Understanding Wind Turbine Price Trends in the U.S. Over the Past Decade

Mark Bolinger and Ryan Wiser
Lawrence Berkeley National Laboratory

Pre-print of article submitted to *Energy Policy*

Abstract: On a $-per-kW basis, wind turbine prices in the U.S. have declined by nearly one-third on average since 2008, after having previously doubled over the period from 2002 through 2008. These two substantial and opposing trends over the past decade – and particularly the earlier price doubling – run counter to the smooth, gradually declining cost trajectories predicted by standard learning curve theory. Taking a bottom-up approach, we examine seven possible drivers of wind turbine prices in the U.S., with the goal of estimating the degree to which each contributed to the doubling in turbine prices from 2002 through 2008, as well as the subsequent decline in prices through 2010. In aggregate, these seven drivers – which include changes in labor costs, warranty provisions, manufacturer profitability, turbine scaling, raw materials prices, energy prices, and foreign exchange rates – explain from 70% to 90% (depending on the year) of empirically observed wind turbine price movements in the U.S. through 2010. Turbine scaling is found to have been the largest single contributor to the price doubling through 2008, although the incremental cost of scaling has been justified by greater energy capture, resulting in a lower cost of wind generation.

Acknowledgments

The work described in this article was funded by the U.S. Department of Energy's Wind & Water Power Program, within the Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

Disclaimer

1. Introduction

A considerable literature has developed using learning curve theory to explore how increases in cumulative wind power capacity (and other factors) have historically driven down wind energy costs (for a brief survey of the peer-reviewed literature, see Wiser et al. 2011a). The principal parameter calculated by these studies is the learning rate: for every doubling in cumulative production or installation, the learning rate specifies the associated percentage reduction in costs. Learning rates based on historical data are then often used to forecast future cost developments. As an example, Wiser and Bolinger (2011) calculate a learning rate of 14.4% for the installed cost of wind power projects in the United States during the period between 1982 and 2004, meaning that for each doubling in cumulative installed wind capacity worldwide over this period, installed wind project costs in the U.S. fell by 14.4% on average.

These historical cost reductions, in concert with governmental policies and other drivers, helped to fuel rapid growth in the industry, both domestically and abroad, starting around the turn of the century (Figure 1). In fact, although wind power technology has been commercially available for decades, more than 90% of all wind power capacity both in the US and worldwide has been installed in just the last 10 years. Over this period, global installed wind power capacity more-than-doubled in the four years from 2002 through 2005, and then again in the three years from 2006 through 2008; it is currently on track to double yet again by late 2011.

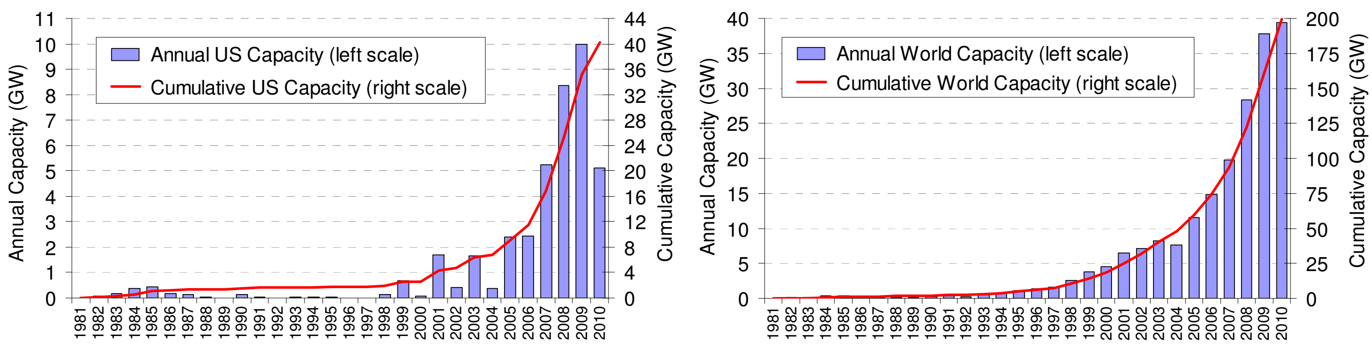

Figure 1. US and Global Installed Wind Power Capacity: 1981-2010

Consistent with standard learning curve theory, the most-recent doubling expected by late 2011 has, in fact, been accompanied by significant cost reductions: as demonstrated later in Section 2, wind turbine prices in the U.S. have fallen somewhere on the order of 20%-33% on average since 2008. By some accounts, these turbine price declines, in combination with improvements in turbine design and performance, will result in a lower cost of wind electricity among projects currently being built than has ever before been possible (Wiser et al. 2011b).

It is important to recognize, however, that the substantial turbine price declines since 2008 started from elevated levels that, themselves, were not consistent with a simple understanding of standard learning curve theory. Rather than the nearly 30% decline in wind project costs that learning curve theory would have expected from 2002 through 2008 as a result of the two doublings in global installed capacity over this period, reported wind project costs in the U.S. actually *increased* by more than 50% percent over this period (Wiser and Bolinger 2011), due primarily to a *doubling* in wind turbine prices. This doubling in wind turbine prices through 2008 marks a substantial divergence from the simple application of learning curves to cumulative wind power installations.

This divergence has important implications for the wind industry, policymakers, research and development (R&D) program managers, and energy analysts. With the wind industry only recently becoming a serious contributor to the power sector in the U.S. and globally, it must take care that unexpected cost inflation does not price wind out of the market, leading to demand destruction. Policymakers who count on wind to provide a growing share of the world's electricity needs – and who enact policies aimed to achieve that goal – want reassurances that wind can meet this challenge in a cost-effective manner (and perhaps even eventually wean itself off of direct public policy support altogether). R&D managers need to understand past cost trends in order to target future research most effectively. Finally, energy analysts who have heretofore placed some faith in the simple application of learning curves to project future technology costs must potentially reevaluate their beliefs and develop a more nuanced understanding of the drivers of wind (and other forms of) power costs.

Common to all four sets of stakeholders is a growing need to understand what specific factors – if not learning effects – have been driving recent wind power cost trends, and in particular the doubling in wind turbine prices from 2002 through 2008. This article seeks to contribute to such an understanding, with a specific focus on the cost of wind turbines deployed onshore in the United States. In doing so, it builds on the work of other studies that have begun to develop a deeper understanding of historical renewable energy cost drivers beyond simple, traditional concepts of learning (see, e.g., Ferioli et al. 2009, Nemet 2006; Papineau 2006, Yu et al. 2011),[1] as well as those that have examined in some detail other causal influences to wind power costs, both on- and offshore (e.g., Berry 2009, Blanco 2009, Bolinger and Wiser 2009, BWEA & Garrad Hassan 2009, Carbon Trust 2008, Dinica 2011, Ernst & Young 2009, Greenacre et al. 2010, Milborrow 2008, Willow & Valpy 2011).[2]

To set the stage, Section 2 documents the increase in onshore wind turbine prices from 2002 through 2008 and the subsequent decline through 2010 using empirical data from the United States, as well as data provided by Vestas – the second-largest wind turbine supplier in the US market over this period. Section 3 examines seven different drivers that have been implicated to varying degrees in the run-up in wind turbine prices through 2008. Based on the analysis in Section 3, Section 4 presents the approximate degree to which each of these seven drivers, both individually and in aggregate, is found to have contributed to the overall movement in wind

[1] This article, however, employs a looser and more-generalized interpretation of technology learning than much of this existing literature, and also focuses on a shorter time frame. For example, whereas Nemet (2006) attributes historical reductions in the cost of photovoltaics over a 26-year period among seven cost drivers, and then estimates the extent to which each of those drivers was influenced by technology learning, this article focuses primarily on just a seven-year period of *increasing* turbine prices, and only loosely separates price drivers into those that could possibly be influenced by technology learning (i.e., labeled herein as endogenous drivers) and those that likely are not (i.e., exogenous drivers). The fact that turbine prices rose rather than fell over the seven years of interest mitigates the need for a more rigorous attribution of learning vs. non-learning effects – i.e., rising prices alone are a clear enough indicator that influences other than technology learning were at work during this period.
[2] Related literature has also sought to explore the historical cost drivers for coal (e.g., McNerney et al. 2011) and nuclear (e.g., Koomey and Hultman 2007).

turbine prices over this period. Section 5 concludes by drawing insights from the analysis, and using them to look ahead to 2011 and beyond.

Before proceeding, we emphasize that this article focuses solely on wind turbine prices, rather than on the total installed cost of wind projects (which also includes balance of plant costs) or on the levelized cost of wind generation (which is further affected by financing terms, operating and maintenance expenses, and the amount of electricity generated). For the purposes of this article, a wind turbine's price is assumed to cover the tower, nacelle (and all of the components therein, such as the generator), and a rotor with blades, all delivered to the project site – foundations and other balance of plant work are not considered to be included in a turbine's price. In general, wind turbine prices account for roughly 60%-70% of total installed project costs, and a slightly lower percentage of the levelized cost of wind generation (due to the latter also reflecting O&M and financing costs). Though it is ultimately the levelized cost of generation that is the most important of these three cost metrics, understanding trends in wind turbine pricing is a critical element to understanding trends in the levelized cost of wind generation.

2. Wind Turbine Price Trends in the United States

Berkeley Lab has gathered price data on 81 U.S. wind turbine transactions totaling 23,850 MW announced from 1997 through early 2011. Because of limitations in the data sources – most of which are press releases and news reports – the precise content of many of the individual turbine transactions is not known, though most transactions likely include only the turbines and towers delivered to the project site, as well as limited warranty and service agreements. Balance of plant ("BOP") construction, including foundation construction and turbine erection, is most often handled separately by engineering, procurement, and construction ("EPC") contractors (Bloomberg NEF 2011a, Fowler 2008).[3] Nevertheless, because of this uncertainty and the fact that our data sources are diverse, emphasis should be placed on overall trends in the data, rather than on individual data points.

Figure 2 depicts these reported wind turbine transaction prices (along with the associated trend line), broken out by the size of the transaction (in MW). Because visibility surrounding wind turbine transactions has declined in recent years,[4] Figure 2 also presents a range of reported

[3] For example, Vestas categorizes its turbine orders as "supply only" (which includes only delivery and commissioning), "supply-and-installation" (which also includes turbine erection), or "EPC/Turnkey" (which also includes all other BOP and civil construction). Globally, half of all turbine orders placed with Vestas in 2010 were of the "supply-only" variety (Vestas 2011b), while in the U.S., the vast majority of Vestas turbine orders are reportedly for "supply-only" (Villadsen 2011). Data on the market share of EPC contractors from Bloomberg NEF (2011a) suggest that other wind turbine manufacturers are in a similar position – i.e., turbine erection and other BOP work most often falls outside of the turbine supply agreement.

[4] For example, the sample includes just 10 transactions summing to 907 MW announced in 2010 and early 2011 – i.e., just 14% of the 6,280 MW of new turbine orders reported over this period by AWEA (2011). In addition to less transparency surrounding new orders, there have also been fewer orders overall in recent years, partly a function of reduced demand for wind turbines since the financial crisis of 2008/2009. Prior to the crisis, and heading into the peak of the wind turbine market (in terms of demand and pricing), many of the larger U.S. wind project developers entered into multi-year "frame agreements" with turbine manufacturers as a way to secure their anticipated turbine needs for the foreseeable future at a known price. In the wake of the financial crisis, demand for wind power in the

pricing for transactions signed in 2010 and so far in 2011, sourced from Bloomberg NEF (2011b) as well as wind industry contacts. Finally, serving only as a quality check on our post-2004 transaction sample, Figure 2 includes average turbine prices reported by Vestas for the years 2005 through 2010 (Vestas 2011b, 2011c, 2011d) and converted into 2010 U.S. dollars.[5]

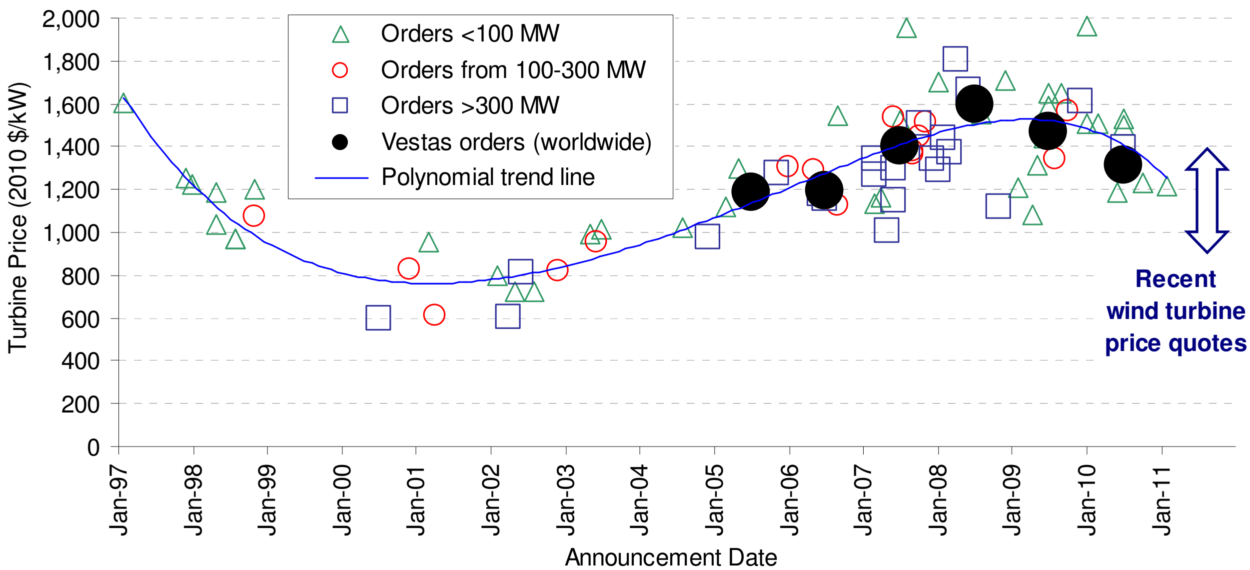

Figure 2. Wind Turbine Prices in the United States

After hitting a low of roughly $750/kW from 2000 to 2002, average wind turbine prices *doubled* through 2008, rising to an average of roughly $1,500/kW. Wind turbine prices have since declined substantially, with price quotes for transactions executed in 2010 and to date in 2011 ranging from $900-$1,400/kW. These figures suggest price declines of as much as 33% or more since late 2008, with an average decline closer to perhaps 20% for orders announced in 2010 (as opposed to in 2011). As of July 2011, BNEF (2011c) was reporting U.S. transactions averaging $1,100/kW, though actual prices are highly dependent on the selected turbine design, with technology designed for lower wind speed sites (i.e., deploying higher hub heights and larger rotor diameters) coming in at higher pricing points.

U.S. diminished, leaving many developers holding more turbines than they could reasonably deploy, and therefore reducing demand for new turbine orders.

[5] The prices reported by Vestas are derived from order intake (in billion Euros) divided by MW ordered, and represent "averages for all markets, all contract types, all project sizes and all products." As such, unlike the other data points in Figure 2, the Vestas averages are not exclusively U.S.-specific, likely include a higher prevalence of "supply-and-install" and "EPC/Turnkey" contracts, and also presumably include some offshore wind turbines. That said, the fact that the Vestas prices match up quite well with the polynomial trend line from the Berkeley Lab turbine transaction sample suggests that these factors may not unduly influence the averages (e.g., offshore wind still accounts for a relatively small portion of Vestas' turbine sales). Regardless, the Vestas prices are only included here as a benchmarking exercise – i.e., to confirm the trends revealed through our empirical transaction sample – and are not used in any of the later analysis (although given that much of the later analysis relies on *other* types of data from Vestas, it is comforting to see the general agreement between the Vestas reported turbine prices and the empirical turbine prices used in the analysis).

Though other generation technologies experienced similar cost trends over this period,[6] these large swings in wind turbine prices merit an explanation. Moreover, the fact that the cumulative global installed capacity of wind power doubled *twice* during the period of rising prices suggests that we must look somewhere other than traditional learning curve theory for this explanation.

3. Wind Turbine Price Drivers

Taking a bottom-up approach, this section examines seven potential drivers of wind turbine prices in the United States, with the goal of estimating the degree to which each contributed to the increase in turbine prices from 2002 through 2008, as well as the subsequent decline in prices through 2010; continued turbine price reductions experienced in the first half of 2011 are addressed to only a limited extent, in Section 5.[7] The first four of these drivers can be considered, to at least some degree, endogenous influences that should benefit from learning: these include labor costs (which are impacted by labor rates and quantities, the latter of which is endogenous), warranty provisions (which reflect technology performance and reliability, and are most often capitalized in turbine prices), turbine manufacturer profitability (which can impact turbine prices independently of costs), and turbine design (for the purpose of this analysis, principally manifested through increased turbine size). The other three drivers analyzed in this study can be considered largely exogenous in that they can impact wind turbine costs but are not readily affected by learning in the wind industry, and include changes in the commodity price of raw materials and energy inputs to manufacturing processes, as well as movements in foreign exchange rates.

Figure 3 shows the cumulative change (since 2001) in each of these seven potential turbine price drivers (individual lines), as well as all seven drivers combined (shaded columns), all expressed in terms of 2010 $ per kW. The next seven sections – Sections 3.1 through 3.7 – describe each of these drivers as well as its impact on turbine prices, as shown in Figure 3. Before proceeding, however, we note that Sections 3.1 through 3.3 – on labor costs, warranty provisions, and turbine manufacturer profitability, respectively – draw heavily from the financial reports of one of the largest wind turbine manufacturers in the world – Vestas. Though it is not the intent of this article to focus exclusively on Vestas turbines or reach conclusions that are applicable only to Vestas, relying on Vestas' financial data as a proxy for the entire U.S. market is nevertheless both necessary (e.g., Vestas is the only pure-play turbine manufacturer to serve the U.S. market and file the relevant data over this period) and logical (e.g., Vestas was the second-largest turbine

[6] It is important to recognize that the wind power industry was not alone in seeing upward pressure on project costs in the years prior to the global financial crisis – other types of power plants experienced similar increases in capital costs. In September 2007, for example, the Edison Foundation published a report showing increases in the installed cost of both natural gas and coal power plants that rival that seen in the wind industry, with cost drivers overlapping those that are highlighted for wind in the present study (Chupka and Basheda 2007). Similarly, the IHS CERA Power Capital Cost Index ("PCCI") of coal, gas, solar, and wind power plants indicates that the average cost of these power plants increased by 90% from 2000 through 2008 (IHS CERA 2011), and have since declined by roughly 10% (though the index has recently begun to creep higher once again). Cost increases for conventional power plants are also covered in Winters (2008).

[7] To clarify, the period of interest to this analysis is 2002-2010. In order to capture changes that took place in 2002, however, we must also rely on data from 2001. As such, 2001 data are reported in some cases throughout the document.

supplier to the U.S. market during this period), for reasons explained in Bolinger and Wiser (2011).

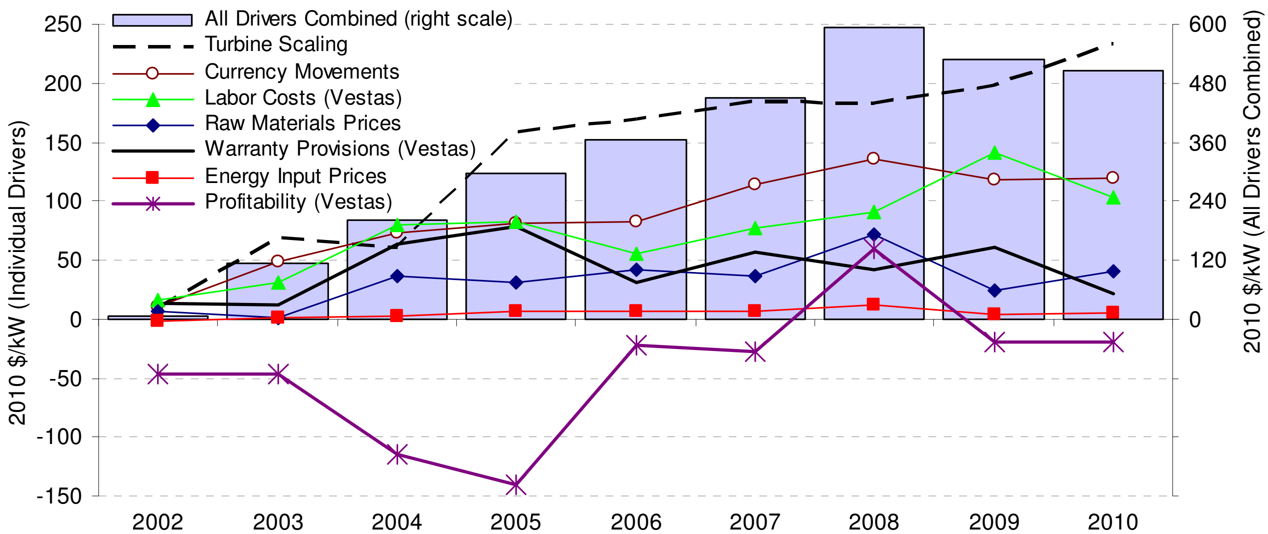

Figure 3. Cumulative Change in Turbine Price Drivers Since 2001

3.1 Labor Costs

Learning effects should theoretically drive down labor costs. As more and more technology is manufactured and deployed, manufacturers should become more efficient at utilizing – or even in some cases eliminating (e.g., through automation) – labor. When the pace of deployment is so rapid that it strains the supply of available labor, however, short-term cost increases are possible. Such was the case with the dramatic growth in installed wind power capacity over the past decade. As wind turbine and component manufacturers scrambled to address the scarcity of turbine supply, labor costs rose, leading to upward pressure on wind turbine prices.

Figure 3 shows the cumulative change in Vestas' staff costs since 2001 expressed in 2010 $/kW (delivered).[8] As shown, Vestas' reported labor costs increased by $142/kW through 2009, with a subsequent $39/kW decline in 2010. Though Vestas is understood to have historically had higher staff costs than some other turbine manufacturers (Efiong and Crispin 2007), the temporal changes in staff costs reported by Vestas are consistent with some other manufacturers. For example, though not shown in Figure 3, Suzlon's annual financial reports show a similar increase

[8] In converting to 2010 dollars, we first inflate the reported nominal Euros for all years to 2010 Euros using a Euro-area GDP deflator. Next, we convert the 2010 Euro amounts for all years into 2010 USD using the average 2010 USD/EUR exchange rate. In other words, we convert all years from EUR to USD using a single exchange rate, and as such we do not capture the impact of movements in the exchange rate over time on labor costs. This is by design, since exchange rate impacts are calculated separately later, in Section 3.7. Finally, we use MW delivered rather than MW produced and shipped for two reasons: (1) most importantly, Vestas did not publish data on MW produced and shipped prior to 2005; and (2) Vestas has recently shifted its accounting to focus more on deliveries than shipments. That said, we do acknowledge that "MW produced and shipped" is likely a more appropriate denominator than "MW delivered" for measuring per-unit labor costs, given that the production and shipment of turbines is more closely linked (temporally) with the utilization of Vestas labor, particularly for the supply-only contracts that dominate the U.S. market.

in labor costs since 2003 (available data from Suzlon do not go back any further): a $115/kW increase through 2009, with a $15/kW decline in 2010.

Not included here is an analysis of labor costs faced by component suppliers, for reasons discussed later in Section 3.3. However, if trends among component suppliers mirror those of the major turbine suppliers for which data could be obtained (Vestas and Suzlon), then the impact of labor costs on the turbine price trends presented in Section 2 would be even greater than estimated above.

3.2 Warranty Provisions

In most cases, turbine prices include the expected cost (properly discounted) of standard warranty terms. In some cases, the expected cost of any extended warranties or service contracts entered into at the time of turbine sale may also be capitalized into the turbine price. In either instance, the amount set aside by turbine manufacturers to pay for future warranty obligations will depend in large part on how reliable a turbine is perceived to be, which in turn will reflect current and past operating experience with similar machines. Increases or decreases in actual warranty claims will eventually influence the size of the warranty provisions set aside for future claims, which in turn will impact wind turbine prices.

Figure 3 shows the cumulative change in a synthetic time series of Vestas' warranty provisions since 2001; Bolinger and Wiser (2011) explain why and how the synthetic time series was constructed. The conversion to 2010 $/kW (delivered) was accomplished exactly as described earlier for labor costs – i.e., by design, the impact of exchange rate movements over time are not captured here.

The rather steep $78/kW increase in warranty provisions through 2005 reflects concerns throughout the industry in the early-to-mid-2000s about turbine reliability and warranty claims for both on- and offshore projects. For Vestas, the most visible manifestation of this concern (though involving an offshore project) was the well-publicized replacement of all 80 transformers and generators at the 160 MW Horns Reef wind project within just two years of its 2002 commissioning. In late 2005, Vestas implemented the "Will to Win" campaign, which focused on returning the company to healthy profitability through a dual strategy of cost reduction and price increases (Vestas 2005). One of the first acts of this campaign was to reduce the standard turbine warranty period to just two years (from as long as five years previously), which is reflected in the $48/kW drop in provisions in 2006. Since 2006, provisions have oscillated somewhat, but in 2010 took another concerted movement downward, as Vestas continued to progress on quality and reliability improvements. From 2001 to 2008, Vestas' warranty provisions increased by $42/kW; since 2008 they've dropped by $20/kW.

Though not shown in Figure 3, Gamesa's annual financial reports show a similar increase in warranty provisions (though for the entire company – not just Gamesa's wind division) since 2001: a $32/kW increase through 2008, followed by a $9/kW decline since then. In addition, the unexpected increase in warranty expenditures in the mid-2000s, and the resulting increase in warranty provisions (at least through 2007), is further confirmed industry-wide by Efiong and

Crispin (2007), who report warranty expenditures increasing from 3.5% of sales in 2004 to 4.75% in 2007.

3.3 Turbine Manufacturer Profitability

Wind turbine manufacturers must be profitable to remain in business. In the face of rising costs, profitability can only be maintained by raising turbine prices commensurately – these cost-related price increases are quantified in other sections of this article that focus on labor, warranty, raw materials, and energy costs (and, more subtly, foreign exchange rate movements). In contrast, this section focuses on changes in profitability itself (i.e., independent of costs). For example, the "seller's market" for wind turbines that developed starting in 2005 provided an opportunity for wind turbine manufacturers to increase their profitability by raising prices above and beyond the amount required to cover rising costs. Conversely, the dwindling number of and intense competition for new orders since the global financial crisis of 2008/2009 has led to price reductions, partially achieved through lower profit margins. This section estimates changes in wind turbine prices attributable to changes in turbine manufacturer profitability.

Figure 3 shows the cumulative change in a synthetic time series of Vestas' operating profit (i.e., earnings before interest and taxes, or "EBIT") back to 2001; Bolinger and Wiser (2011) explain why and how the synthetic time series was constructed. Once again, the conversion to 2010 $/kW (delivered) was accomplished as described earlier for labor costs – i.e., by design, exchange rate movements over time are not captured, since they are analyzed separately in Section 3.7.

After its per-kW profit margin declined significantly through 2005 (Figure 3), Vestas raised turbine prices as part of its "Will to Win" campaign, launched in late 2005 (Vestas 2005). Partly as a result, Vestas' profits rose sharply in 2006, and then again in 2008, before falling in the wake of the global financial crisis and resulting softness in turbine sales. In aggregate since 2001, Vestas' operating profit rose $59/kW through 2008, and then fell by $78/kW through 2010. The overall average increase in turbine manufacturer profitability through 2008, from levels that were widely understood to be depressed in the early 2000s (Milborrow 2008), is confirmed industry-wide by Efiong and Crispin (2007), who show EBIT margins of -8% in 2004 increasing to 2% in 2005 and then to 6-7% in 2006-2007. Bloomberg NEF (2009), meanwhile, reports lower profit margins after the financial crisis at the end of 2008.

Of course, no wind turbine manufacturer is 100% vertically integrated; all manufacturers buy varying amounts of parts and components from specialized suppliers. As such, it is not just the profitability of Vestas (or any other wind turbine manufacturer) that influences wind turbine prices; the profitability (and labor costs, discussed earlier) of turbine component suppliers will also have an impact. Quantifying component supplier profitability (and labor costs) is challenging, however, because many component suppliers are not publicly traded (which limits the type of financial information they are required to disclose), and those that are often manufacture many other goods besides wind turbine parts (making it difficult to isolate wind-related impacts). Even if a representative data sample were available, it is not clear how one would go about quantifying impacts on a $/kW basis.[9] For these reasons, our analysis does not include the impact of component supplier profitability (and labor costs), while acknowledging that such impacts do exist and have likely exacerbated the trends presented above for Vestas. Bloomberg NEF (2009), for example, reports that in the wake of the financial crisis, that both turbine *and* component manufacturers have experienced lower EBIT margins.

3.4 Increasing Turbine Size and Energy Capture

The average nameplate capacity of wind turbines installed in the U.S. doubled over the period of study, from just under 0.9 MW in 2001/2002 to nearly 1.8 MW in 2010 (Figure 4). Along with this doubling in capacity, the average turbine hub height and rotor diameter also increased: hub height by one-third (from just under 60 meters to 80 meters) and rotor diameter by nearly two-thirds (from just over 50 meters to nearly 85 meters). Because mass scales more rapidly than height or length – e.g., taller towers are not only taller, but also need to be wider and thicker (and therefore heavier) to support the extra height – the rapid growth in turbine size has also impacted wind turbine prices on a $/kW basis. The fact that the capital cost of turbines can increase with size is widely understood (e.g., Dinica 2011, EWEA 2009), but the advantages in terms of lower balance of plant costs and higher levels of energy production typically outweigh those turbine price increases.

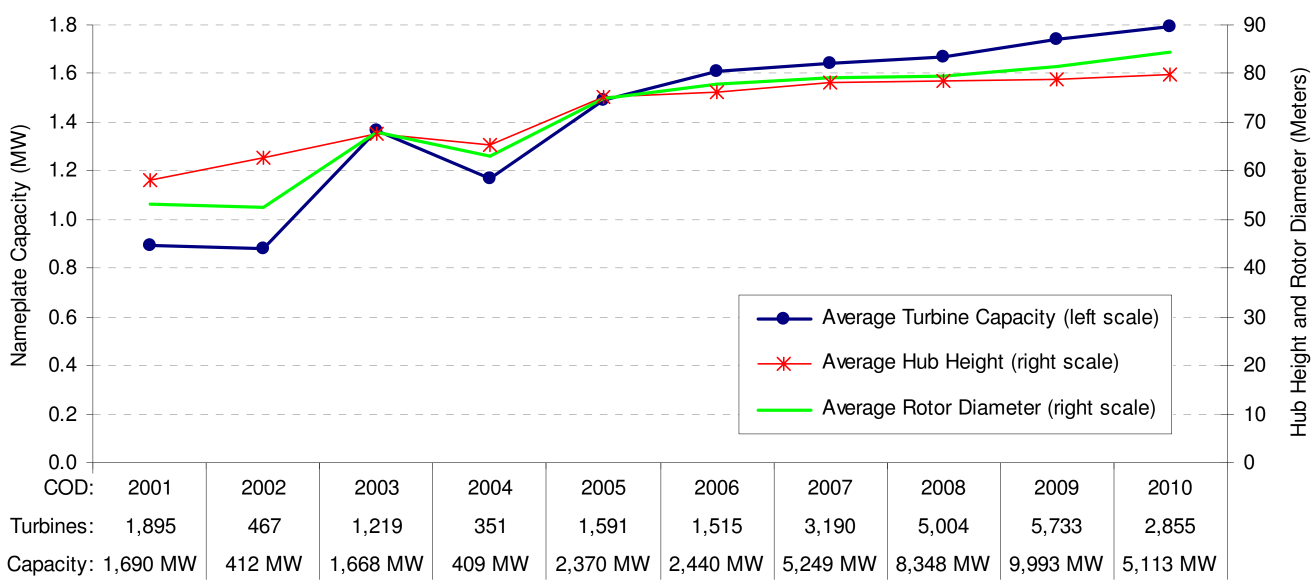

Figure 4. Average Turbine Capacity, Hub Height, and Rotor Diameter

To analyze the impact of turbine up-scaling, we use the wind turbine cost and scaling model developed at the National Renewable Energy Laboratory ("NREL") and described in Fingersh et al. (2006). The model consists of a series of cost functions developed in the early-to-mid-2000s and based on a 1.5 MW turbine platform – i.e., more or less right in the middle of both our time

---

[9] For example, knowing the number and length of blades delivered by a blade manufacturer does not automatically dictate how much nameplate capacity those blades support, since some could be installed on 1.8 MW turbines, others on 2.0 MW turbines, and still others on 3.0 MW turbines (e.g., Vestas offers V90 turbines – i.e., turbines with a 90 meter rotor diameter – rated at all three of these nameplate capacities).

period of study *and* turbine size range. The functions calculate how both mass and costs might change in response to changes in certain turbine design parameters such as nameplate capacity, hub height, and rotor diameter. The model also estimates how turbine scaling affects the levelized cost of electricity ("LCOE") generated by the turbine, based on general wind shear assumptions, power curve data, and other parameters.

Figures 3 and 5 provide the results of simply inputting each combination of average nameplate capacity, hub height, and rotor diameter from Figure 4 into the NREL scaling model. As turbine capacity and size scales up, so does mass, which in turn increases the estimated cost of the manufacture and transport of the turbine – by roughly $230/kW since 2001 (Figure 4). As noted earlier, however, this capital cost increase is not without benefit – Figure 5 shows that larger and taller turbines deliver higher capacity factors and a lower levelized cost of electricity. In other words, unlike most of the other factors that have driven turbine prices higher over the period of study, turbine up-scaling is the result of a conscious decision to design larger and more powerful turbines that can capture more of the wind's energy and convert it to electricity at lower costs. In this case, the benefit (lower LCOE) outweighs the incremental cost (higher $/kW turbine price) of scaling.

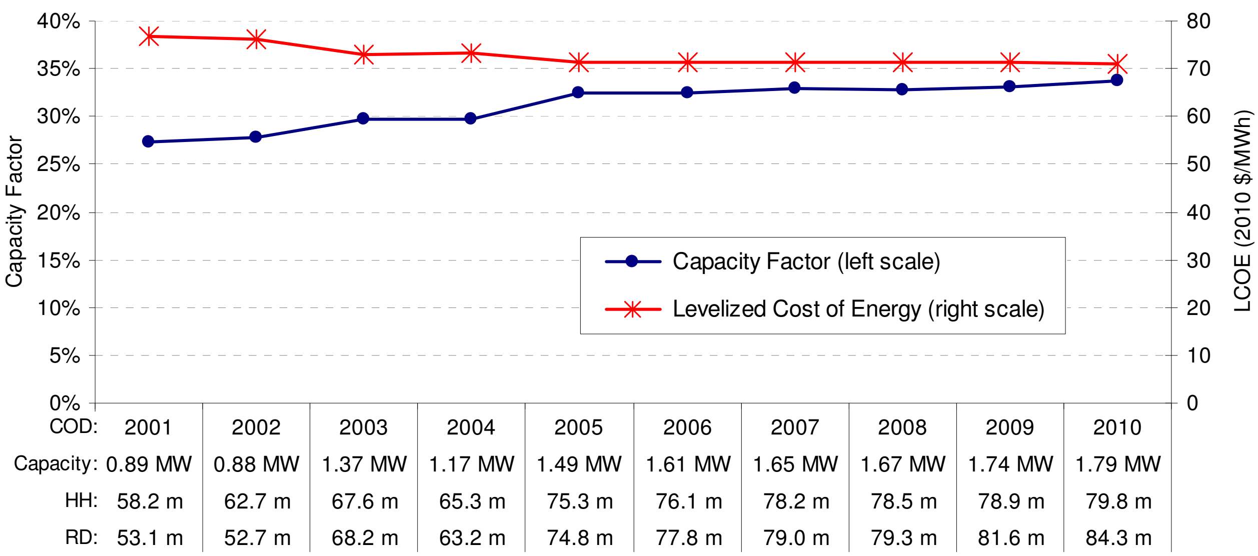

Figure 5. Results from NREL Turbine Scaling Model: Capacity Factor and LCOE

In summary, this analysis suggests that turbine scaling has increased turbine pricing over the 2002 through 2010 period, but with the benefit of increased energy capture and lower LCOE. Before leaving this driver, however, a handful of caveats are in order. First, the NREL cost model relies on standard relationships between component size, weight, and other design parameters; to the extent that design innovation has fallen outside the bounds of these standard relationships, actual scaling-related cost influences may have differed from what is presented above. Second, the analysis above was focused exclusively on turbine scaling, but turbines today also have features and capabilities that exceed those that were available in the early 2000s (e.g., sophisticated control systems, grid-friendly features, etc.). These additional design and engineering improvements – many of which were likely implemented to boost reliability in the face of the rising warranty claims/provisions discussed earlier in Section 3.2 – impose an additional cost (and benefit) that is not captured by our focus on scaling alone. Third, all of the capacity factor and LCOE estimates in Figure 5 reflect an average wind speed of 7.25 m/s at 50 meters (corresponding to a Class IV wind resource) and no subsidies. To the extent that the turbine scaling shown in Figure 4 has been associated with a shift towards the development of lower-wind-speed sites (e.g., Class III rather than Class IV), the increase in capacity factor and decline in LCOE shown in Figure 5 could therefore be over-stated. Fourth, the increase in capacity factor is due in part to the fact that the average turbine's rotor swept area has increased relative to its nameplate capacity over this period – a change that automatically boosts capacity factor, even absent other scaling or efficiency improvements. Finally, the LCOE calculations only capture scaling-related impacts on initial capital costs and energy capture, and do not account for the potential impacts of scaling on operating costs (i.e., the NREL model simply assumes that O&M costs do not change with scaling). The impact of this omission is unclear: on one hand, replacement parts for larger turbines will likely be more expensive (a positive correlation between scaling and operating costs); but on the other hand, for a given amount of capacity there will be fewer parts to replace, fewer turbines to climb, etc. (a negative correlation between turbine scaling and operating costs).

3.5 Raw Materials Prices

Wind turbines are material-intensive. Each individual tower, perhaps extending eighty meters or higher, may require several hundred metric tonnes of steel. Significant amounts of fiberglass and resin are required for the blades and nacelle. Iron, copper, and aluminum are also commonly used for various elements of the drive train and generator. Sustained movements in the price of any of these raw materials could explain part of the increase and subsequent decrease in turbine prices over the past decade, just as similar trends impact the cost of other forms of power generation equipment (e.g., Chupka and Basheda 2007). Using somewhat different approaches and data sources, previous efforts to estimate these impacts on wind energy include Greenacre et al. (2010) and Milborrow (2008).

Table 1 provides a breakdown, by mass and percentage of total mass, of the five major materials used to manufacture four different wind turbine models – three from Vestas and one from Gamesa – which span a significant range of nameplate capacity (from 1.65 MW to 3.0 MW), rotor diameter (from 80 to 112 meters), and tower height (from 67 to 84 meters). The data are compiled from life-cycle analyses ("LCAs") of wind power projects using these four turbine types. Although these LCAs often provide more detail than reported here, Table 1 consolidates closely related materials (e.g., different types of steel) into single categories where logical, while ignoring other minor (at least in terms of mass) materials whose costs are difficult to track (e.g., electronics). In all cases, materials used in the foundations of these turbines (e.g., steel rebar and concrete) are excluded from Table 1, since the empirical turbine prices shown earlier in Figure 2 are generally assumed to *not* include foundation costs, which, again, most often fall under BOP or EPC contracts and are not covered in the present study.

The bottom of Table 1, which presents the mass of each of the five materials categories expressed as a percentage of total turbine mass, reveals two important findings that enable us to simplify the present analysis. First, the fact that these five materials account for more than 98% of the total mass of each of these four turbines suggests that focusing the analysis on just these five materials, rather than on the more-detailed breakdown of materials that can be found in some LCAs, is sufficient.[10] Second, the fact that the distribution of mass among these five materials is relatively consistent across the four different turbine models suggests that the analysis will yield similar results regardless of which turbine is analyzed. Because, however, the 1.65 MW turbine most closely matches the average turbine size over the study period (see Figure 4), and because Vestas has installed a substantial number of 1.65 MW turbines in the U.S. (more than it has any other size turbine) over the *entire* study period, the analysis of raw materials (and later energy) prices focuses exclusively on the Vestas V82 1.65 MW turbine (i.e., the first data column of Table 1).

Table 1. Condensed Bill of Materials for Four Different Turbines

Turbine make/model:	**Vestas V82**	**Gamesa G8X**	**Vestas V80**	**Vestas V112**
Nameplate capacity:	1.65 MW	2.0 MW	2.0 MW	3.0 MW
Tower height:	78 meters	67 meters	78 meters	84 meters
Rotor diameter:	82 meters	80 meters	80 meters	112 meters
Mass (kg per kW)				
Steel	96.3	82.3	104.7	81.7
Fiberglass/Resin/Plastic	18.2	11.1	12.3	16.3
Iron/Cast Iron	17.8	16.3	10.3	21.9
Copper	1.8	1.8	1.4	1.6
Aluminum	1.9	0.0	0.8	1.1
Total	**135.9**	**111.4**	**129.6**	**122.7**
% of Total Turbine Mass				
Steel	70%	74%	81%	66%
Fiberglass/Resin/Plastic	13%	10%	9%	13%
Iron/Cast Iron	13%	15%	8%	18%
Copper	1%	2%	1%	1%
Aluminum	1%	0%	1%	1%
Total	**98.3%**	**100.0%**	**99.9%**	**99.0%**

Source: Vestas 2006b, Martínez et al. 2009, Elsam 2004, D'Souza et al. 2011

Figure 6 shows the cumulative percentage change in prices (in real 2010 dollar terms) since December 2001 for each of the five materials listed in Table 1 (Appendix A of Bolinger and Wiser (2011) provides details on how the individual time series price data for each material were sourced and constructed). With the exception of fiberglass/resin, the prices for all other materials shown in Figure 6 have escalated at rates faster than the general rate of inflation over this period. Specifically, the four metals experienced massive price increases that uniformly peaked in mid-2008, before plunging sharply through the end of that year as a result of the global financial crisis. Notably, metals prices have since moved higher once again.

[10] The handful of raw materials broken out in some LCAs but not listed in Table 1, and that will be excluded from the analysis on the basis of contributing very little mass, do not account for a disproportionate amount of overall turbine costs. Although the value-added from manufacturing these materials into turbine components may result in relatively expensive components (e.g., electronics), the underlying materials themselves are all relatively common and not disproportionately expensive, which suggests that the present analysis of raw materials prices will not be overly biased by excluding them.

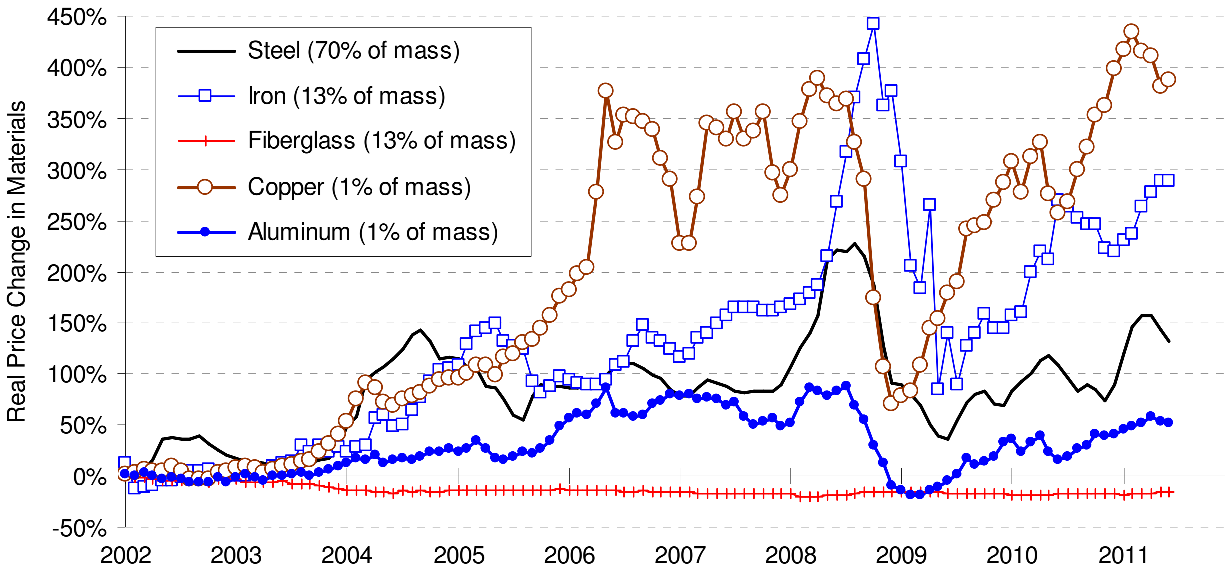

Figure 6. Cumulative Price Change in Raw Materials Since December 2001

Assuming full pass-through of the commodity price changes shown in Figure 6 to the price of materials used to manufacture the Vestas V82 1.65 MW turbine,[11] the run-up in raw materials prices from 2002 through 2008 is estimated to have added roughly $71/kW to wind turbine prices (Figure 3). A significant portion of this increase ($47/kW) was erased in 2009 as metals prices plunged, but the recovery in prices in 2010 added back $16/kW. Among the five materials analyzed, the price of steel has had by far the largest impact on turbine prices (during both the period of increase and decrease), reflecting the relative importance of steel in terms of both mass and turbine price contribution (Table 5 in Section 4 shows results by individual material).

3.6 Energy Prices

Life-cycle analyses of wind projects find that the amount of electricity generated by the project during its operating phase far outweighs the amount of energy consumed by all other life-cycle phases combined (for a literature survey, see Wiser et al. (2011)). In most cases, the "energy payback period" is found to be less than a year. Nevertheless, it does take a significant amount of energy to manufacture a wind turbine and transport it – often over long distances – to a project

[11] In the short term, changes in the price of raw materials may not flow through completely to wind turbine prices, for a number of reasons. Wind turbine manufacturers and their component suppliers may have long-term contracts or price hedges in place that serve to limit the impact of short-term fluctuations in commodity prices. In addition, manufacturers may be willing to absorb (in the case of rising raw materials prices) or reluctant to pass along (in the case of falling materials prices) short-term changes in commodity prices, to gain market share or expand profit margins, respectively. Over the longer term, however, changes in the costs of production will presumably flow through more completely to the price of finished goods. And even over the short term, turbine manufacturers generally prefer to index the price of their turbine supply agreements to commodity price movements. For example, Vestas' 2010 annual report states that Vestas does hedge commodity price risk by entering into long-term contracts, but that "In general, however, Vestas seeks to incorporate commodity price developments into its sales contracts. The final project price typically depends on developments in a number of key parameters, especially commodity prices. Where a customer seeks certainty for the final project price, this is reflected in a premium that compensates Vestas for the risk undertaken" (Vestas 2011a).

site, and a sharp rise in the cost of energy used during these two phases could, therefore, have an impact on wind turbine prices. This section explores this possibility.

As it was in the previous section, Vestas' LCA of its V82 1.65 MW turbine (Vestas 2006b) is also the principal source used here for the amount of energy consumed during the manufacture and transport of a wind turbine. Table 7 of Vestas (2006b) shows the consumption of a variety of primary energy sources – including hard coal, lignite (soft coal), crude oil, natural gas, uranium, and a variety of renewable fuels (biomass, wind, hydro, solar, geothermal) – over the life of a V82 wind turbine, but does not break out energy consumption by life-cycle stage (we are only interested in the two stages that impact turbine prices – i.e., manufacturing and transport). Table 6 of Vestas (2006b) does provide such a breakout, but only for the fossil fuels. If one assumes, however, that all of the nuclear and renewable fuels listed in Table 7 (of Vestas 2006b) are consumed during the manufacturing stage,[12] then one can use the numbers provided in that table for these resources, while using fossil fuel consumption from just the "Production" and "Transport" columns of Table 6 (of Vestas 2006b). Adding all of these together suggests that the amount of primary energy consumed during just the manufacturing and transport stages of the turbine's life cycle comes to 9.36 GJ/kW in total (Table 2).[13]

Table 2. Primary Energy Consumed by Production and Transport of Vestas 1.65 MW Turbine

	GJ / kW	% Contribution
Crude oil[A]	2.635	28%
Hard coal[A]	3.808	41%
Lignite[A]	0.170	2%
Natural gas[A]	1.750	19%
Uranium	0.428	5%
Biomass	0.201	2%
Wind	0.008	0%
Hydro	0.348	4%
Solar	0.007	0%
Geothermal	0.002	0%
Total	**9.357**	**100%**

[A]Fossil fuels are a combination of "Production" and "Transport" columns from Table 6 of Vestas (2006b), converted to MJ/kWh using conversion factors in Table 7 of Vestas (2006b). All other fuels are pulled directly from Table 7 of Vestas (2006b).

One more transformation is then required for the present analysis. Like most life-cycle analyses, the Vestas V82 LCA tracks the amount of *primary energy* consumed by the turbine over its lifetime. Primary energy is the most basic and comprehensive expression of energy needs, and

---

[12] Presumably very little nuclear or renewable power is used during the transport and operations stages of the life cycle. Though some may be used during the disposal stage, it is perhaps just as likely – based on the fossil fuel numbers from Table 6 (of Vestas 2006b) – that nuclear and renewable resource consumption during the disposal stage is *negative*, reflecting a recovery of some of the energy used to manufacture the turbine originally due to materials recycling. On balance, therefore, the most logical course of action is to simply attribute all of the nuclear and renewable power to the production stage. Even if this attribution is not entirely correct, any error only affects 11% of total energy consumption, thereby minimizing its overall impact.

[13] Although the boundaries of the various life-cycle stages can vary by LCA (e.g., some include turbine erection within the transport phase, while others do not), thereby limiting the usefulness of comparisons, several other Vestas LCAs reviewed for this article find similar energy consumption among the first two life-cycle phases (manufacture and transport). For example, the LCA of the Vestas V90 3.0 MW turbine (Vestas 2006a) found 9.44 GJ/kW, while the more recent LCA of the Vestas V112 3.0 MW (D'Souza et al. 2011) found 10.5 GJ/kW.

includes not only the energy consumed during the manufacturing process (for example), but also the energy embodied in the manufacturing inputs themselves (e.g., the energy required to convert iron ore into usable steel). Although this focus on primary energy is appropriate for calculating the turbine's lifetime energy payback (i.e., one of the goals of most LCAs), it is problematic for the present purposes, in that the raw materials prices analyzed previously in Section 3.5 already include the cost of the embodied energy used to produce them. To avoid double-counting, embodied energy must therefore be removed from total primary energy consumption.

Table 3. Primary Energy Embodied in Materials Used to Build a Wind Turbine

	Vestas 1.65 MW	Primary Energy Consumption	
	kg/kW	MJ/kg	GJ/kW
Steel[A]	112.7	25.65[B]	2.890
Concrete	487.9	3.68	1.795
Fiberglass/Resin	18.2	45.7[C]	0.831
Iron/Cast Iron	17.8	36.3	0.645
Copper	1.8	78.2	0.137
Aluminum	1.9	39.15[B]	0.074
Total	**640.1**		**6.372**

[A] Includes steel used in turbine foundation; hence, this mass does not match that shown earlier in Table 1, which excluded foundations.
[B] The primary energy content of steel and aluminum represent the average of the minimum and maximum values provided by Schleisner (2000).
[C] Schleisner (2000) does not include fiberglass, so the energy content provided for "Plastic (polyester and epoxy)" is used instead.

Schleisner (2000) provides an estimate of the amount of primary energy required to produce, transport, and manufacture a single kilogram of a variety of materials, including most of the materials used to build a wind turbine. Specifically, all materials listed in Table 1 of the previous section – with the exception of fiberglass/resin, for which "plastic (polyester and epoxy)" is substituted – are included in Schleisner (2000). Multiplying the mass of the five materials listed in Table 1 of the previous section – plus concrete[14] – by the primary embodied energy content from Schleisner (2000) yields the values shown in Table 3. In total, the materials used to produce a wind turbine are thereby estimated to contain roughly 6.372 GJ/kW of embodied energy, with steel and concrete together containing nearly 75% of the total.

Subtracting the amount of primary energy embodied in wind turbine materials (6.37 GJ/kW) from the total amount of primary energy consumed during the manufacturing and transport phases (9.36 GJ/kW) leaves just the amount of energy required to manufacture and transport the turbine itself: 2.99 GJ/kW. In other words, the energy consumption that is of relevance to this study is about one-third of the total primary energy required to manufacture and transport a wind turbine; the remainder is energy embodied in the materials themselves.[15]

[14] Because the wind turbine prices shown in Figure 2 earlier are generally assumed to *not* include the cost of foundations, concrete was excluded when analyzing raw materials costs in Section 3.5. LCA data on energy consumption during the transport phase, however, includes the energy required to construct a foundation, as well as the energy embodied in the concrete and steel that comprise the foundation. As such, it is appropriate to include concrete when calculating embodied energy (for this same reason, the mass of steel shown in Table 3 is larger than that shown earlier in Table 1 – the difference is the rebar used in the foundation).

[15] One can arrive at a similar estimate coming from a different direction through a back-of-the-envelope calculation pieced together from various sources. A figure on page 53 of Vestas (2010a) suggests that Vestas factories are responsible for 9% of total primary energy consumption during the life cycle of a Vestas wind turbine, with another 8% attributed to transport and installation and the remaining 83% attributed to raw materials and Vestas' suppliers (unfortunately, this 83% is not broken down between raw materials and suppliers). In combination, Figures 5, 15,

Table 2 above lists the estimated percentage contribution of the various energy sources that, at least in the Vestas 1.65 MW LCA, supply the primary energy consumed by the manufacture, transport, and installation of a wind turbine. These proportions cannot be directly used in our analysis, however, because they include the energy embodied in materials. Assuming that a disproportionate amount of the embodied energy derived in Table 3 comes from coal (Schleisner 2000), we make a simplifying assumption that 60% of primary energy consumption (after subtracting out embodied energy) comes from the three fossil fuels (split evenly between them, and with oil taking the form of diesel fuel), with the remaining 40% coming from largely stable-priced energy sources (e.g., nuclear and renewables) – i.e., we assume that only 60% of energy consumption is subject to fuel price risk. Though approximate, these round proportions are broadly consistent with the Vestas 1.65 MW LCA (once coal-heavy embodied energy is stripped out), as well as the more-recent Vestas V112 LCA (D'Souza et al. 2011). Detailed "end-use" energy consumption data reported in the "Sustainability" section of Vestas' web site also broadly support this apportionment.

Figure 7 shows the cumulative percentage change in prices (in real 2010 dollar terms) since December 2001 for each of the three variable-priced energy sources (Appendix A of Bolinger and Wiser (2011) provides details on how the individual time series price data for each energy source were sourced and constructed). All three fossil fuels have escalated at rates faster than the general rate of inflation over this period. Diesel fuel and natural gas prices experienced the largest increases through mid-2008, followed by a sharp reversal through early 2009 for diesel (but rising since then), and still continuing for natural gas (at least in the U.S., where increasing shale gas production has boosted supply). In comparison, the rise in coal prices has been slower and steadier.

---

and 16 from D'Souza et al. (2011) suggest a similar, though slightly lower, share for Vestas factories – 7.4% of total primary energy consumption. Meanwhile, two different sources (Efiong and Crispin 2007, Aubrey 2007) suggest that Gamesa is roughly 50% vertically integrated – i.e., it makes roughly as many turbine components in-house as it outsources to its suppliers – and one of these sources ranks Vestas (7 out of 10) slightly lower than Gamesa (8 out of 10) on degree of vertical integration (Efiong and Crispin 2007). Thus, if we assume that Vestas factories account for 7.4% of total primary energy consumption (per D'Souza et al. 2011), that Vestas' suppliers account for at least another 7.4% (based on the degree of vertical integration at Vestas being slightly less than Gamesa's 50%, and assuming that the insourcing/outsourcing of turbine components correlates well with related energy consumption), and that transport accounts for an additional 6% (per D'Souza et al. 2011, and close to the 8% reported in Vestas 2010a), then the manufacturing and transport stages together are responsible for at least 21% of total primary energy consumption, or 2.32 GJ/kW based on energy consumption data reported in D'Souza et al. (2011). This outcome is similar in magnitude to the 2.99 GJ/kW arrived at in the text by subtracting embodied energy from LCA data.

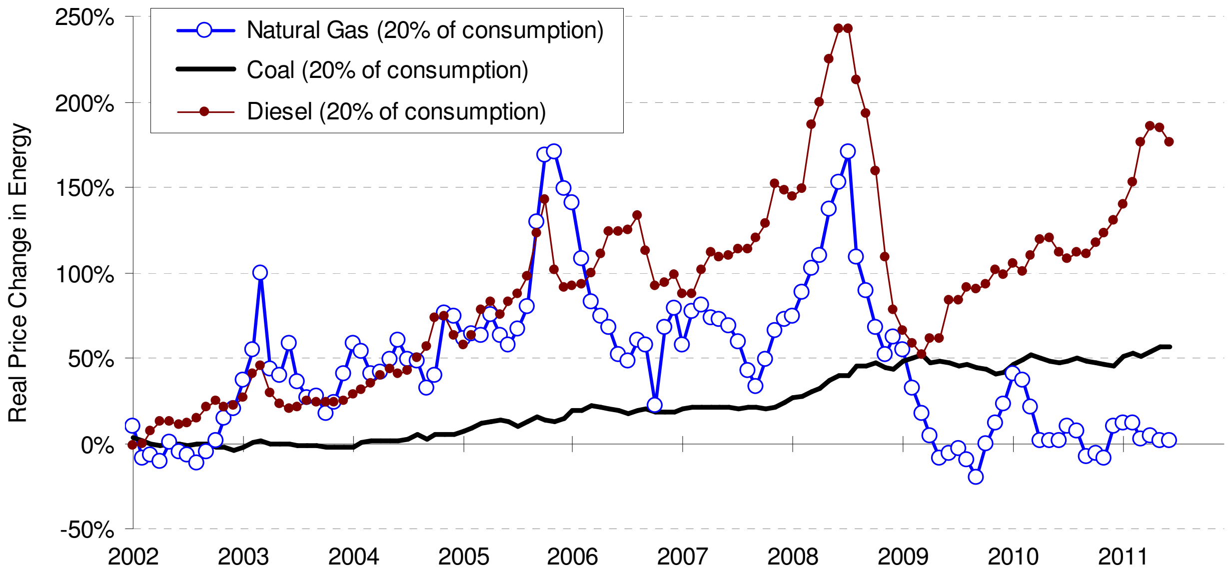

Figure 7. Cumulative Price Change in Energy Resources Since December 2001

Despite a near-doubling in aggregate fossil energy prices from December 2001 through June 2008, the contribution of energy costs to the run-up in turbine prices over this same period appears to have been relatively modest, at roughly $12/kW (Figure 3). Moreover, with the sharp decline in energy prices since June 2008, more than half of this contribution – $7/kW – has been erased.

3.7 Foreign Exchange Rates

Historically, a substantial fraction of the wind turbines installed in the U.S. have been imported, either in part or in full, from other countries. As a result, the strength of the U.S. dollar ("USD") relative to the home currencies of turbine-exporting countries has likely impacted the USD-denominated price of wind turbines over time. All else equal, the USD-denominated price of wind turbines will increase as the USD loses value, and will fall as the USD strengthens. With the USD suffering from an extended period of weakness during the years of interest to this study, exchange rate impacts could explain a significant amount of the run-up in wind turbine prices in the U.S. over this period.

Assessing the impact of exchange rate movements on USD-denominated wind turbine prices over time is complicated, however, by the fact that not only has the foreign content of turbines installed in the U.S. declined in recent years, but the mix of countries from which that declining foreign content originates has shifted over time as well. Based on trade data from the U.S. Department of Commerce, Wiser and Bolinger (2011) estimate that the fraction of installed wind turbine equipment costs imported into the U.S. fell from about 65% in 2005-2006 to 58% in 2007-2008, and then further to 40% in 2009-2010. This most recent empirical estimate – which suggests roughly 60% local content in the US on average – is generally consistent with, or even conservative relative to, similar estimates released by individual wind turbine manufacturers: Gamesa claims to offer 60% local content in the US (Gamesa 2011), Acciona 77% (Waggoner 2011), and Vestas 80-90% (Vestas 2011a).

Even though it has subsided in recent years as the import fraction has declined and the degree of local content has increased, the risk of adverse exchange rate movements inflating the cost of wind turbines imported into the U.S. has been very real throughout the period of interest to this study (i.e., 2002 – 2010). Table 4 lists those countries that have accounted for the largest estimated share of wind turbine equipment imported into the U.S. over time,[16] and thereby make up the bulk of foreign currency exposure. Figure 8 shows that from the start of 2002 through the first half of 2008, the USD had lost at least 15% of its value relative to all but one of these currencies (the Mexican Peso). Of particular note, given the high concentration of wind turbine imports from Europe, USD weakness has been especially pronounced relative to European currencies: from the start of 2002 through mid-2008, the USD lost 40% of its value against the Euro (as well as the Danish Kroner, which has moved in lock-step with the Euro).

Table 4. Share of U.S. Wind Turbine Equipment Imports Over Time

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Denmark	72.8%	54.9%	36.6%	62.1%	49.0%	37.1%	22.0%	28.1%	42.0%
Euro zone	0.0%	10.2%	0.7%	8.5%	18.6%	24.3%	30.5%	19.1%	8.7%
U.K.	0.0%	0.0%	2.9%	4.0%	2.8%	4.6%	4.1%	4.3%	0.1%
Japan	6.0%	21.6%	23.5%	10.8%	6.7%	10.5%	11.1%	20.3%	0.7%
India	0.9%	4.0%	0.0%	2.2%	15.2%	9.4%	5.9%	9.8%	16.3%
China	0.0%	0.1%	0.2%	0.3%	1.2%	5.0%	5.8%	5.9%	5.9%
Mexico	17.3%	3.6%	4.6%	2.0%	1.2%	1.4%	1.7%	1.5%	5.6%
South Korea	0.1%	4.6%	9.5%	1.7%	1.2%	2.6%	6.0%	5.3%	2.1%
Canada	1.8%	0.8%	21.7%	3.3%	0.8%	2.0%	4.3%	1.1%	8.4%
Other	*1.1%*	*0.2%*	*0.3%*	*5.1%*	*3.3%*	*3.1%*	*8.5%*	*4.6%*	*10.1%*
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Source: LBNL analysis of U.S. Department of Commerce data, via US ITC DataWeb

[16] The numbers in Table 4 capture only the imports related to the Harmonized Tariff Schedules for "wind-powered generating sets" and "towers and lattice masts," and assume that 100% of the former and 95% of the latter are attributable to wind turbines. Though other wind turbine components are also imported into the United States, wind-specific Harmonized Tariff Schedules are not available for those imports, making it difficult to discern from which countries they originated.

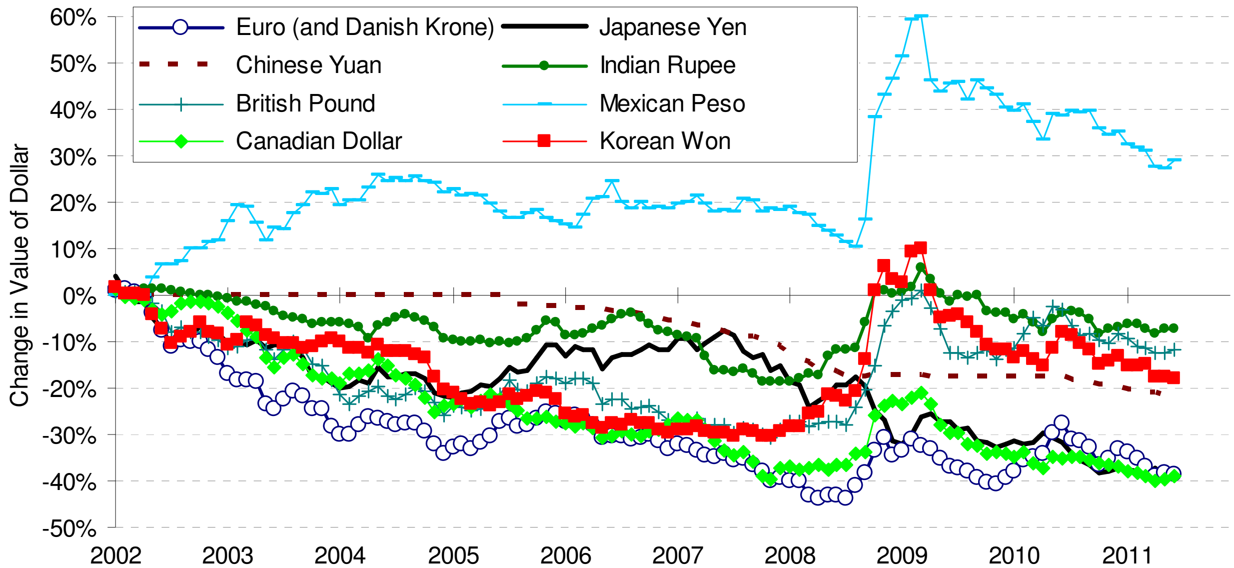

Figure 8. Cumulative Change in the Value of the U.S. Dollar Since December 2001

To estimate foreign exchange rate impacts on U.S. wind turbine prices, we start with declining turbine equipment import fractions based on the empirical data presented above, but extrapolated back in time: 70% in 2002, 68.5% in 2003, 67% in 2004, 65% in 2005, and then dropping by five percentage points each year until reaching 40% in 2010. Next, we multiply these import fractions by the corresponding average turbine price for each year as reported earlier in Figure 2, to arrive at the total average dollar amount of the turbine price that could be subject to exchange rate risk in each year. Each year, we then apportion this "at risk" USD amount among the various foreign currencies shown in Table 4 for that year (grossing them up slightly so that they add to 100%), and then convert the resulting USD amounts into the corresponding foreign currency amounts using average annual exchange rates for that year. Next, we convert these foreign currency amounts back to USD using the average annual exchange rates for the *subsequent* year (i.e., we measure the impact of exchange rate movements over the interim one-year period), sum them, and then subtract the resulting USD sum from the starting USD amount. Finally, we multiply this USD difference by 50% to reflect the likelihood that turbine manufacturers do not pass through (and may not even experience) the full extent of exchange rate impacts calculated in this manner (see Jabara (2009) and Appendix C of Bolinger and Wiser (2011) for a discussion of "exchange rate pass-through"). All amounts are expressed in 2010 USD.

The results, shown in Figure 3, suggest that USD weakness added $136/kW to the average cost of wind turbines in the US through 2008. Since 2008, there has been a $15/kW reduction as the U.S. dollar has strengthened somewhat. These results can be directly scaled up or down to accommodate different assumptions about exchange rate pass-through – e.g., doubled to reflect 100% pass-through, halved to reflect 25% pass-through.

4. Aggregate Impact of Turbine Price Drivers

The individual impacts of each of the seven drivers of wind turbine prices examined in Sections 3.1 through 3.7 are summarized in Table 5. To focus attention on the overall trends, the table presents cumulative impacts over the two periods of major turbine price movements in the past decade – i.e., the doubling in turbine prices from 2002-2008, and the subsequent softening in prices through 2010. Figure 9, meanwhile, shows yearly impacts, but of all seven drivers combined rather than individually; this aggregate impact (blue line with circle markers) is plotted against the empirical turbine price curve shown earlier in Figure 2 (red line with star markers).

Table 5. Cumulative Impact During Period of Turbine Price Increase (2002-08) and Decrease (2009-10) (2010 $/kW)

	2002-2008	2009-2010
Endogenous Drivers	**+376**	**-37**
Labor Costs	+91	+12
Warranty Provisions	+42	-20
Profit Margins	+59	-78
Turbine Scaling	+184	+50
Exogenous Drivers	**+219**	**-53**
Materials Prices	+71	-31
Steel	*+65*	*-29*
Iron	*+7*	*-2*
Copper	*+9*	*+1*
Aluminum	*+2*	*-1*
Fiberglass	*-11*	*0*
Energy Prices	+12	-7
Diesel	*+10*	*-4*
Coal	*0*	*0*
Natural Gas	*+2*	*-3*
Currency Movements	+136	-15
Total Impact	**+595**	**-89**

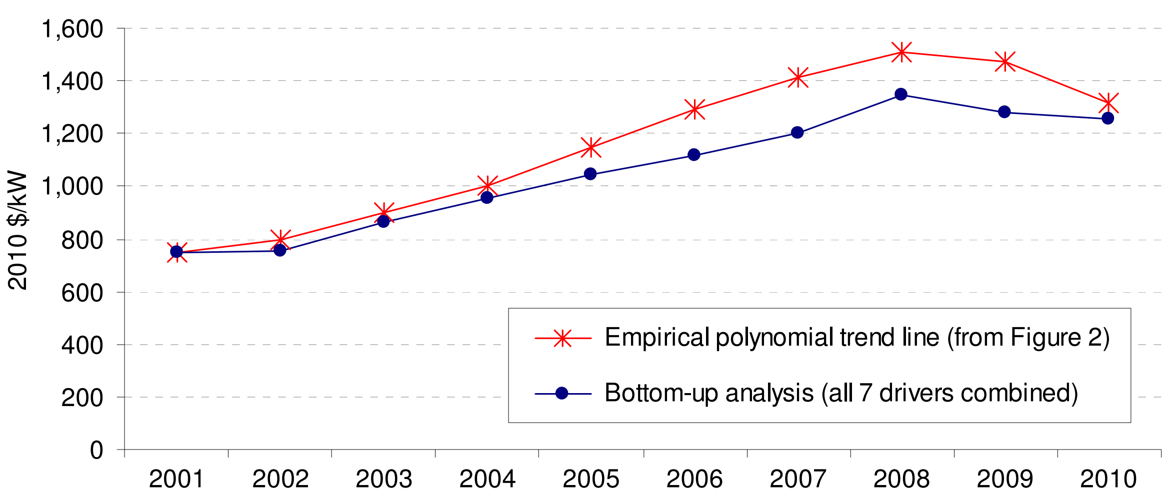

Figure 9. Yearly Impact of All Seven Drivers Combined vs. Empirical Price Curve

In aggregate, these seven drivers explain nearly $600/kW of the ~$750/kW increase in average turbine prices observed from 2002-2008, and nearly $90/kW of the ~$195/kW decrease in 2009 and 2010 (Table 5, Figure 9). From 2003 through 2010, the bottom-up analysis of these seven drivers explains between 68% and 89% (depending on the year) of the cumulative empirical price movements (Figure 9).[17] Though by no means perfect, this track record improves upon several earlier efforts (Carbon Trust 2008, Greenacre et al. 2010) that have typically failed to quantify more than 60% of observed turbine price increases.

Nonetheless, Figure 9 shows a growing gap between modeled and empirical turbine prices starting in 2005 and increasing through 2007, at which point the gap remains more or less constant until eventually narrowing in 2010. Some portion of this wedge could potentially be explained by our omission of what were likely increasing labor costs and profitability among component suppliers beginning around 2005 (discussed in Section 3.3). The magnitude of the gap – maxing out at $140/kW – is not out of line with changes in turbine manufacturer labor costs and profitability, which rose by a combined $150/kW through 2008 (see Table 5). Alternatively, or in addition, some portion of the gap could reflect higher exchange-rate pass-through than the 50% assumed here, or turbine design and engineering improvements (which, like scaling, add up-front costs that nevertheless result in tangible benefits) beyond the scaling effects that were analyzed earlier. Finally, some of the discrepancy may simply be due to methodological issues, such as the necessary reliance on Vestas data in this analysis, when the U.S. market was supplied by multiple turbine vendors over this period, and especially by GE Wind.[18]

Ignoring these other potential influences not captured here, Table 5 shows that the four partially endogenous drivers (+$376/kW) still account for more of the turbine price increase from 2002-08 than do the three partially exogenous drivers (+$219/kW). This result suggests that, even absent the considerable exogenous shocks, endogenous price drivers still would have confounded the traditional, simple application of learning curve theory by pushing turbine prices higher even as global wind power installations doubled twice over this period. It is, however, important to note that roughly half of the endogenous impact (+$184/kW) is attributable to turbine up-scaling, for which there is a direct payback in terms of a lower cost of electricity. In other words, from an LCOE perspective, the considerable capital cost impact from turbine up-scaling is not troubling, suggesting that learning effects for wind power should, arguably, be measured through LCOE rather than the more traditionally used turbine prices (or installed project costs).

---

[17] If one assumes 80% exchange-rate pass-through (rather than 50%), the explanatory power rises to a range of 77%-102%. An assumption of more than 80% exchange-rate pass-through on products exported to the U.S. would appear to be aggressive, however, given that commodities prices – most of which are already traded in USD, and are therefore not subject to exchange rate risk – make up roughly 15% of the cost of a wind turbine.

[18] Although the threat of low-cost Chinese-made turbines entering the U.S. market and driving down prices has been a common topic of discussion, by the end of 2010 only a handful of such turbines had been installed in the U.S., with no measurable impact on turbine prices during the period of our study. Until such turbines establish a track record in the U.S. and become financeable, their impact on U.S. turbine prices is likely to remain marginal. That said, the head of Vestas has reportedly expressed a goal of having Vestas turbines (which can now be mostly manufactured domestically in the U.S.) be price-competitive with Chinese-made turbines shipped from overseas (Pearson 2011), suggesting that the threat of Chinese-made turbines may soon be factored into turbine pricing strategies.

Finally, it is clear from this analysis that there is no single, dominant factor that drove turbine prices higher from 2002-08, or that has yielded lower prices since that time. Turbine up-scaling is, by a significant margin, the largest single driver, although as noted above, the estimated price impact associated with up-scaling can be seen as a reasonable expense given the performance improvements garnered by larger turbines. Currency movements are also found to have played a sizable – though somewhat uncertain – role, as did changes in labor costs and material prices. Changes in manufacturer profit margins, warranty provisions, and especially energy prices are found to play a less significant, but non-negligible role.

5. Looking Ahead

The analysis described in Section 3, with results summarized and discussed in Section 4, extends through 2010. At the time of writing, however, three quarters of 2011 have already passed, begging the question of how turbine prices have moved so far in 2011 and how the drivers highlighted in this article have been impacting those prices. Vestas (2011d) reports that Vestas' average (nominal) price on new orders worldwide during the first half of 2011 was 967 EUR/kW, down 2.5% from 992 EUR/kW in 2010. Bloomberg NEF (2011c) suggests a steeper decline, as the price of turbines within its sample that were contracted in the first half of 2011 for delivery (worldwide) in the coming twelve months fell to 940 EUR/kW, a 7% decline from 2010 levels of around 1,000 EUR/kW. Bloomberg NEF (2011c) goes on to note that the U.S. is a lower cost market than most of Europe, with average pricing pegged at $1,100/kW (i.e., consistent with the 2011 turbine price range presented earlier in Figure 2).

Declining labor costs and warranty provisions appear to be have enabled some portion of the decline (Vestas 2011d), while ongoing compression of profit margins among turbine manufacturers and component suppliers may be another contributor (Bloomberg NEF 2011c, Hauser 2011, Vestas 2011e, Weiss and Schneeweiss 2011). Though all three exogenous drivers examined in this article generally pressured turbine prices higher through the first half of 2011 (Figures 6, 7, and 8 – which show real changes in materials prices, energy prices, and foreign exchange rates, respectively – all extend through June 2011), these three drivers have since reversed course, with commodities prices generally falling and the dollar strengthening against most relevant foreign currencies in the third quarter.

All that said, as of mid-September 2011, some market participants were noting that turbine prices in the U.S. had nevertheless begun to move somewhat higher as a result of the rush to have wind turbines under contract before the end of the year in order to qualify for the Section 1603 Treasury cash grant.[19] Thus, it is not yet clear whether the turbine price reductions seen during

[19] The Section 1603 grant was originally enacted as part of the *American Recovery and Reinvestment Act of 2009*, and provides a 30% cash grant in lieu of either the Section 48 investment tax credit ("ITC") or the Section 45 production tax credit ("PTC"). In order to qualify for the grant, wind projects must be "under construction" by the end of 2011, and must achieve commercial operations by the end of 2012. Based on "safe harbor" guidelines issued by the U.S. Treasury, one way in which projects can qualify as being "under construction" is to incur more than 5% of eligible project costs by the end of 2011. In many cases, developers have been complying with the 5% safe harbor by contracting for turbines in 2011 with the intent to either take title to or delivery of a sufficient portion of those turbines in order to meet the 5% threshold by the end of the year.

the first half of 2011 will persist through the second half of the year, or how the full-year 2011 numbers will compare to 2010.

The apparent late-year rush induced by the pending expiration of the Section 1603 grant program does, however, highlight another turbine price driver – though of an indirect nature – not yet explicitly discussed in this article: policy risk. The short-term, start-and-stop policy support for wind power that has existed in the U.S. since the production tax credit ("PTC") first expired in mid-1999 created inefficiencies, artificial demand shocks, and sub-optimal investment through at least 2005 (Wiser et al. 2007). In part as a result, in 2005 when the PTC was for the first time extended (for two years) in advance of expiration, the resulting surge in demand led to major supply bottlenecks, higher labor costs, and rising profit margins – all of which (together with the other endogenous and exogenous cost pressures examined in this article) pushed turbine prices higher. By the time the industry eventually caught up to demand through increased investments in manufacturing and supply chain infrastructure, the global financial crisis of 2008/2009 had wrought significant demand destruction, leaving newly built manufacturing plants operating well below capacity in some cases (Bloomberg NEF 2011c). The Section 1603 program, with its offering of a 30% cash grant in lieu of the PTC, helped to restore demand to a degree, but is now – along with the PTC –also nearing expiration, with no clear guidance as to what, if anything, might replace it.

Having ramped up manufacturing capacity in local markets in order to meet demand while also minimizing transport costs and mitigating the risk of adverse exchange rate movements, the industry is now more robust than it was in 2005, which should enable it to focus more on driving the cost of wind energy lower, regardless of the policy environment. Even still, whether the cost of wind energy continues down the long-term downward-sloping cost curve from which it departed in 2002 – but with which it has recently re-engaged – may ultimately depend on what types of policy support are put in place post-2012. Long-term, stable policy support – even if it includes a scheduled ramp down over time to progressively wean the industry off of public support – should enable the industry to capitalize on the investments that it has already made while also planning for the future. A continuation of short-term, stop-and-go policy support, on the other hand, may lead to further rounds of artificial and inefficient demand shocks, with consequent impacts on wind turbine and wind energy pricing.

References

American Wind Energy Association (AWEA). 2011. *U.S. Wind Industry Annual Market Report: Year Ending 2010*. Washington, D.C.: American Wind Energy Association.

Aubrey, Crispin. 2007. "Supply Chain: The race to meet demand." *Wind Directions*, January/February 2007, pp. 27-34.

Berry, D. 2009. "Innovation and the price of wind energy in the US." *Energy Policy*, Volume 37, Issue 11, November 2009, pp. 4493-4499.

Blanco, María Isabel. 2009. "The Economics of Wind Energy." *Renewable and Sustainable Energy Reviews*, vol. 13, pp. 1372-1382.

Bloomberg New Energy Finance ("Bloomberg NEF"). 2011a. *US wind energy services; increased competition in an expanding market.* January 4, 2011

Bloomberg New Energy Finance ("Bloomberg NEF"). 2011b. *North America Wind Market Outlook: Q1 2011*. February 23, 2011.

Bloomberg New Energy Finance ("Bloomberg NEF"). 2011c. *Wind Turbine Price Index, Issue V*. July 27, 2011.

Bloomberg New Energy Finance ("Bloomberg NEF"). 2009. *Q3 Wind Market Outlook*. September 30, 2009.

Bolinger, Mark and Ryan Wiser. 2011. *Understanding Trends in Wind Turbine Prices Over the Past Decade*. LBNL-5119E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Bolinger, Mark and Ryan Wiser. 2009. "Wind Power Price Trends in the United States: Struggling to Remain Competitive in the Face of Strong Growth." *Energy Policy.* Vol 37, Issue 3, March 2009, pp. 1061-1071.

BWEA & Garrad Hassan. 2009. *Charting the Right Course: Scenarios for offshore capital costs for the next five years*. BWEA, London.

Carbon Trust. 2008. *Offshore wind power: big challenge, big opportunity*. Carbon Trust, London.

Chupka, Marc W., Gregory Basheda. 2007. *Rising Utility Construction Costs: Sources and Impacts*. Prepared by The Brattle Group for The Edison Foundation.

Dinica, Valentina. 2011. "Renewable electricity production costs – A framework to assist policy-makers' decisions on price support." *Energy Policy*, Volume 39, Issue 7, July 2011, pp. 4153-4167.

D'Souza, N., E. Gbegbaje-Das, P. Shonfield. 2011. *Life Cycle Assessment of Electricity Production from a V112 Turbine Wind Plant*. Prepared for Vestas by PE North West Europe ApS. February 2011.

Efiong, Asari and Andrew Crispin. 2007. *Wind Turbine Manufacturers; Here Comes Pricing Power*. Merrill Lynch Industry Overview, August 10, 2007.

Elsam Engineering A/S. 2004. *Life Cycle Assessment of offshore and onshore sited wind farms*. Document number 200128, translated by Vestas Wind Systems A/S, October 20, 2004.

Ernst & Young. 2009. *Cost of and financial support for offshore wind*. Report prepared for the Department of Energy and Climate Change, April 2009. DECC, London.

European Wind Energy Association (EWEA). 2009. *Wind Energy, the Facts*. Brussels, Belgium: European Wind Energy Association.

Ferioli, F., Schoots, K. & Van der Zwaan, B.C.C. 2009. "Use and limitations of learning curves for energy technology policy: A component-learning hypothesis." *Energy Policy*, Volume 37, Issue 7, July 2009, pp. 2525-2535.

Fingersh, L., M. Hand, A. Laxson. 2006. *Wind Turbine Design Cost and Scaling Model*. NREL/TP-500-40566. Golden, Colo.: National Renewable Energy Laboratory.

Fowler, Andrew. 2008. "Trends in Wind Power Prices, B.O.P., and Turbine Costs." *WINDPOWER 2008*. Houston, Texas, June 2, 2008.

Gamesa. 2011. *Sustainability Report 2010*.

Greenacre, Philip, Robert Gross, Phil Heptonstall. 2010. *Great Expectations: The cost of offshore wind in UK waters – understanding the past and projecting the future*. A report produced by the Technology and Policy Assessment Function of the UK Energy Research Centre.

Hauser, Christine. 2011. "G.E. Profits Are in Line With Analysts' Outlook." *New York Times*, October 21, 2011.

IHS CERA. 2011. "Power Plant Construction Costs: Cost Pressures Returning." Latest report of the *Power Capital Cost Index (PCCI)*, July 6, 2011.

Jabara, Cathy L. 2009. *How Do Exchange Rates Affect Import Prices? Recent Economic Literature and Data Analysis*. United States International Trade Commission, Office of Industries, Publication ID-21, Revised October 2009.

Koomey, J., N.E. Hultman. 2007. "A reactor-level analysis of busbar costs for US nuclear plants, 1970–2005." *Energy Policy*, Volume 35, Issue 11, November 2007, Pages 5630-5642.

Martínez, E., F. Sanz, S. Pellegrini, E. Jiménez, J. Blanco. 2009. "Life Cycle Assessment of a Multi-MegaWatt Wind Turbine." *Renewable Energy*, vol. 34, pp. 667-673.

McNerney, J., J.D. Farmer, J.E. Trancik. 2011. "Historical costs of coal-fired electricity and implications for the future." *Energy Policy*, Volume 39, Issue 6, June 2011, Pages 3042-3054.

Milborrow, David. 2008. "Dissecting Wind Turbine Costs." *WindStats Newsletter*, vol. 21, no. 4, pp. 3-5.

Nemet, Gregory F. 2006. "Beyond the learning curve: factors influencing cost reductions in photovoltaics." *Energy Policy*, Volume 34, Issue 17, November 2006, Pages 3218-3232.

Pearson, Natalie O. 2011. "China Targets GE Wind Turbines with $15.5 Billion War Chest." *Bloomberg* news, October 14, 2011.

Schleisner, Lotte. 2000. "Life cycle assessment of a wind farm and related externalities." *Renewable Energy*, vol. 20, pp. 279-288.

TPI Composites, Inc. 2003. *Cost Study for Large Wind Turbine Blades: WindPACT Blade System Design Studies*. SAND2003-1428. Albuquerque, New Mexico: Sandia National Laboratories.

U.S. International Trade Commission (USITC). 2009. *Interactive Tariff and Trade Dataweb (Dataweb)*. http://dataweb.usitc.gov

Vestas Wind Systems A/S. 2006a. *Life cycle assessment of offshore and onshore sited wind power plants based on Vestas V90-3.0 MW turbines*. June 21, 2006.

Vestas Wind Systems A/S. 2006b. *Life cycle assessment of electricity delivered from an onshore power plant based on Vestas V82-1.65 MW turbines*. December 29, 2006.

Vestas. 2011a. *Annual report 2010*.

Vestas. 2011b. *Full year 2010 and guidance for 2011: Operating in a market in recovery*. Presentation accompanying the Vestas Annual report 2010.

Vestas. 2011c. *Shareholder information: 1/2011*.

Vestas. 2011d. *Interim financial report, first half year 2011.* Company announcement No. 37/2011, August 17, 2011.

Vestas. 2011e. *Vestas issues profit warning due to delayed commissioning of new generator factory.* Company announcement No. 44/2011, October 30, 2011.

Vestas. 2010a. *Annual report 2009*.

Vestas. 2010b. *New accounting polices for supply-and-installation projects and their effect on 2006-2011*. Company announcement No. 44/2010, November 22, 2010.

Vestas. 2010c. *Implementation of IFRIC 15: Re-state accounts, Translation of guidance for 2010*. November 22, 2010.

Vestas. 2005. *Strategic plan of action 2005-2008*. Stock exchange announcement No. 16/2005, May 26, 2005.

Villadsen, Lars. 2011. Personal communication with Lars Villadsen, Senior Specialist, Investor Relations, Vestas. July 2011.

Waggoner, Tom. 2011. "Riding the Wind: Domesticating the Supply Chain – One Part at a Time." Presentation at *WINDPOWER 2011*, Anaheim, California, May 25, 2011.

Weiss, Richard and Zoe Schneeweiss. 2011. "Siemens Wind-Power Unit Aims to Return to Margin Exceeding 10%." *Bloomberg*, September 29, 2011.

Willow, Christopher, Bruce Valpy. 2011. *Offshore Wind: Forecasts of future costs and benefits*. Report prepared by BVG Associates for RenewableUK.

Wiser, Ryan, and Mark Bolinger. 2011. *2010 Wind Technologies Market Report.* LBNL-4820E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Wiser, R., Z. Yang, M. Hand, O. Hohmeyer, D. Infield, P. H. Jensen, V. Nikolaev, M. O'Malley, G. Sinden, A. Zervos. 2011a. "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 University Press, Cambridge, United Kingdom and New York, NY, USA.

Wiser, R., E. Lantz, M. Bolinger, M. Hand. 2011b (forthcoming). *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects.* Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Wiser, R., M. Bolinger, G. Barbose. 2007. "Using the Federal Production Tax Credit to Build a Durable Market for Wind Power in the United States" *The Electricity Journal*. Vol 20, Issue 9, November 2007, pp. 77-88.