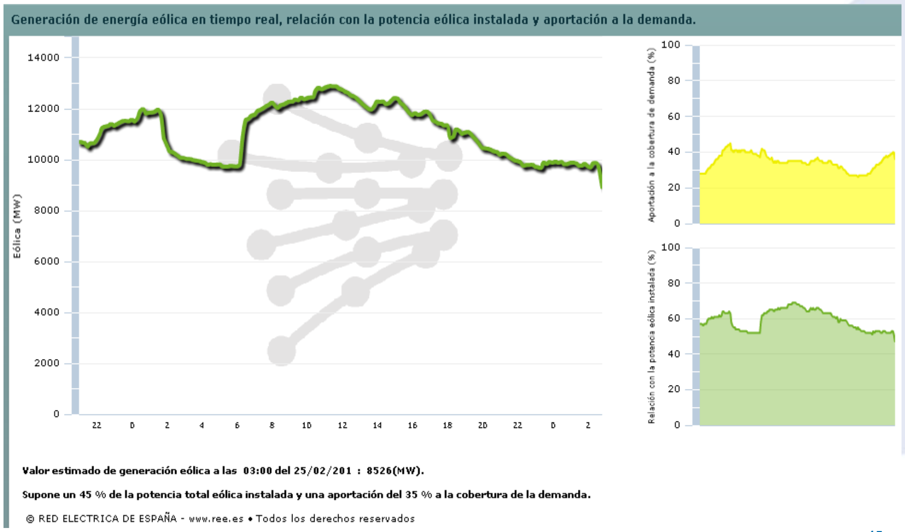
- Main function: To achieve a greater level of integration for renewable energy sources without compromising the system s security.
  - Improves security and effectiveness in the system s operation
  - Allows substitution of permanent preventive criteria for real-time production control.

GEMAS

- Real-time risk assessment due to voltage dip wind generation losses
- Calculation of wind production limitations
- Filter limits for stable solutions in accordance with legislation.

14

AN UNDESIRED SITUATION: WIND POWER REDUCTION AFTER CECRE ORDER (24/2/2010)



15

3.

The Spanish Market

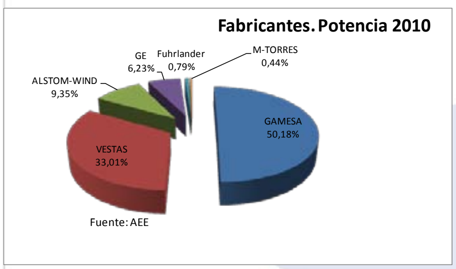
MAIN PLAYERS IN THE SUPPLY CHAIN OF WIND ENERGY IN SPAIN

Main players in major activity areas include:

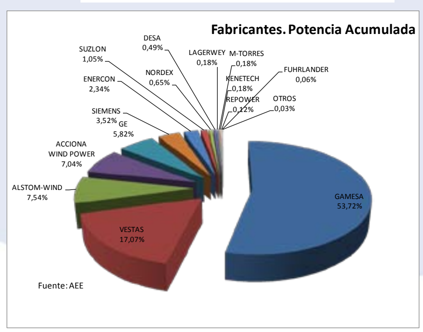
Raw materials Energy Shipping Etc.	Manufacture of key components	Manufacture of wind turbines	Project development, construction, financing, and so on	Service operation, maintenance, and sale of electricity
	HANSEN WINERGY MOVENTAS ECHESA SKF FAG / INA TIMKEN LM GLASSFIBER FIBERBLADE ...	VESTAS GE Wind GAMESA ENERCON SIEMENS NORDEX ALSTOM ACCIONA M TORRES REPOWER SUZLON ...	IBERDROLA ACCIONA NEO ENERGÍA (HC) ECYR (ENDESA) EUFER (UN. FENOSA) GAS NATURAL ENERFÍN EYRA (ACS) EON EOLIA MOLINOS DEL EBRO	GES IMFUTURE GUASCOR SERVICIOS INGETEAM REETEC EFACEC SBS

BREAKDOWN BY MANUFACTURERS

BREAKDOWN BY MANUFACTURERS OF INSTALLED WIND POWER IN 2010



BREAKDOWN BY MANUFACTURERS OF ACCUMULATED WIND POWER AT THE END OF 2010



More than 700 companies—from manufacturers to financial services—have some kind of involvement in the wind energy sector.

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A SOLID INDUSTRIAL NETWORK TO SUPPORT THE NATIONAL AND EXTERNAL MARKETS

Spanish wind sector industrial centres

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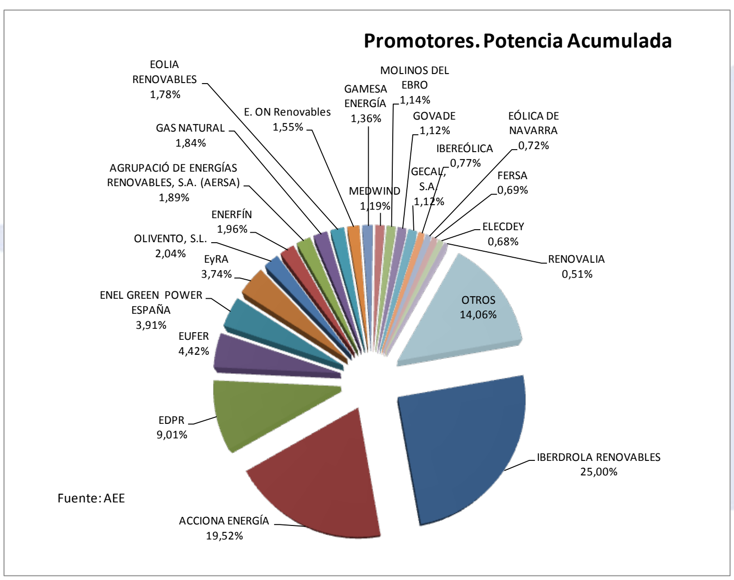
PROMOTERS: ACCUMULATED INSTALLED POWER IN 2010



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4.

An Adequate Legal Framework Until 2009

A STABLE LEGAL FRAMEWORK IS ESSENTIAL FOR THE DEVELOPMENT OF THE WIND SECTOR

- The 2007 Royal Decree, in force from 06/01/07, allows two remuneration options:
  - Regulated tariff
  - Market price and premium: with a cap and floor for the premium
- Wind farm installations governed by the previous regulation (RD 436/2004) had until 01/01/2009 to decide whether they will continue with it or choose the new RD
- Remuneration updated using the RPI, less an adjustment factor (0,25% until 2012, 0,5% from then on).

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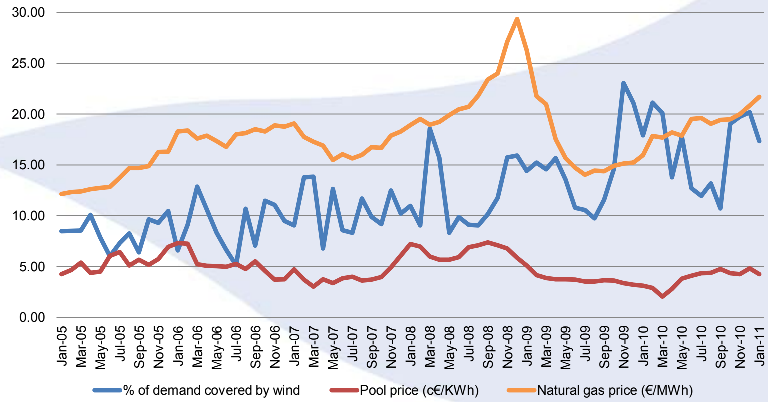
WIND POWER HELPS KEEP POWER MARKET PRICES LOWER THAN DURING THE PREVIOUS OIL SHOCK IN 2008

% of demand covered by wind versus market and gas prices in the Spanish power sector



Sources: CNE, OMEL, and REE

In 2008, the price of the market was so high that during 3% of the hours, wind power did not receive premiums.

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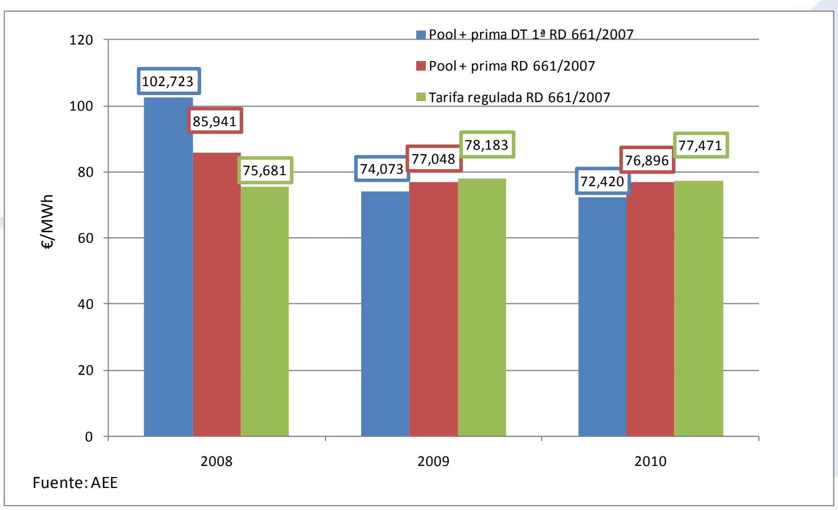
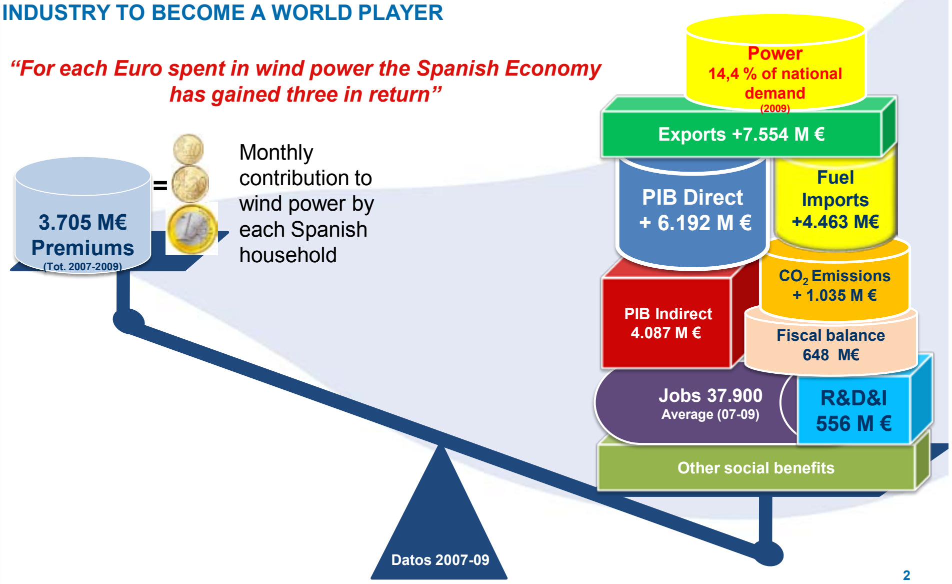
WIND FARMS REMUNERATION



24

THE SPANISH FEED-IN TARIFF HAS MADE POSSIBLE THE ACHIEVEMENT OF THE 2010 RES ELECTRICAL OBJECTIVE, AND AS A BONUS HAS ENABLED THE SPANISH WIND INDUSTRY TO BECOME A WORLD PLAYER

"For each Euro spent in wind power the Spanish Economy has gained three in return"

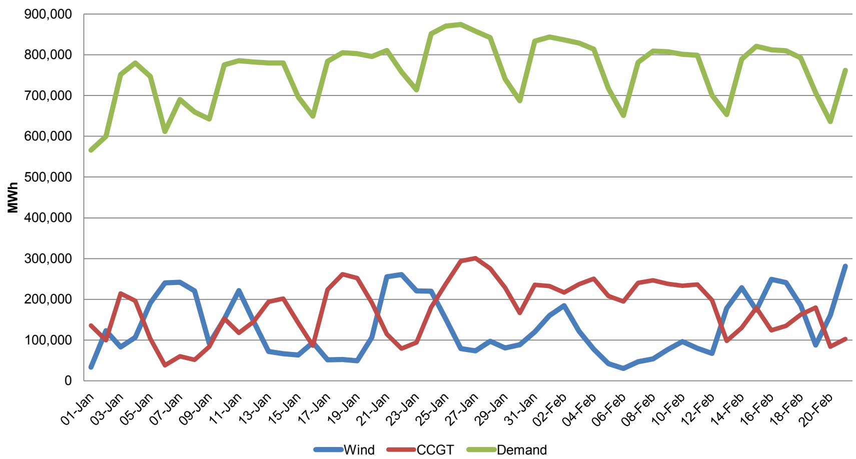


5.

Challenges Ahead

WIND POWER AND OTHER TECHNOLOGIES: INTEGRATION

Wind and CCGT generation (Jan-Feb/2011)

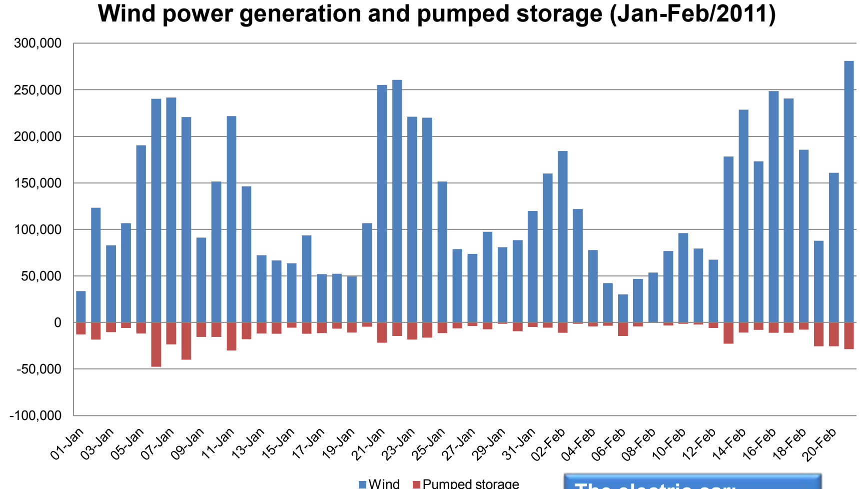


Source: REE

27

WIND POWER AND STORAGE: ARE THERE INCENTIVES TO MAKE IT WORK TO ITS FULL POTENTIAL?

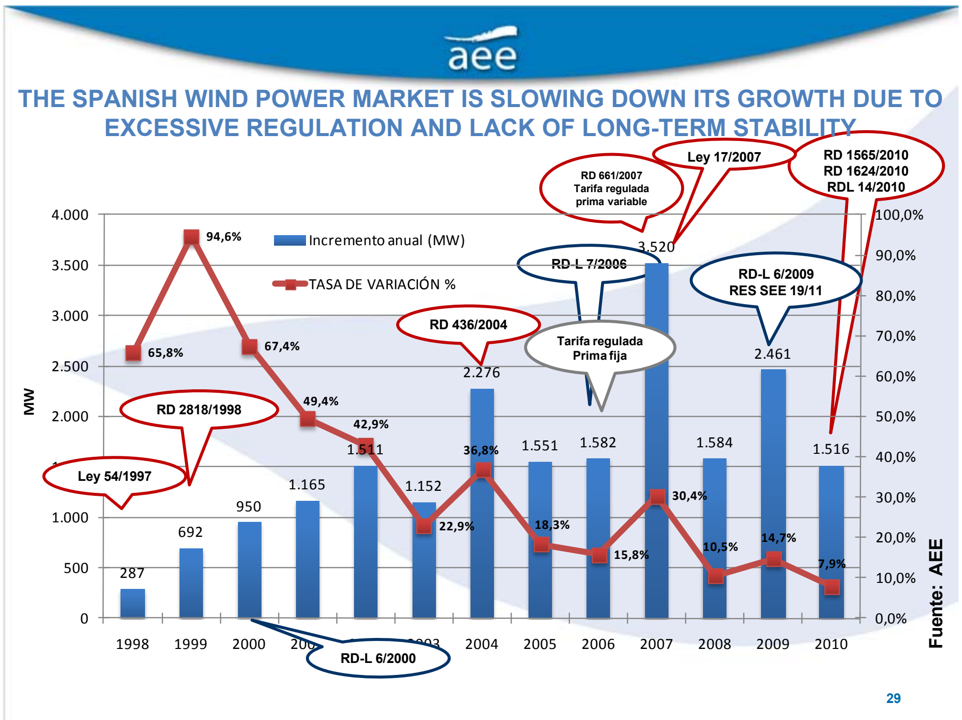
Wind power generation and pumped storage (Jan-Feb/2011)

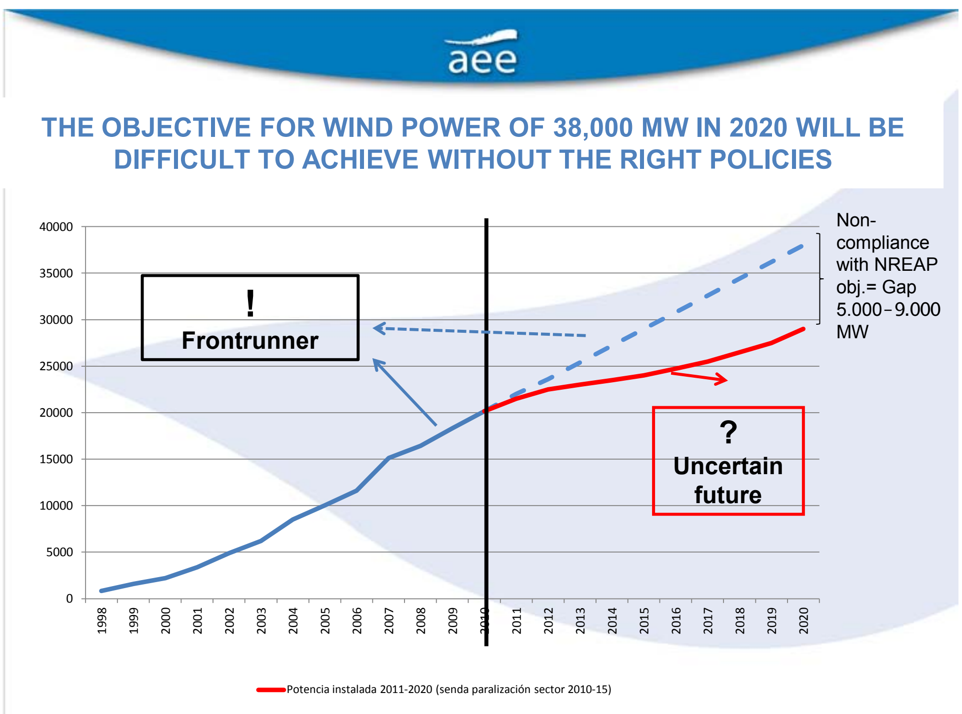


Source: REE

The electric car: a reality after 2015?

28


THE SPANISH WIND POWER MARKET IS SLOWING DOWN ITS GROWTH DUE TO EXCESSIVE REGULATION AND LACK OF LONG-TERM STABILITY
Incremento anual (MW)
TASA DE VARIACIÓN %
MW
Ley 54/1997
RD 2818/1998
RD-L 6/2000
RD 436/2004
RD-L 7/2006
Tarifa regulada Prima fija
RD 661/2007 Tarifa regulada prima variable
Ley 17/2007
RD-L 6/2009 RES SEE 19/11
RD 1565/2010 RD 1624/2010 RDL 14/2010
Fuente: AEE
29


THE OBJECTIVE FOR WIND POWER OF 38,000 MW IN 2020 WILL BE DIFFICULT TO ACHIEVE WITHOUT THE RIGHT POLICIES
!
Frontrunner
?
Uncertain future
Non-compliance with NREAP obj.= Gap 5.000-9.000 MW
Potencia instalada 2011-2020 (senda paralización sector 2010-15)

CONCLUSIONS

- The on-shore wind energy sector has become a world player due to the extraordinary development of the Spanish market, spurred by ambitious objectives, an efficient feed-in tariff system, and the involvement of the main utilities.
- The collaboration between the Spanish wind sector and the TSO has been very fruitful and essential to guarantee the integration of wind energy in the electrical system.
- The development of wind energy in Spain has also been backed by an important industrial capacity and now the main challenge is to maintain a competitive position in the global market.
- To achieve the 2020 NREAP objectives for wind power, a long-term policy framework is necessary to attract investments in an increasingly competitive European wind market.

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THANK YOU FOR YOUR ATTENTION!

Credit: AEE

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Dirección Políticas Energéticas
Asociación Empresarial Eólica

Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects

Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects

Ryan Wiser, Lawrence Berkeley National Laboratory
Eric Lantz, National Renewable Energy Laboratory
Mark Bolinger, Lawrence Berkeley National Laboratory
Maureen Hand, National Renewable Energy Laboratory

February 2012

This analysis was funded by the Wind & Water Power Program, Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231

Background and Motivation

- Some recent focus has been placed on the increasing capital cost of wind projects observed from the early 2000s to 2010, and the apparent flattening of fleet-wide capacity factors in recent years
- These trends are important, but ignore other developments:
  - Continued improvements in capacity factors within individual wind resource classes (if not fleet-wide) due to hub height and rotor diameter scaling
  - Significant recent improvements in low-wind-speed technology, resulting in increased capacity factors and increased land area open to development
  - Steep reductions in turbine prices negotiated in last 2 years, and some evidence of reductions in balance of plant costs → expected (with some lag) to lead to sizable near-term reductions in project-level capital costs
  - Possible longer-term (i.e., since early 2000s) reductions in the cost of operating and maintaining as well as financing wind projects, as well as potentially improved turbine/project availability
  - Incentive choice with respect to 30% ITC/1603 Treasury grant in lieu of PTC

Background and Motivation

- Exclusive focus on *historical capital cost* and *fleet-wide capacity factor* trends fails to convey recent improvements in the levelized cost of energy (LCOE) from wind projects, the opening of new lower-wind-speed areas for development, and the fundamental interdependency of capital costs and capacity factors
- Wind turbine manufacturers, wind project developers, and wind power purchasers are not focused solely on optimizing capital costs and capacity factors, individually, but are more interested in:
  - Levelized cost of wind energy across all wind resource classes
    - Lower LCOE → lower power sales prices → greater demand for wind energy
  - Amount of land area that might be reasonably developed
    - Transmission/siting/policy influences can constrain development in high-wind-resource regimes → opening new lower-wind-resource regimes for development can significantly increase potential development opportunities

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Objectives of Present Work

(1) Develop consistent ***levelized cost of energy*** estimates for wind in the U.S. in various wind resource regimes for:
- Projects installed in 2002-2003: The low-point of wind capital costs
- Projects installed in 2009-2010: The likely peak of wind capital costs
- Projects to be installed in 2012-2013: When current turbine pricing is likely to more-fully make its way into observed capital costs

Focus on direct costs, accounting primarily for **capital cost** trends and trends in estimated **capacity factors**; conduct analysis with/without PTC/MACRS; emphasize, only as an example, GE turbines

(2) Estimate the amount of **available land area** that would exceed certain capacity factor and LCOE thresholds using the same assumed technology, assumptions, and time periods as above

(3) Conduct two side-case analyses: (1) impact of **incentive choice** between PTC and ITC/Section 1603; and (2) impact of possible **O&M, financing, and availability trends**

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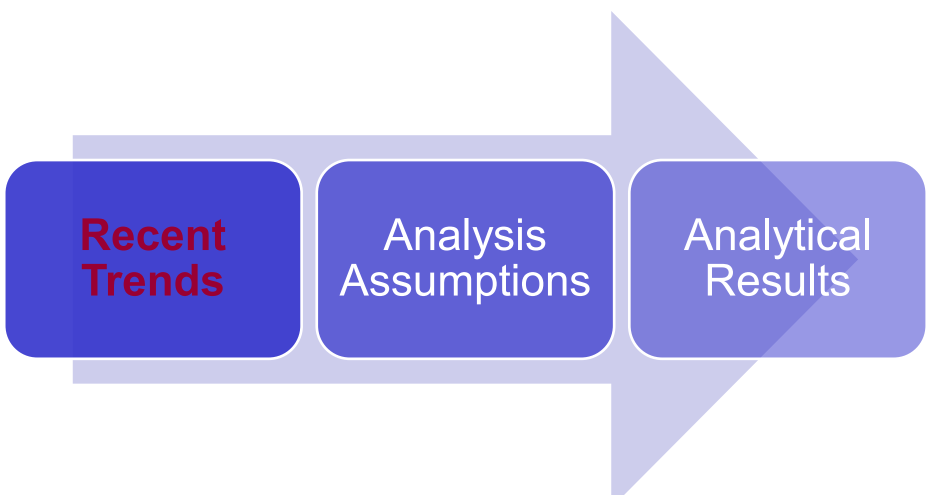
Caveats

- This is a preliminary assessment of the impact of various trends on LCOE; the analysis does not consider all factors, and the results have not undergone rigorous peer-review or been published
- The analysis uses GE turbine technology only as an example to facilitate assessment
- This work only seeks to understand and estimate recent and near-term developments
- LCOE estimates for 2012-2013 are based on current turbine pricing, but are nonetheless speculative
- This work has not attempted to track developments over a longer historical record or to forecast longer-term future trends
- The present analysis is focused on the U.S., though the basic findings should hold for other regions of the world as well

Presentation Outline



Datasets Used To Explore Recent Capital Cost and Performance Trends

Project- and Turbine-Level Capital Costs

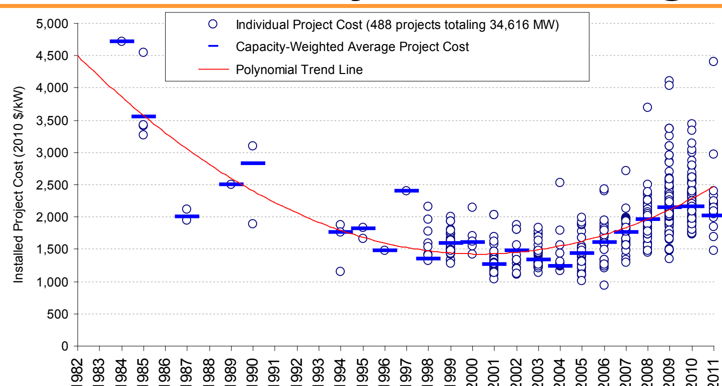
- 488 projects built from 1983-2011, 34.6 GW
- 81 turbine transactions from 1997-2011, 23.9 GW

Project-Level Performance / Capacity Factors

- 338 projects built from 1983-2009, 32.0 GW

Data shown here are primarily from the U.S. DOE's *2010 Wind Technologies Market Report ("U.S. DOE 2011")*

Installed Wind Project Capital Costs Increased from Early 2000s through 2010



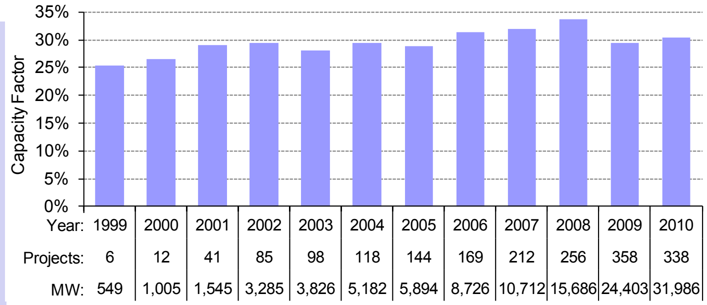
Source: U.S. DOE 2011

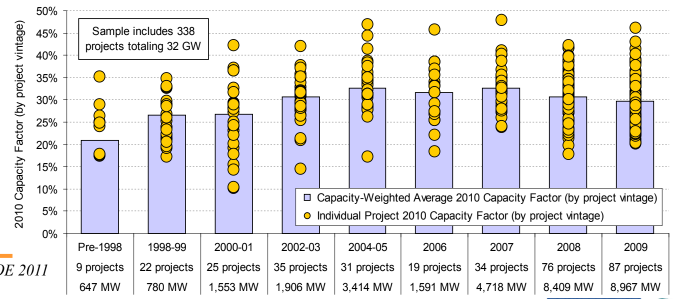
Project costs bottomed out in 2001-2004; rose by $850/kW on average through 2009; held steady in 2010 ($2,155/kW); based on limited available data, may have dropped in 2011

Fleet-Wide Capacity Factors (CF) Have (Generally) Increased Over Time

BUT:

Some leveling off in ***fleet-wide*** capacity factors in recent years is also apparent





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Source: U.S. DOE 2011

Historical Trends Important, But Ignore Other Notable Developments

Project Performance	• Sizable historical/continued increases in hub heights and rotor swept area (in proportion to nameplate capacity), leading to improvements in capacity factors within individual wind resource classes, especially in lower-wind-speed sites
Installed Capital Costs	• Steep reductions in wind turbine prices negotiated over the last 2 years, with some evidence of a simultaneous reduction in balance of plant costs, which are expected to lead to sizable near-term capital cost reductions
Other Possible Advancements (since early 2000s)	• Operation and maintenance: Potential reduction in the cost of O&M for newer wind power projects • Financing: Notwithstanding the impact of the financial crisis, generally improved financing terms over the *longer-term* as the sector and technology have matured • Availability: Potential reduction in losses due to improved turbine/project availability

See following slides for more details…

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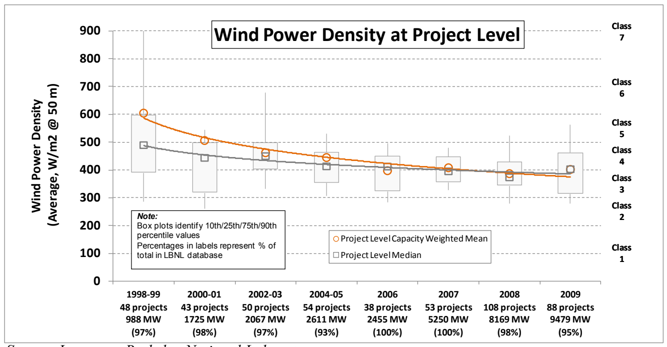
Recent Moderation of CF Increase Driven In Part By Move Towards Lower Wind Speed Sites…

Projects increasingly sited in poorer wind regimes at 50m:

- **1998-2001: Class 4-5 common**
- **2006-2009: Class 3-4 common**

Trend likely driven by transmission/siting limitations and policy influences, as well as improvement in low wind speed technology



Source: Lawrence Berkeley National Laboratory

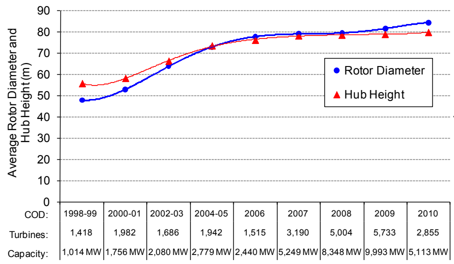
…and Growing Amounts of Wind Energy Curtailment in Some Regions

Wind Curtailment, GWh (percent potential generation)	**2007**	**2008**	**2009**	**2010**
Electricity Reliability Council of Texas	109 (1.2%)	1,417 (8.4%)	3,872 (17.1%)	2,067 (7.7%)
Southwestern Public Service Co.	N/A	0 (0.0%)	0 (0.0%)	0.9 (0.0%)
Public Service Company of Colorado	N/A	2.5 (0.1%)	19.0 (0.6%)	81.5 (2.2%)
Northern States Power Co.	N/A	25.4 (0.8%)	42.4 (1.2%)	42.6 (1.2%)
Midwest ISO, less NSP	N/A	N/A	250 (2.2%)	781 (4.4%)
Bonneville Power Administration	N/A	N/A	N/A	4.6 (0.1%)
Total Across These 6 Areas:	**109 (1.2%)**	**1,445 (6.4%)**	**4,183 (10.4%)**	**2,978 (5.1%)**

Source: U.S. DOE 2011

U.S. fleet-wide capacity factors from 2008-2010 would have been 1-2 percentage points higher absent curtailment
(curtailment largely caused by inadequate transmission and minimum load)

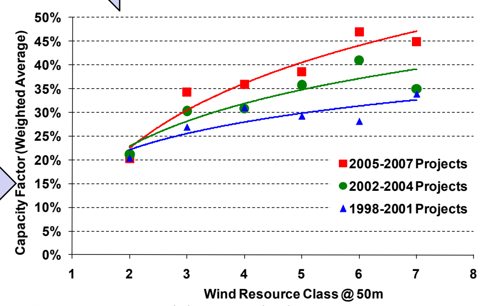
Move to Lower Wind Speed Sites and Increased Curtailment Hide the Very Real Increases in CFs Witnessed in Individual Wind Resource Classes



Source: U.S. DOE 2011

Historical increases in avg. hub height and rotor diameter have been substantial

Leading to sizable increases in avg. capacity factors within specific resource classes



Source: Lawrence Berkeley National Laboratory

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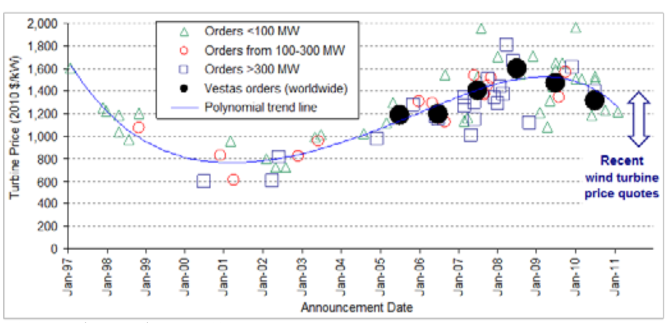
Wind Turbine Prices Have Softened Since Their Highs in 2008



Source: Bolinger and Wiser 2011

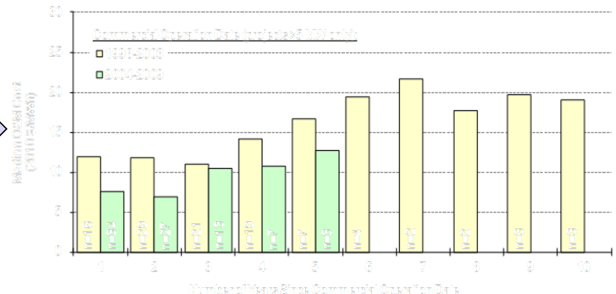
Lag between turbine prices and project costs should lead to substantial project-level installed capital cost reductions by 2012-2013

Turbine price quotes in 2011 for "standard" technology are reportedly <u>as low as</u> $900/kW (Tier 1: ~$1,100-1,250/kW, with average at ~$1,100/kW); higher costs typical for smaller orders, larger rotors/towers, etc.

(also more-favorable terms for buyers and improved technology; balance-of-plant costs also reportedly lower than in recent past)

Some Evidence of Lower O&M Costs, Higher Availability, Improved Financing

O&M costs from limited sample of US wind power projects (U.S. DOE 2011)



GE's reported median availability by model year (Mesh et al. 2011, "GE Wind Turbine Availability)

Figure 1: Americas 1.5SLE/XLE Model Year: Median Lifetime Availability, excluding first 12 weeks of operation

Strength of evidence supporting specific improvements in O&M, availability, and financing somewhat lower than trends in capacity factor and capital cost

Recent "Chatter" Suggests that, As a Result of These Trends, Delivered Wind Energy Costs Have Declined Substantially

BNEF 2011: "The cost of wind generation has been driven to record lows by declines in turbine prices and the cash grant, which eliminates the cost of securing tax equity financing."

"Austin Energy officials say those wind contracts are among the cheapest deals available, when the cost of building power plants is taken into account, and comparable to what the historically volatile natural gas market has been offering recently." *(Statesman.com article)*

"Our contract with NextEra Energy Resources is one of the lowest we've ever seen and results in a savings of nearly 40 percent for our customers," said David Eves, president and CEO of Public Service Company of Colorado. "The addition of this 200-megawatt wind farm demonstrates that renewable energy can compete on an economic basis with more traditional forms of generation fuel, like natural gas, and allows us to meet the state's Renewable Energy Standard at a very reasonable cost to our customers." *(Reuters article)*

Consumers Energy, Michigan: "Lower wind power costs mean $54m saving for Consumers Energy." *(newspaper article)*

Westar, Kansas: Signed more wind contract than needed "...because pricing is so attractive now and to minimize tax risk to our investors" *(Westar Q4 earnings call)*

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Analysis Objective

Estimate Capacity Factors, LCOE, and Developable Land Area By Selecting Representative Assumptions for Turbines Used in U.S. Wind Projects

Installed in 2002-2003	• The low-point of wind project capital costs
Installed in 2009-2010	• The likely peak of wind project capital costs
(To be) Installed in ~2012-13	• When current turbine pricing is likely to more-fully make its way into observed capital costs

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Basic Approach

In each period, account for common actual/expected trends in:

(1) installed capital costs (based on actual/estimated cost)

(2) capacity factors in different wind resource classes (estimated based on available power curves, assuming sea level air density of 1.225 kg/m^3)

For simplicity, in most cases hold constant: O&M costs; financing structure and costs; project/turbine availability and other losses; project life, income taxes, decommissioning, etc.

Estimate LCOE: (1) <u>without</u> PTC or 5-yr MACRS (depreciation assumed to be 12-yr straight line); and (2) <u>with</u> PTC and 5-yr MACRS

Conduct two side analyses: (1) impact of <u>incentive choice</u> between PTC and ITC/Treasury Grant; and (2) impact of possible <u>O&M, financing, and availability</u> trends

Use IEA Task 26 Work-package 1 LCOE model

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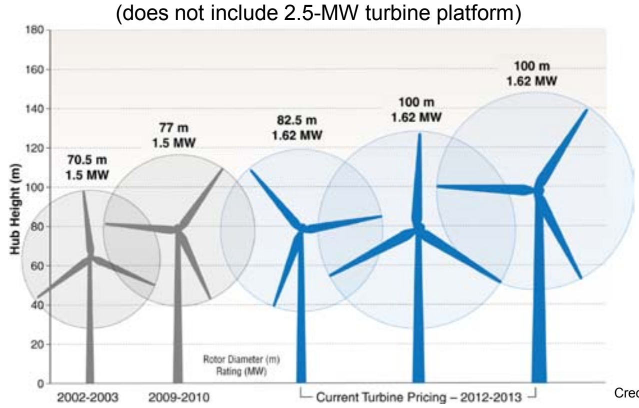
For Analytical Simplicity, Focus on GE Turbine Evolution

Typical GE Turbine Offerings Over Time

(does not include 2.5-MW turbine platform)



Credit: Al Hicks, NREL

GE has been the dominant supplier of turbines to the U.S. market over this timeframe, ensuring that a focus on GE *as an example* of the evolution of cost, performance, and LCOE trends is appropriate

Summary of Core Input Assumptions

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 (HH)	65 m	80 m	80 m	80 m	100 m
Rotor diameter (RD)	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-yr	$60/kW-yr	$60/kW-yr	$60/kW-yr	$60/kW-yr
Losses (availability, array, other)	15%	15%	15%	15%	15%
Financing (nominal)	9%	9%	9%	9%	9%

- Dollar values are all real 2010$
- Financing cost / discount rate reported in nominal terms
- Air density = 1.225 kg/m^3 (sea level wind speed)
- Weibul K Factor = 2 in all scenarios
- 1/7th power law scaling to estimate hub height wind speed
- 20-year assumed project/economic life in all scenarios
- Aggregate income taxes assumed to equal 38.9%

All assumptions intended to reflect representative actual/common conditions; installed costs, operating costs, losses and other assumptions can vary considerably from one project to the next

These turbines are assumed viable in sites up to the respective IEC Class II and Class III reference average annual wind speed. Depending on site specific gust, turbulence, and air densities these turbines in actuality may be reasonably placed in sites with higher average annual wind speeds than applied in this analysis.

Basis For <u>Core</u> Assumptions

Turbine Characteristics (capacity, hub height, rotor diameter)

- Common GE designs for relevant installation years

Installed Capital Cost

- 2002-2003 and 2009-2010: based on actual average costs for installed projects
- 2012-2013: assumes $550/kW drop in turbine/BOP costs since high-point for 80 m HH / 82.5 m RD turbine based on earlier data on turbine cost trends, BNEF (2011), and discussions with wind developers/manufacturers; $250/kW assumed increase for 100 m RD upgrade and additional $175/kW increase for 100 m HH upgrade based on discussions with wind developers/manufacturers; result is an **<u>estimate</u>** of the average installed cost of projects based on current turbine orders; actual project costs will have a large spread around the average, with both lower- and higher-cost projects anticipated

Other Costs and Characteristics

- Operating costs: Assumed to be exclusively denominated in $/kW-yr, though, in practice, some costs may be more-appropriately denominated in $/MWh; all-in operating costs assumed to equal $60/kW-yr in core analysis based on review of available data/literature
- Losses: 15% losses assumed in core analysis based on review of available data/literature, as well as matching actual and estimated project-level capacity factors
- Financing: 9% assumed in core analysis based on review of available data/literature

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Summary of <u>Side-Case</u> Input Assumptions

Incentive Choice	• Assumes that project owners choose between the PTC and ITC/Treasury Grant based only on the face-value of those incentives (i.e., the incentive that minimizes the LCOE with no additional changes and ignoring any ancillary benefits of the ITC/Treasury Grant)
O&M, Financing, Availability	• **O&M:** Cost reduction from <u>$64/kW-yr in 2002-2003 → $57/kW-yr in 2012-2013</u> based on review of available data/literature, including 2010 Wind Technology Market Report, BNEF (2011), etc. • **Financing:** All-in cost of finance decreases as technology matures from <u>10.5% in 2002-2003 → 9% in 2012-2013</u> based on review of available data/literature and discussions with wind developers • **Availability:** Reduction in average project-level losses from <u>16.5% in 2002-2003 → 14% in 2012-2013</u> based only on assumed improvement in availability, itself based on review of limited available data/literature and discussions with wind consultants and developers

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Presentation Outline

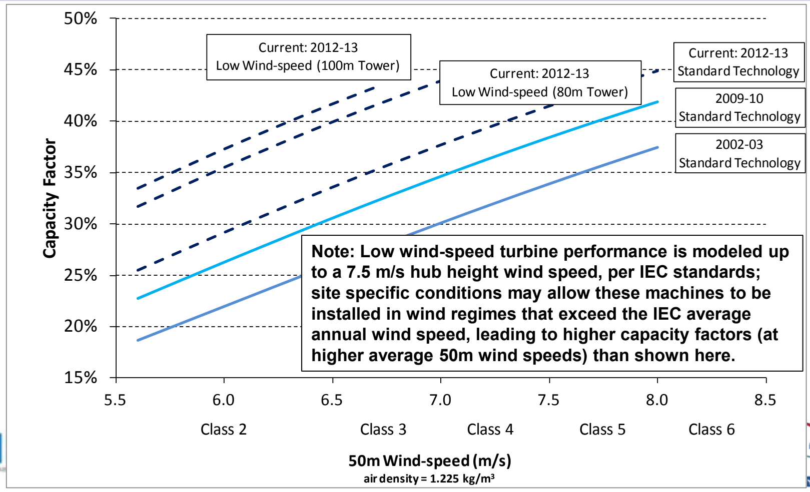
Recent Trends → Analysis Assumptions → **Analytical Results**

Outline of Key Results

- Estimated Capacity Factors in Varying Resource Classes
- Levelized Cost of Energy in Varying Resource Classes
- *Side Analysis:* Impact of Improvements in O&M, Financing, and Availability
- Designing Turbines for Low Wind-Speed Sites: Narrowing the Gap in LCOE
- *Side Analysis:* Impact of ITC/Treasury Grant Option In Lieu of PTC
- Increased Land Area Exceeding Capacity Factor Thresholds
- Increased Land Area Exceeding LCOE Thresholds

Turbine Design Advancement Leads To Enormous Increase in Capacity Factors

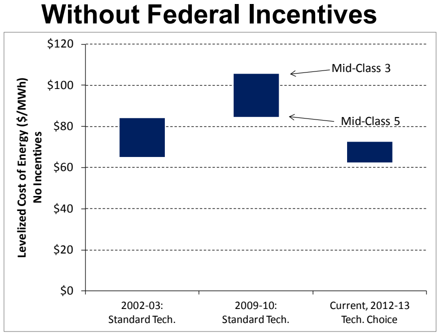
Estimated capacity factor improvement driven by larger rotor swept area in proportion to nameplate capacity, as well as higher hub heights; increase is especially apparent with newest batch of low-wind-speed turbines



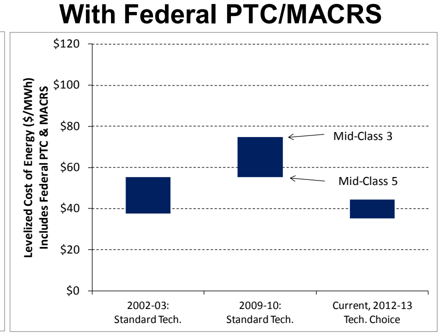
Levelized Cost of Wind Energy Is Estimated To Be at An All-Time Low for 2012-2013

Accounting <u>only</u> for assumed capacity factor and capital cost trends, LCOE increased substantially from 2002-2003 to 2009-2010 because capital cost increases were not fully compensated by CF improvements; estimated LCOE has since dropped below its earlier lows <u>within individual wind resource classes</u> because capital cost increases from 2002-2003 to the present have been more-than offset by CF improvements, yielding a lower LCOE than at any time in the past within individual resource classes

Without Federal Incentives



With Federal PTC/MACRS



Note: "Tech. Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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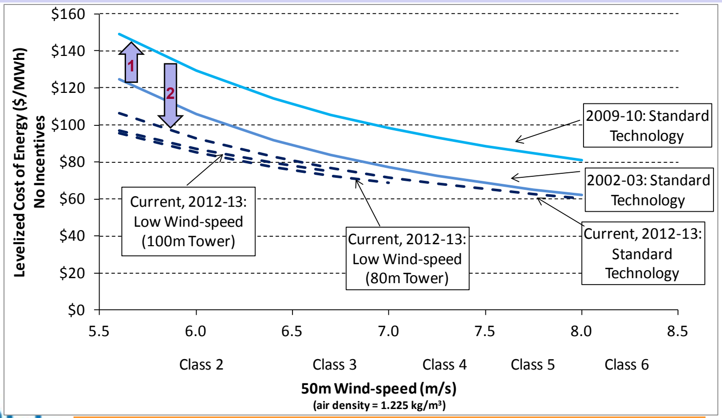
Levelized Cost of Energy in Varying Resource Classes (*without* PTC/MACRS)

Based on current pricing and assumptions: 100m rotor diameter is found to be economically attractive in comparison to 2012-2013 'Standard Technology' where it can be deployed; a wind sheer higher than 1/7th is found to be needed for the 100m tower to be least cost in comparison to the 80m option (with the 100m rotor)



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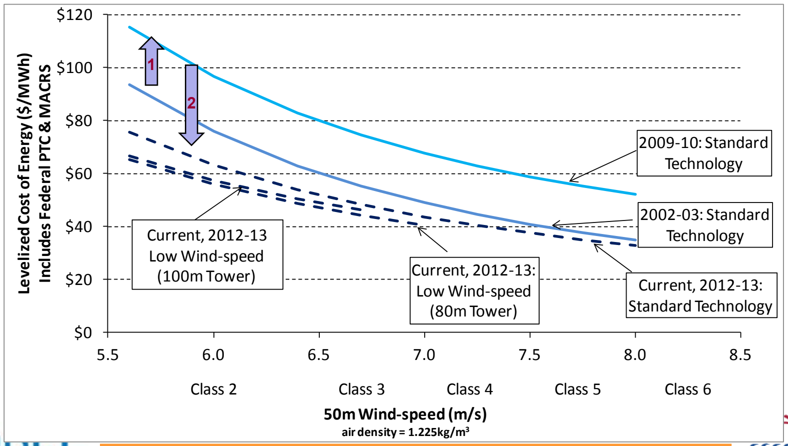
Levelized Cost of Energy in Varying Resource Classes (*with* PTC/MACRS)

With PTC/MACRS and with current turbine pricing and other specific assumptions, the highest wind speed sites evaluated below can support LCOEs as low as ~$33/MWh (real$), while the lower wind speed sites have LCOEs of ~$65/MWh



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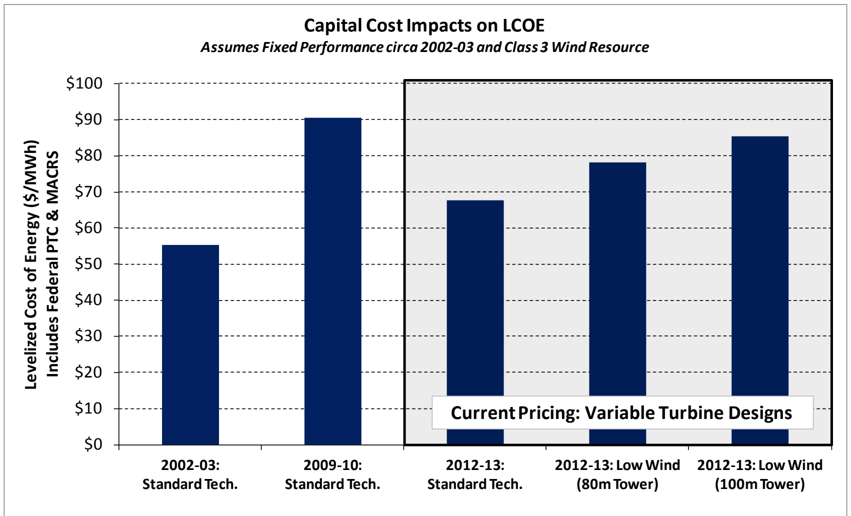
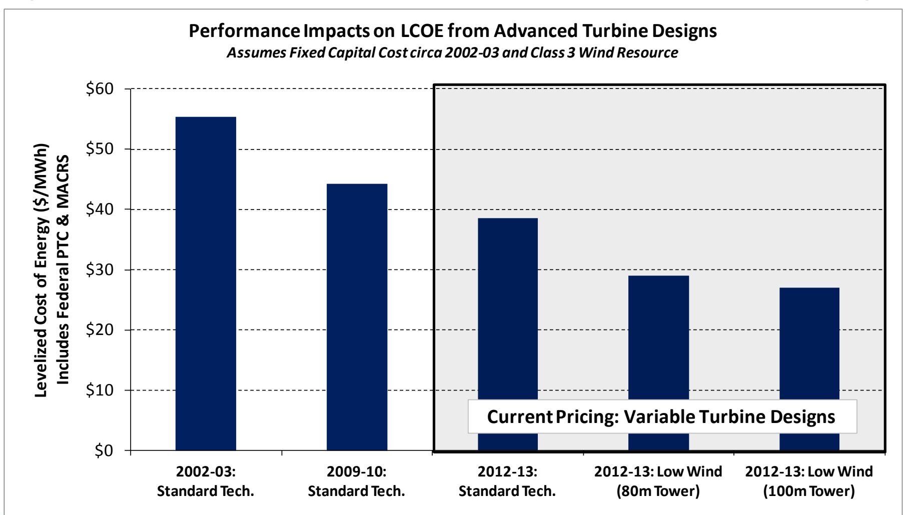
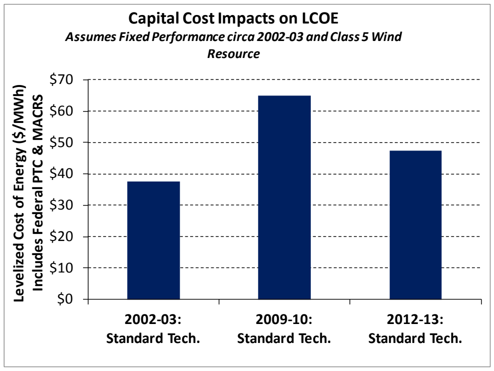
All Else Being Equal, Capital Cost Increases Would Have Led To Much Higher LCOEs
(Mid Class 3 Wind Resource, *with* PTC/MACRS)

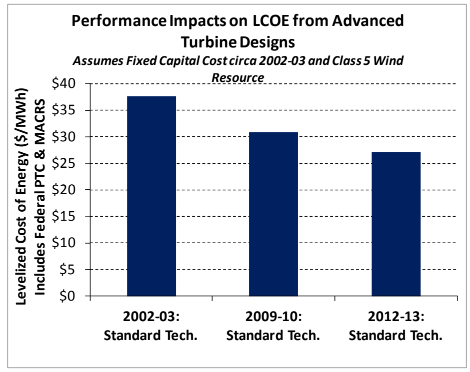


All Else Being Equal, Performance Improvements Would Have Led To Much Lower LCOEs
(Mid Class 3 Wind Resource, *with* PTC/MACRS)



Same Tradeoff Between Capital Cost and Performance Exists in Other Wind Resource Classes
(Mid Class 5 Wind Resource, *with* PTC/MACRS)





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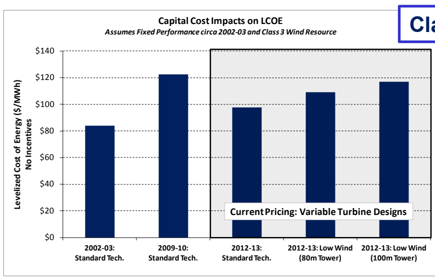
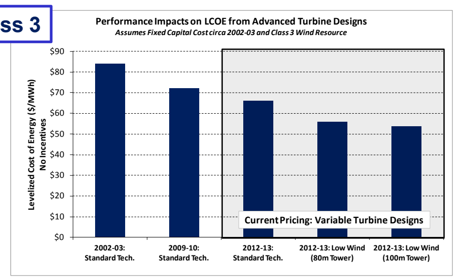
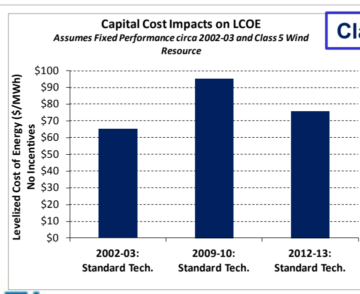
Same Tradeoff Between Capital Cost and Performance Exists *without* PTC/MACRS

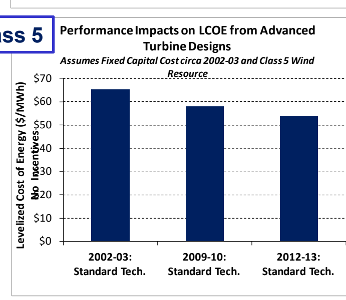
Class 3





Class 5





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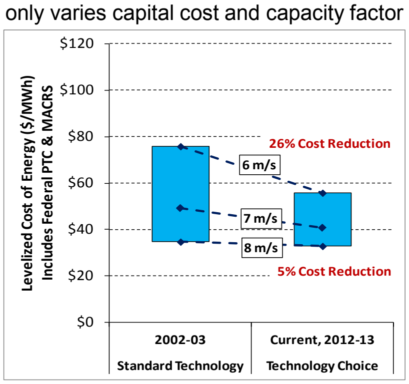
Side Analysis: Impact of Improvements in O&M, Financing, and Availability (*with* PTC/MACRS)

Assumed improvements in O&M costs, financing rates, and availability lead to substantial additional estimated LCOE reductions from 2002-2003 to 2012-2013 in comparison to core analysis that only varies capital cost and capacity factor

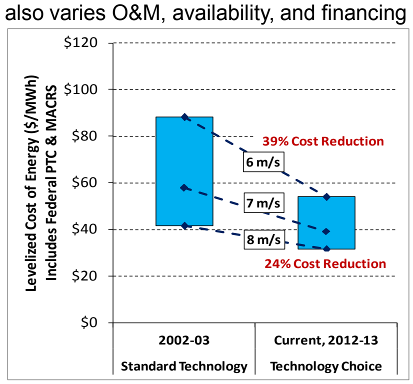
Core Assumptions

only varies capital cost and capacity factor



Side Analysis Assumptions

also varies O&M, availability, and financing



Note: "Technology Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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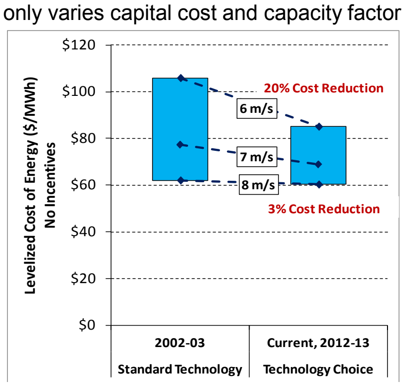
Side Analysis: Impact of Improvements in O&M, Financing, and Availability (*without* PTC/MACRS)

Assumed improvements in O&M costs, financing rates, and availability lead to substantial additional estimated LCOE reductions from 2002-2003 to 2012-2013 in comparison to core analysis that only varies capital cost and capacity factor

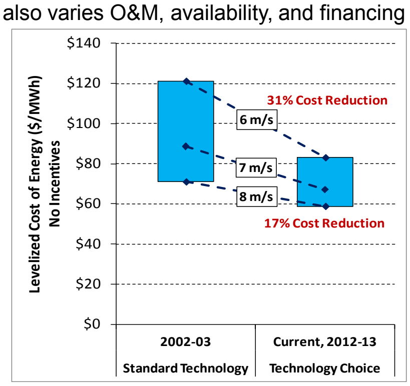
Core Assumptions

only varies capital cost and capacity factor



Side Analysis Assumptions

also varies O&M, availability, and financing



Note: "Technology Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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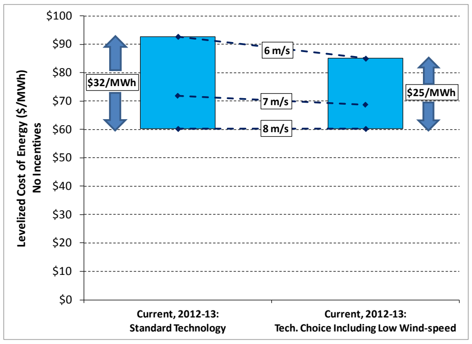
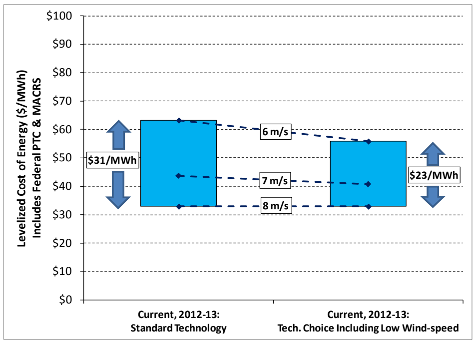
Designing Turbines for Low Wind-Speed Sites: Narrowing the Gap in LCOE

The proliferation of turbines designed for lower wind speeds has narrowed the gap between the LCOE of high- and low- wind speed sites, increasing the economic attractiveness of developing wind projects in lower wind speed areas

Without Federal Incentives



With Federal PTC/MACRS



Notes: Does not consider Treasury Grant program / 30% ITC (see later results); "Tech. Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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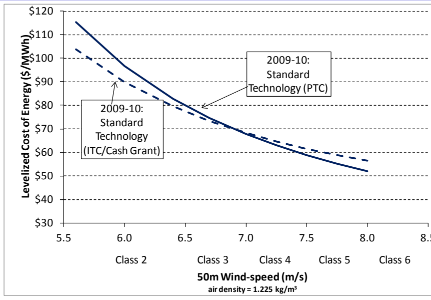
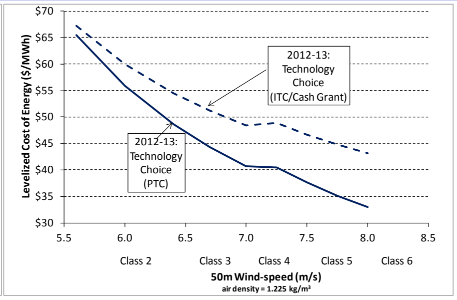
Side Analysis: Incentive Choice Has Also Impacted the Economics of Low Wind Speed Sites

- 30% ITC/Grant applied to capital cost is relatively more lucrative than PTC on "face-value" basis when a project has a low capacity factor and high costs → see results for 2009-2010 'Standard Technology' in chart on left
- Current turbines / pricing have higher assumed capacity factors and lower costs, making PTC the better choice in virtually all developable wind regimes on "face value" basis → see results for 2012-2013 turbines in chart on right





Note: Results ignore benefits of ITC/Treasury grant beyond direct face value;
"Technology Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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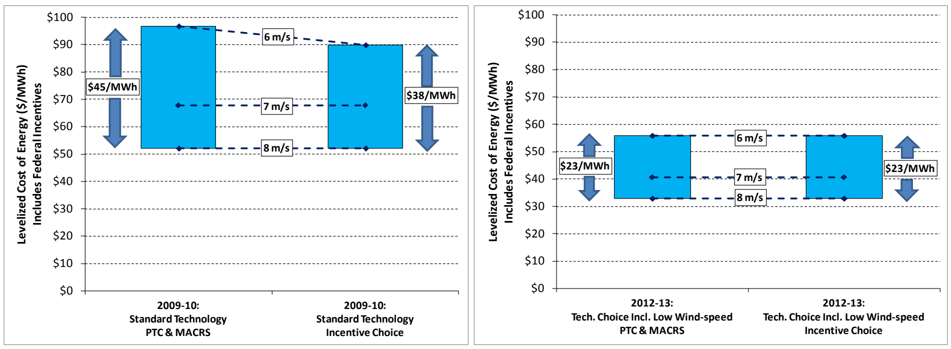
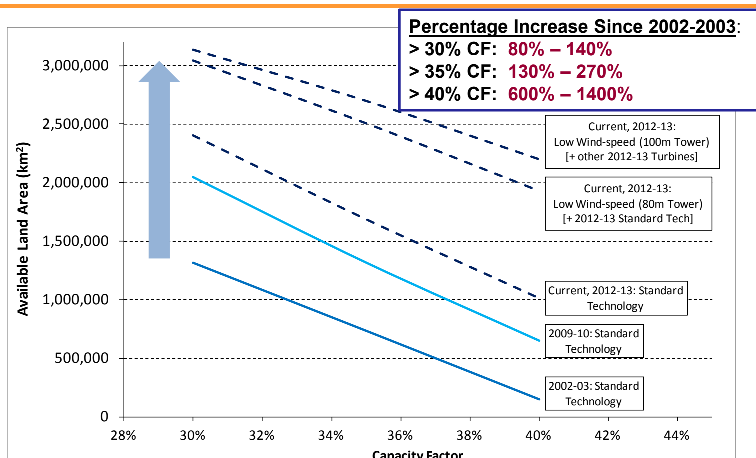
Result Was Narrowing in LCOE Between High & Low Wind Sites in 2009-2010, Not in 2012-2013

ITC/Grant improved the economics of low wind speed sites in 2009-2010; estimated lower capital costs and improved capacity factors result in face value of PTC > ITC/Grant in 2012-2013 even in low wind speed sites
(ancillary benefits of ITC/Grant may still outweigh loss in face value in such sites)



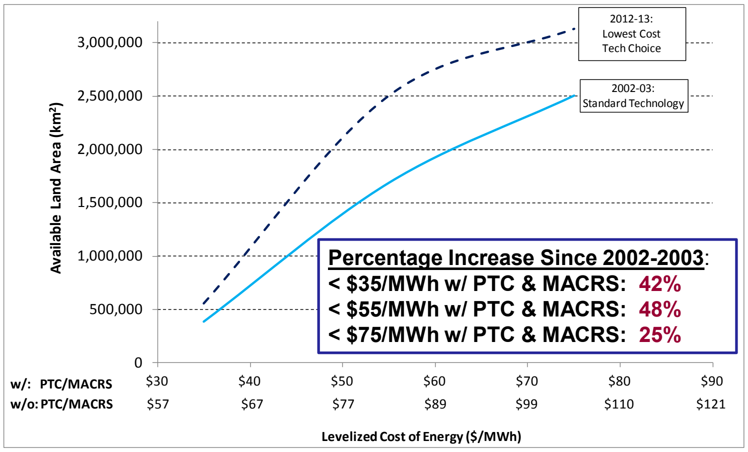
Note: "Tech. Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

Land Area Exceeding Capacity Factor Thresholds Has Increased Dramatically



Notes: Wind speed data come from the 50 m long-term assessments produced by AWS Truepower, MN Dept of Commerce, Iowa State Energy Center, Alternative Energy Institute (Texas), and NREL. Alabama, Louisiana, Mississippi, and Florida were not covered by any of these datasets. Standard wind resource exclusions were applied, as documented on the Wind Powering America website. Low wind-speed turbines are assumed to be utilized in sites up to 7.5 m/s sea level equivalent average annual wind-speed, per IEC standards. Site specific conditions may allow these machines to be placed in higher average annual wind-speed sites, which would further increase the percentage increase in available land area beyond what is estimated here.

Land Area Exceeding LCOE Thresholds Has Also Increased Substantially



Notes: Increase in land area meeting a LCOE threshold is lower than the increase from a CF threshold because increased capital cost trends impact LCOE estimates, but not CF; "Tech. Choice" assumes that IEC Class III machines are only available for sites up to 7.5 m/s average wind speed at hub height (sea level air density)

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Conclusions

- Economic attractiveness of wind projects in recent past was reduced due to increased capital cost, move toward lower wind speed sites, and lower electricity prices
- Examination of historical trends in capital costs and capacity factors, individually, gives an incomplete picture of technology advancement as well as historical & current developments
- Recent declines in turbine prices & improved technology have reduced the estimated LCOE of wind; LCOE for projects being planned today in fixed resource areas is estimated to be at an all-time low
- Considering plausible assumptions for not only capital cost and capacity factor, but also O&M, financing & availability, the **LCOE for 2012-2013 projects is estimated to be as much as ~24% and ~39% lower than the previous low in 2002-2003** in 8 m/s and 6 m/s (at 50 m) resource areas, respectively (with the PTC/MACRS); **when only considering capital cost and capacity factor, the reduction is ~5% and ~26%**

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Conclusions

- Technology advancement for lower wind speeds has narrowed the gap in LCOE between lower and higher wind speed sites; choice of 30% ITC/Treasury Grant may have further encouraged development in lower wind speed sites, especially in 2009-2010
- The amount of land area meeting or exceeding certain capacity factor and LCOE thresholds has substantially increased as a result of these technology improvements → helps alleviate to a degree transmission and siting barriers
- Technology advancement & learning still applies to onshore wind, despite its relative maturity, but all modes of technical advancement must be considered rather than emphasizing individual parameters
- Despite these recent and impressive technological advancements, three counter-veiling factors may intervene to raise LCOE:
  - potential for increased pricing if demand for wind turbines begins to catch up with supply, or if other exogenous influences are triggered (e.g., higher commodities and/or labor costs)
  - potential continued move towards lower wind speed sites as a result of severe transmission/siting limitations
  - potential near-term loss of federal PTC/ITC/Treasury Grant

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Unpacking the Drivers Behind Recent U.S. Wind Project Installed Cost and Performance Trends

Unpacking the Drivers Behind Recent U.S. Wind Project Installed Cost and Performance Trends

Ryan H. Wiser
Lawrence Berkeley National Laboratory

IEA Cost of Wind Energy Workshop

Denver, Colorado
March 29, 2011

This analysis was funded by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy, Wind and Hydropower Technologies Program

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Understanding Trends in Wind Project Costs

This portion of the presentation has been published. Please see the final report and presentation at:

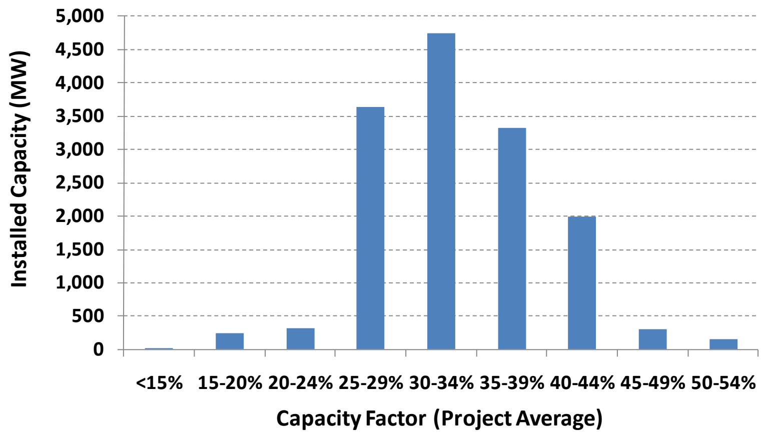
http://eetd.lbl.gov/ea/emp/re-pubs.html

Understanding Trends in Wind Project Performance

- Preliminary Analysis -

Wind Project Capacity Factors (CF) in the United States Vary Substantially By Project

Focusing on **14,722 megawatts (MW)** installed from 1998–2007, capacity-weighted fleet-average CFs from 1999–2008 equaled **33.7%**



14,722 MW equals 95% of all wind capacity added over this time frame

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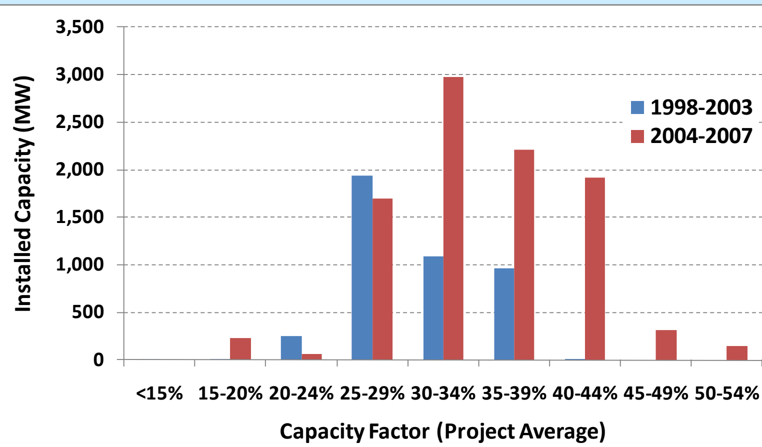
Average Capacity Factors Have Increased Over Time, by Project Vintage

2% of projects installed from 1998–2003 had average CFs **> 40%**
25% of projects installed from 2004–2007 had average CFs **> 40%**



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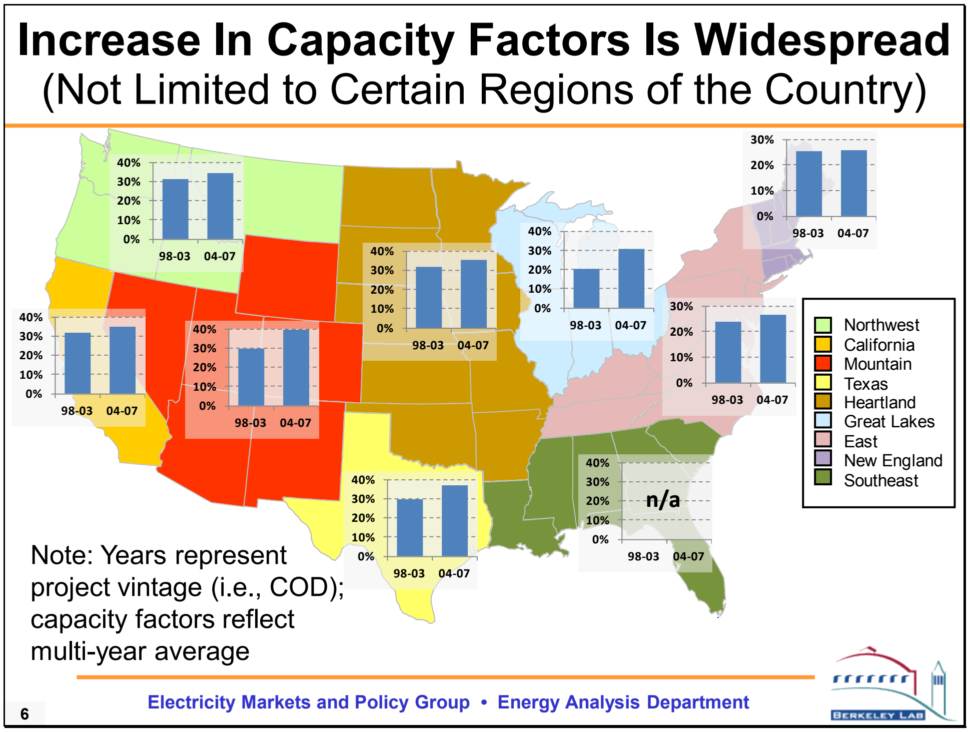

Increase In Capacity Factors Is Widespread
(Not Limited to Certain Regions of the Country)
98-03
04-07
n/a
Northwest
California
Mountain
Texas
Heartland
Great Lakes
East
New England
Southeast
Note: Years represent project vintage (i.e., COD); capacity factors reflect multi-year average
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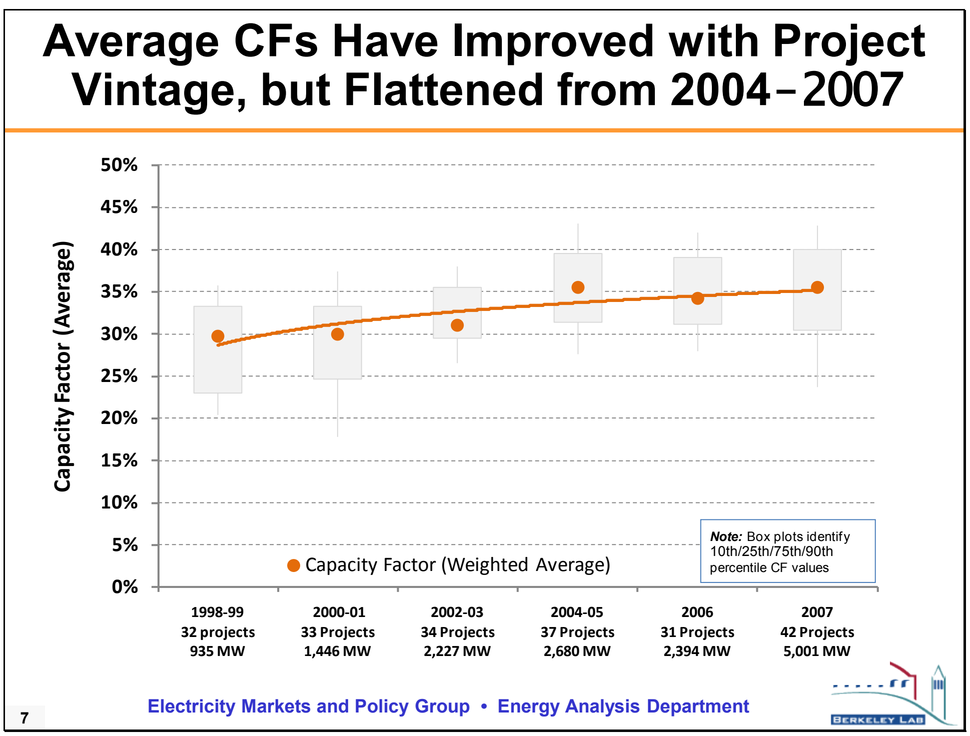

Average CFs Have Improved with Project Vintage, but Flattened from 2004–2007
Capacity Factor (Average)
Capacity Factor (Weighted Average)
Note: Box plots identify 10th/25th/75th/90th percentile CF values
1998-99 32 projects 935 MW
2000-01 33 Projects 1,446 MW
2002-03 34 Projects 2,227 MW
2004-05 37 Projects 2,680 MW
2006 31 Projects 2,394 MW
2007 42 Projects 5,001 MW
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Possible Drivers of Project Performance

- **Project siting:** Projects located in stronger wind regimes, as well as better micro-siting, may increase capacity factors
- **Higher hub heights:** Given wind shear, taller towers will access better wind speeds
- **Larger rotor diameters (relative to rated capacity):** Longer blades will increase energy capture
- **More-efficient turbine designs:** Evolutionary gains in turbine and blade design/electronics may increase energy capture
- **Improved availability:** Possible improvement in project-level availabilities over time
- **Annual wind resource variation:** Wind resource quality can vary from one year to the next, nationally and regionally.
- **Output curtailment:** Physical or financial curtailment of output due to transmission limitations and minimum generation conditions

Objective: Evaluate a Subset of These Drivers to Better Understand Overall Trends

- For now, focus only on projects built from 1998 – 2007 (older projects not representative, and have data issues)
- Determine turbine coordinates, hub height, and rotor diameter using Federal Aviation Administration (FAA) database and other sources
- Correlate turbine/project coordinates to respective average *estimated* wind resource using available wind maps
- Collect and organize project performance data from the Federal Energy Regulatory Commission (FERC), Energy Information Administration (EIA), and other sources for data years 1999 – 2008
- Document trends in project performance nationally, by region, by turbine type, by wind resource class, etc.
- Analyze resulting data (i.e., average wind resource, hub height, and rotor diameter) to discern relative impact on capacity factors

Current Data Sample: Projects Installed from 1998–2007, with Turbines >200 kilowatts (kW)

Project Sample Description	Nameplate Capacity
Total sample of *possible* projects	15,537 megawatts (MW)
Projects for which we have rotor diameter, hub height, and location/resource	15,268 MW
Projects for which we have above data and project-level capacity factor *(for at least one year)*	**14,722 MW** **95%** of possible sample

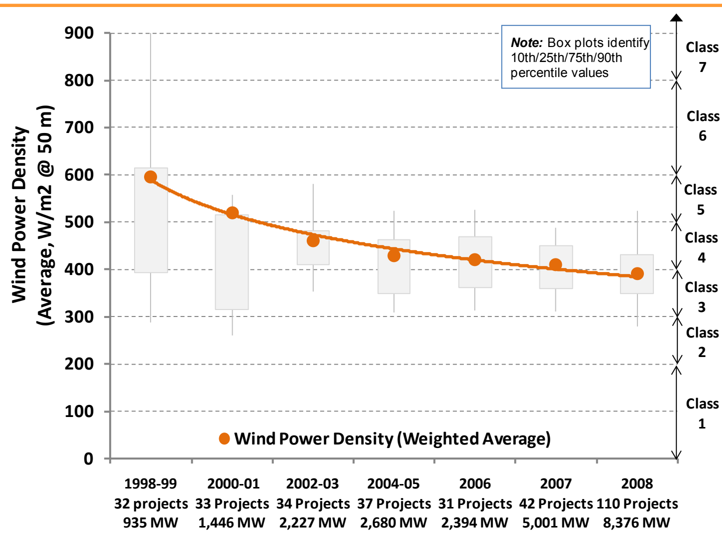
Rotor diameter, hub height, and location/modeled resource data have also been collected for 8,376 MW built in 2008; currently collecting data for 2009–2010

Results: CFs Increased Despite Significant Decrease in Average Wind Resource at 50 Meters (m)

Projects increasingly sited in poorer wind regimes at 50 m:

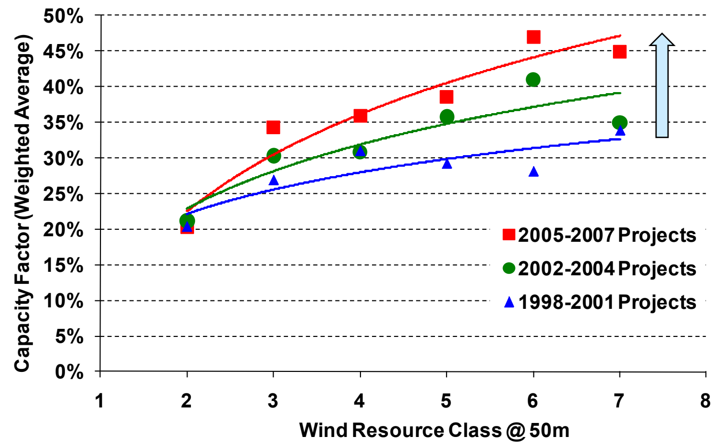
High Class 5 in 1998–1999

High Class 3 in 2008



This Must Be a Story of Technical Change: Hub Height, Rotor Diameter, Efficiency, Etc.

Capacity factors have increased with project vintage within fixed estimated wind resource regimes at 50 m



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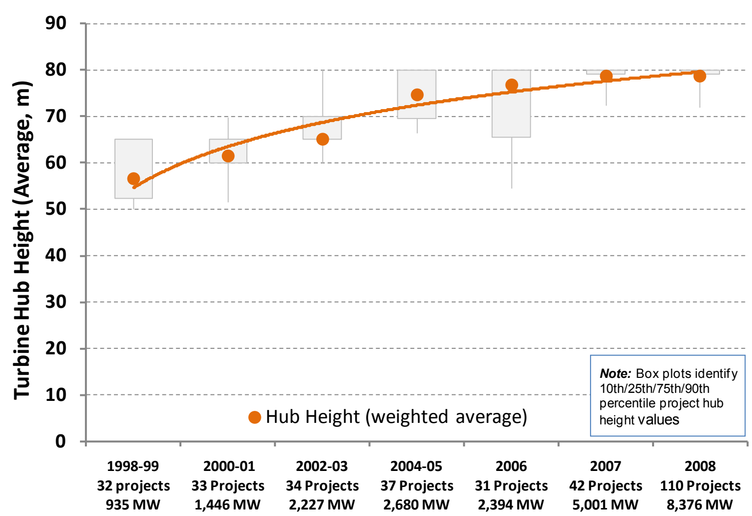
Average Hub Heights (HH) Have Experienced a Dramatic Increase



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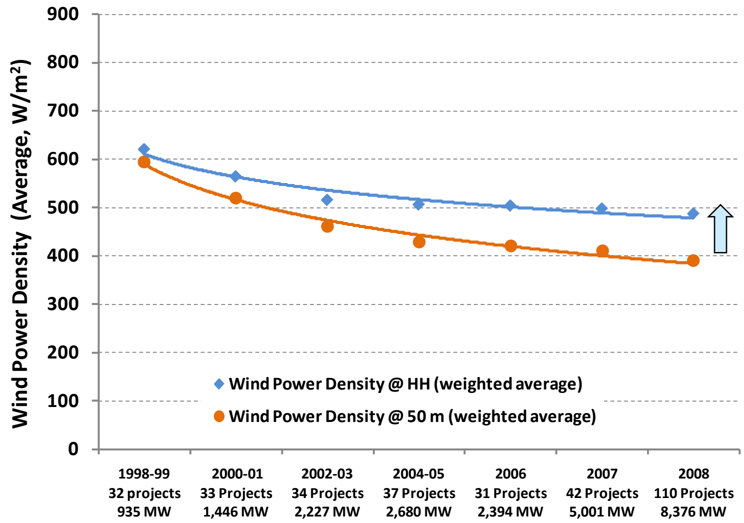
But…Assuming 1/7th Power Law, Average Wind Resource at HH Has Still Declined



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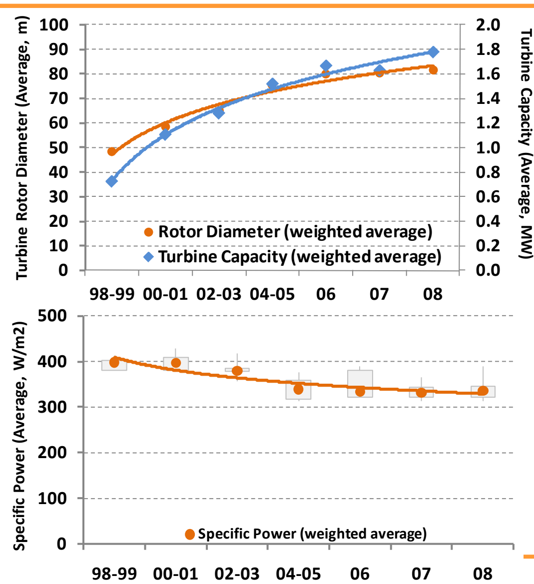
Rotor Diameter Has Increased; Specific Power (W/m² Swept Area) Has Decreased



- Larger rotors optimized for lower wind speeds
- Rotor swept area has increased more rapidly than turbine capacity, leading to **reductions** in average **specific power** (W/m²)
- Turbines with lower specific power will tend to have higher CFs (not greater kWh/m²)

1

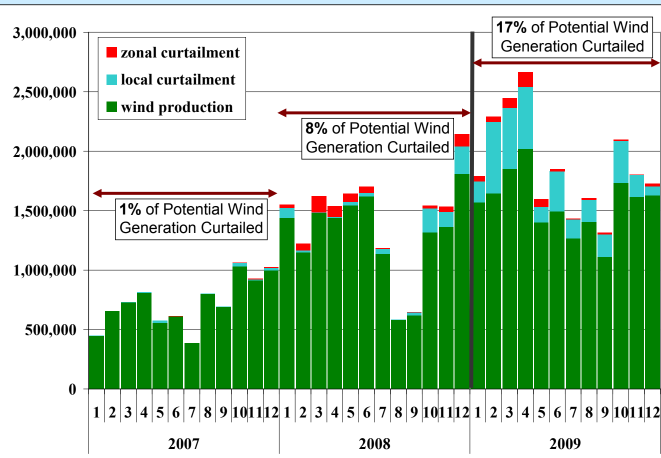
More Efficient Turbine and Blade Designs, Electronics, and Project Availabilities

In combination, the following factors (among others) may have contributed to an increase in CFs over time:

- Variable speed technology
- Improved blade design
  - More aerodynamically efficient airfoils
  - Lower soiling losses
- Better control systems and algorithms
- Better understanding of wake effects
- Drive-train efficiency improvements
- Higher project-level availabilities

Curtailment Needs to Be Considered As One Factor That Might Drive CFs Lower

Curtailment has been greatest in Texas, and increased substantially in 2009. Our performance data extends through 2008, so curtailment is less of an issue in the present analysis.



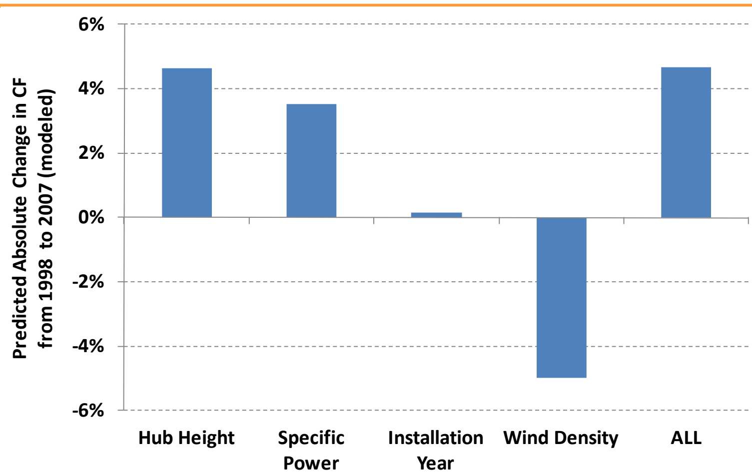
Regression Analysis Helps To Piece Together the Story

Regression analysis shows **relative** influence of: (1) wind power density at 50 m; (2) hub height; (3) specific power; (4) installation year (COD) to account for efficiency/availability; (4) Texas/state dummy variables to account for curtailment, errors in state wind maps, etc.

$$\ln(CF_{avg}) = \beta_0 + \beta_1 \cdot \ln(WPD) + \beta_2 \cdot \ln\left(\left(\frac{HH}{50}\right)^{3/7}\right) + \beta_3 \cdot \ln\left(\frac{1}{SP}\right) + \beta_4 \cdot COD + \sum_i \beta_{i+4} \cdot State_i + \varepsilon$$

	$\ln(WPD)$	$\ln\left(\left(\frac{HH}{50}\right)^{3/7}\right)$	$\ln\left(\frac{1}{SP}\right)$	COD	Texas
Beta	0.527	0.989	0.584	0.014	0.075
Stand. Error	0.066	0.324	0.194	0.008	0.033
P-value	0.000	0.003	0.003	0.153	0.023

Decoding the Influence of the Variables: Graphic Presentation of Regression Results



Actual data show absolute increase in CF of 5.8% from 1998–1999 to 2007 projects; regression analysis estimates 4.6%