Visualizing the Production Tax Credit for Wind Energy[1]

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1. Introduction

The Production Tax Credit (PTC) has been in place for more than 20 years. It gives a credit to generators of wind energy for every kilowatt-hour they produce. However, the credit is controversial and has been allowed to expire several times before being reinstated. It is currently expired, since December 2013.

Supporters of the PTC argue that the industry needs to be subsidized long enough to reach cost parity with fossil fuels and nuclear power, which have received subsidies for decades. Critics charge that clean energy policies are too costly, distorting markets and providing windfalls to renewable energy producers.

The cost of wind energy has fallen as companies develop new generations of larger, more efficient turbines. However, some types of natural gas-fired electricity remain less expensive because America's shale gas ("fracking") boom has brought a prolonged period of low natural gas prices.

In this research brief, we set out to visualize the PTC in terms of the major private and social costs for wind energy and for its closest rival, natural gas-fired energy. This is not meant to settle debates about the many pros and cons of supporting clean energy, such as claims of "green jobs."[2] Our hope is that the charts generated by this exercise will help make more concrete the abstract notion of the "cents per kilowatt hour" in which the PTC is measured.

2. A total cost analytical framework

In order to view the PTC in context, we start with estimates of the levelized costs of producing electricity from different energy sources, as calculated by the U.S. Energy Information Administration (EIA), the statistical branch of the Department of Energy (DOE). Natural gas is currently the lowest-cost source for new electricity generation (with wind being the next lowest) and therefore offers the most stringent point of comparison.

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[1] Based on research supported by the Alfred P. Sloan Foundation
[2] Our paper "Wind Energy: Should the U.S. Continue Its Support?", which is currently undergoing peer review at *Energy Policy*, covers additional aspects of the industry, such as jobs, and includes more detail about the analysis in this working paper.

We then add estimates of other costs that may or may not be borne by the power generator, including environmental impacts, the cost of integrating an intermittent source such as wind into the utility grid, and the potential hedge value offered by long-term wind contracts. We also account for regional variations in levelized costs for wind and gas.

Our estimates are applicable to a marginal capacity expansion fueled by either wind or gas. As a consequence, we do not consider the benefits that might arise from a large addition of new capacity, such as the carbon emissions that could be eliminated by retiring a coal-fired plant. A benefit like that would apply whether the new capacity is fueled by gas or wind, and is subject to regional specificities of the existing mix of energy sources.

a. Levelized cost of wind and alternatives

To compare the cost of energy sources, EIA provides annually updated "levelized cost" estimates that cover the cost of building, running, and maintaining a plant over a projected 30-year cost recovery period. These include long-range estimates for fuel cost, financing, and utilization rates. They do not include tax incentives or the additional costs discussed below. Because some of the technologies require more construction time than others, the estimates represent plants entering operation five years after the year in which the estimate is made. In other words, the estimates published in 2013 are for plants starting service in 2018.

Table 1 shows the levelized cost and regional extremes for wind and five other technologies. Gas, using advanced combined cycle technology, is estimated to be the least expensive per kilowatt hour (kWh) at 6.6 cents on average. Wind is close behind at 8.7 cents, followed by advanced nuclear, biomass, advanced coal, and solar.

Table 1. Levelized costs for U.S. plants entering service in 2018, selected technologies (2011 cents/kilowatt-hour)

Technology	National Average Cost (Cents per kWh)	Regional Variation
Gas (combined cycle)	6.6 cents	6.0 to 7.6 cents
Wind	8.7 cents	7.4 to 10.0 cents
Advanced Nuclear	10.8 cents	10.4 to 11.5 cents
Biomass	11.1 cents	9.8 to 13.1 cents
Advanced Coal	12.3 cents	11.3 to 13.8 cents
Solar	14.4 cents	11.3 to 22.4 cents

Source: EIA (2013).

There are additional costs that these estimates do not take fully into account, and we consider three in detail. First, the cost of carbon emissions and other pollutants raises the total social cost of energy from fossil fuel plants. Second, the intermittency of wind imposes costs on the utility companies that distribute wind energy because they must ensure the availability of adequate alternative sources of supply for times when wind speeds fall. And third, there is a benefit from wind energy's predictable long-term cost versus the volatility of the price of natural gas.

b. The social cost of carbon

There are a number of potential environmental impacts from electricity generation. For instance, burning fossil fuels can create emissions of NOx, SOx, ash, mercury, particulates, methane, and carbon dioxide. We focus here on the social cost of carbon dioxide emissions, which are associated with climate change and have been extensively analyzed in the literature. We have also researched the other harmful emissions, but the amounts emitted by natural gas extraction and combustion are small enough that they would not significantly affect our results.

Estimates of the social cost of carbon dioxide emissions vary widely. Not only is the precise impact of a given amount of carbon emissions uncertain, but the effects are far enough in the future that additional unknowns further cloud the estimation process.

We averaged across the range of scenarios and discount rates presented in the Appendix of the most recent estimates from the U.S. government's Interagency Working Group on Social Cost of Carbon (2013). Looking at the lowest (5^{th} percentile), the average, and the highest (95^{th} percentile) levels, we got values of $5.94, $43.23, and $137.27 per metric ton (in 2011 dollars).

According to the EIA, each million BTU of natural gas burned will emit 117.08 pounds of CO_2.[3] This works out to be 0.82 pounds, or 0.000372 metric tons, of CO_2 per thousand kWh (converting from BTU to kWh at the appropriate high-efficiency heat rate). Multiplying this value by the per-ton cost estimates, the resulting values are 0.2 cents (5th percentile), 1.6 cents (average), and 5.1 cents (95th percentile) per kWh.

c. Cost of variability of wind power

A downside of wind power is the limited predictability and variability of the wind. In order to accommodate expected and unexpected variations of wind power over time, utilities must make offsetting investments. These can include:

- Supplementary gas turbines designed for efficient, fast ramp up and down;
- Storage systems that can be tapped when wind power drops;
- Better inter-regional grid connections that enable utilities to smooth out supply over a larger geographic area; and
- Demand response systems that can reduce electricity usage when supply drops.

A number of attempts have been made to estimate the extra cost imposed by intermittency. Lueken (2012) estimates the cost of variability for wind at $4.30 per megawatt-hour (MWh). Wiser and Bolinger (2009: 47-51) reviewed previous studies by Independent System Operators and Regional Transmission Operators and found the cost of integrating wind ranged from $.50 to $9.50 per MWh for wind

[3] Source: http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11; accessed March 1, 2014.

penetration levels ranging from 3% to 35%. Katzenstein and Apt (2012) studied wind integration in the region covered by ERCOT (in Texas) and found that variability cost estimates ranged from $3.16 to $5.12 per MWh in 2009.

In light of these estimates, we set the additional cost due to wind variability in a range from $1 to $10 per MWh, which translates to 0.1 cents to 1 cent per kWh, with an average of 0.5 cents.

d. Hedge value against gas price volatility

Wind energy offers a potential advantage to utilities in the form of long-term fixed prices. Although some wind power is sold on local spot markets, the majority of wind energy in the U.S. is committed under long-term purchase agreements. The price in a typical contract is fixed (or changes at a pre-set rate) for about 20 years.

By contrast, natural gas prices have shifted wildly, driven by a variety of supply and demand factors. After remaining below $3.00 per million BTUs for most of the 1990s, the spot price at the Henry Hub, a major distribution point, rose rapidly to a peak of $8.90 in December 2000, then oscillated up and down, hitting peaks in 2003 ($7.71), 2005 ($13.42), and 2008 ($12.69). As of March 10, 2014, the price was $4.67.[4] While most analysts foresee a period of extended low gas prices, uncertainty hangs over the market in the years ahead. Gas exports or increased use of gas by domestic customers could drive up the price faster than supply can respond.

Because of the unpredictability of gas prices, energy contracts from gas-fired plants do not generally offer long-term price guarantees. Utilities have an incentive to hedge against unfavorable price movements, but financial instruments, such as options, for hedging against gas price volatility are thinly traded beyond 5 to 10 years into the future. And some regulators prohibit hedging activity by the utilities they oversee.

Based on our discussions with, and public statements by, utility executives, the fixed-cost nature of wind energy production is recognized as a partial hedge against future spikes in gas prices, but its value is difficult to quantify and would shift with the price of gas futures. Rather than estimating the hedge value of wind directly, we calculated the theoretical cost of fixing the price of gas for twenty years, the average length of a wind power contract. The levelized cost estimates from EIA rely on a series of predicted prices for gas, so we calculated what it would cost, using “collar options” (buying a call and selling a put at the futures price), to fix twenty years of futures prices either as of the calculation date or with a two-year lag that simulates plant construction. Fixing the price of gas in this way makes a more fair comparison with the fixed-price nature of most wind energy contracts.

The exercise yielded a range of the “volatility cost” for gas, i.e., the amount a utility would need to pay to fix the price of gas at its current futures market values for twenty years, of between 0.4 and 0.9 cents per kWh, with an average of 0.65 cents.

[4] http://www.eia.gov/dnav/ng/hist/rngwhhdd.htm

3. Adjusted Levelized Cost Scenarios

Table 2 summarizes the three factors we will use to calculate an adjusted levelized cost for wind and gas, expressed as ranges between a low and a high value for each factor. The estimates necessarily rely on many assumptions, which can be more or less favorable to renewables. We have endeavored to be conservative in our approach so as not to predetermine the outcome of our analysis.

Table 2. Summary of adjustment factors, cents per kWh

	Low Estimate	**Average estimate**	**High Estimate**
Carbon Cost (added to cost of gas)	0.2	1.6	5.1
Intermittency Cost (added to cost of wind)	0.1	0.5	1.0
Volatility Cost (added to cost of gas)	0.4	0.65	0.9

Table 3 applies the average adjustment values to the national average levelized costs for wind and gas energy. We first add intermittency cost to wind, and volatility cost to gas. Wind intermittency and gas price volatility cost are characteristics that should be reflected in the price that utilities are willing to pay for wind energy, so these are private costs. The private cost of wind is 9.2 cents and for gas is 7.25 cents per kWh.

Next we add the average carbon cost to the private cost of gas. This is a true externality because it is not paid for by the producer or consumer of electricity, but imposes a burden on everyone affected by climate change, now and in the future. This gives us a more complete estimate for the full cost to society of electricity from wind and natural gas, which we call the adjusted levelized cost.

Table 3. Average adjusted levelized cost of wind and natural gas, cents per kWh

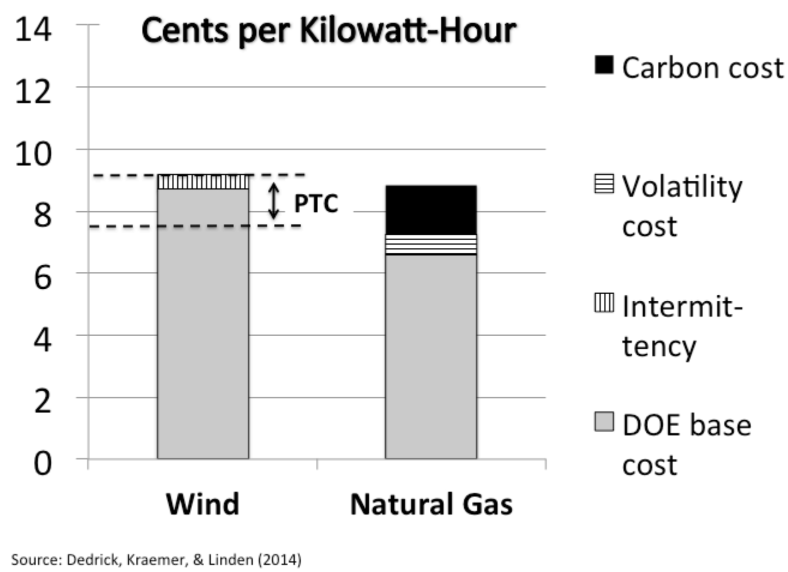
	Wind	Gas
Levelized cost (EIA)	8.7	6.6
Intermittency Cost	0.5	0
Volatility Cost	0	0.65
Private Cost	***9.2***	***7.25***
Carbon Cost	0	1.6
Adjusted levelized cost	**9.2**	**8.85**

a. Comparison of estimated wind and gas costs on average

In order to compare these numbers to the value of the Production Tax Credit, the value of the PTC also needs to be levelized. The current amount of the PTC is an inflation-adjusted 2.3 cents/kWh for ten years. For use in our levelized cost analysis, we levelized its value over twenty years, the average duration of a wind energy contract. We calculated a range of levelized values for the PTC, using various discount and inflation rates. The estimates fell between 1.53 cents to 1.76 cents per kWh, and we use a rounded average of 1.6 cents for the calculations that follow.

Figure 1 shows the average costs of carbon and price volatility (for gas) and intermittency (for wind) added on top of the official EIA levelized cost estimates for the U.S. (shown in gray). The value of the levelized post-PTC cost of wind is shown by a dashed line at 7.6 cents (9.2 cents private cost minus 1.6 cents levelized subsidy from the PTC). This means that the private cost of wind is still slightly more expensive than the private cost of gas (7.25 cents), after the PTC is taken into account.

Figure 1. Adjusted levelized cost for wind and natural gas: National average



One way of looking at the PTC is that its levelized value is large enough to compensate for the average estimated social cost of carbon dioxide emitted by natural gas combustion (1.6 cents), while recalling that the range of estimates for carbon costs is very wide. Still, the current value of the PTC is not enough to make wind privately competitive, at least not on average. However, the underlying costs vary quite a bit around the country, with the Midwest plains states having the highest-quality wind resources and correspondingly lower production costs. We look next at regional differences to see if and where wind is competitive with gas with the current PTC.

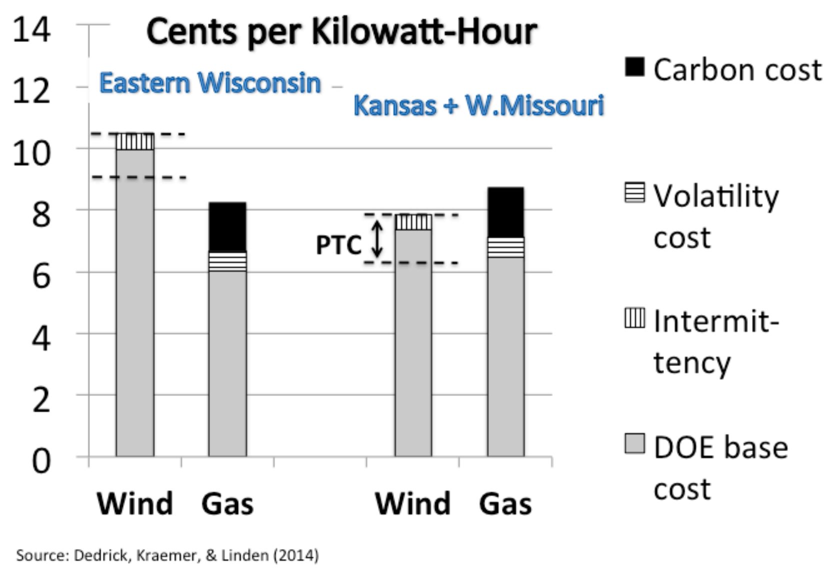
b. Regional differences in wind and gas costs

The continental U.S. is broken into 22 quasi-separate markets across the borders of which electricity trading is limited. As shown in Table 1, these regional markets have different cost profiles for gas and, even more so, for wind energy. Figure 2 shows the adjusted levelized costs of gas and wind energy for the two regions that have, respectively, the largest and smallest *difference* between the levelized costs of gas and wind, adjusted for intermittency, volatility, and carbon emissions.

In the regional data provided to us by EIA, wind is more expensive than gas in all regions. The difference is largest (3.97 cents per kWh) in "MROE", which roughly covers eastern Wisconsin. The difference is smallest (0.87 cents) in "SPNO", which covers Kansas and the western part of Missouri, where wind resources are abundant. These differences stay about the same for total private costs, because intermittency costs for wind and volatility costs for gas are almost equal. However, the adjusted levelized cost (incorporating carbon cost) for gas is higher than the cost for wind in Kansas/W. Missouri. This is where the PTC comes into play.

Figure 2 shows that the PTC lowers the private cost in Kansas/W. Missouri to less than the private cost of gas; hence, it will encourage investment in a region where the cost of wind is actually lower than the adjusted cost of gas but would not have led to investment in wind because the carbon cost is not private. In Eastern Wisconsin, where the adjusted cost of wind is higher than gas, the PTC is still not enough to stimulate wind investment. It turns out that Wisconsin is slightly more representative of the country as a whole. The post-PTC cost of wind works out to be lower than that of natural gas in 10 of the 22 regions.

Figure 2. Adjusted levelized cost for wind and natural gas: Regional extremes



4. Conclusions

Among the emerging renewable energy sources, wind energy is the largest, providing more than 4% of U.S. electricity generation in 2013. Wind energy is also expanding rapidly, accounting for over a third of *all* new generation capacity in recent years (Wiser and Bolinger, 2013). The wind industry is approaching a state where it can compete with higher-emission energy sources without government support, but, in the immediate future, wise policy can make the difference between growth and atrophy.

In this brief article, which presents part of our broader analysis of the wind industry, we have found the following:

- Wind energy is not yet privately competitive on average with natural gas as long as the price of natural gas remains low, as it has since the start of the boom in shale gas production.

- The main difference between the private and social costs of natural gas is the cost of carbon, which adds an average estimated 1.6 cents to the true cost of gas-powered electricity.
- The PTC, if levelized over 20 years at 7%, works out to roughly the same value as the average social cost of carbon.
- The PTC is not enough to make the private cost of wind competitive with gas for the U.S. as a whole, but it is enough to make a difference in regions where wind costs are already below average.

A climate change-aware energy policy would incorporate the social cost of carbon emissions into the market price of each emissions source, e.g., through a carbon tax or cap-and-trade system. While that seems unlikely in the current political environment, fiscal support for the burgeoning U.S. wind industry is helping to accomplish a similar outcome in the case of renewable energy.

The weakness of the PTC has been its repeated expiration and renewal. This creates uncertainty among investors and leads to large swings in deployment as the credit expires and later is renewed. In a cycle that has been repeated several times, a record 13 GW of wind capacity was installed in 2012 in the rush to take advantage of an expiring PTC, followed by just 1 GW in 2013.[5] Massive declines in activity such as this discourage investment in R&D, manufacturing capacity, and human resources. This likely delays the improvements in design, manufacturing and construction that are needed to bring the cost of wind down to where it is competitive without subsidies.

At the time of the writing of this paper, the PTC has expired and its future is being considered by Congress. The Obama Administration has called for making the credit permanent, while Chairman Dave Camp of the House Ways and Means Committee introduced a discussion draft of a bill that would eliminate the PTC as part of broader tax reform (Camp, 2014). In between these extremes have been recommendations to phase out the credit using different mechanisms (Brown, 2013). These phase-outs would eliminate the PTC sometime between 2017 and 2019, depending on the formula adopted. The assumption/hope is that wind costs will be competitive with natural gas by 2019 due to improvements in wind technology and/or rising costs for natural gas.

The logic for a phase-down is that it will at least give the wind industry predictability over a number of years. The industry needs stable demand to support the R&D and capital investments that will make these cost reductions possible.

As the options are debated, policymakers should take into account the full cost of each energy source, including those costs that are hidden from producers and ratepayers yet borne by all of us. The model presented in this paper can be used as a tool to visualize those costs.

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[5] http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA%204Q2013%20Wind%20Energy%20Industry%20Market%20Report_Public%20Version.pdf

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