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Wind Generation Patterns and the Economics of Wind Subsidies

An analysis supports the conclusion that there is no economic rationale for continued subsidization of wind generation. At the federal level, direct subsidies, such as the federal production tax credit, should not be continued. State-level subsidies, whether feed-in tariffs established by state regulators or statutory RPS mandates, further exacerbate market distortions and raise electricity prices, again to the detriment of consumers.

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I. Introduction

The United States has subsidized the wind industry for 35 years. At the federal level, subsidies began with the Public Utility Regulatory Policy Act (PURPA) of 1978. Under PURPA provided indirect subsidies for renewable generation through mandates that electric utilities purchase the output of qualifying facilities (QFs) based on forecasts of avoided costs, essentially ''but for'' cost projections made by the utilities and approved by state regulators, or made by those regulators themselves. With passage of the Energy Policy Act of 1992 (EPAct), wind subsidies were increased through a variety of programs. The most prominent was the federal production tax credit (PTC).[1] Although not specifically limited to wind generation, approximately 75 percent of the

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total PTC credits claimed since its inception have been for wind generation.[2] Wind generation benefits from other subsidies as well. Since 2009, for example, the wind industry has received payments under the $831 billion American Recovery and Reinvestment Act of 2009 (ARRA). Perhaps the largest subsidy has been through state-level renewable portfolio standards (RPS), which mandate minimum levels of renewable generation that electric utilities or competitive generation suppliers must obtain as part of their overall resource mix used to serve customers. Currently, 30 states, plus the District of Columbia, have such RPS mandates.

Unlike market prices for other commodities, the market price of electricity varies by season, day, and hour. In part because electricity cannot be stored cost-effectively, the price is highly dependent on daily fluctuations in demand—higher demand during the day and lower demand at night—and seasonal changes. In most of the U.S., for example, electricity demand now peaks in the summer, driven by increased use of air conditioning in commercial and residential buildings. As a result of this price variation, the value of subsidized wind generation also varies by season, day, and hour. In some hours, the value of electricity can be thousands of dollars per MWh. In other hours, the value actually can be less than zero.

The purpose of this article is to examine the economic value of subsidized wind generation. Specifically, are taxpayers and consumers who are forced to pay for subsidized wind power receiving high- or low-value electricity? Answering this question has important policy implications. First, Congress is currently considering whether or not to extend the PTC for an additional year, at an estimated cost of over $12 billion. Second, because the percentages of renewable generation required under state RPS requirements continue to increase, electricity consumers will be forced to subsidize greater amounts of wind power, which will have larger impacts on electricity costs. Third, continued subsidization of wind generation will lead to higher long-run retail prices for electricity,[3] which will have adverse impacts on economic growth. Given these reasons, determining the value consumers obtain for their subsidy dollar is highly relevant to policy decisions regarding continued subsidies.

> Are taxpayers and consumers who are forced to pay for subsidized wind power receiving high-value or low-value electricity?

II. Economic Costs of Wind Power Subsidies

Renewable energy subsidies have been advocated for a variety of reasons, ranging from common arguments about protecting emerging or ''infant'' industries so they may become established, [4] to ''two wrongs make a right'' justifications, i.e., that because fossil fuel generating resources have been subsidized, it is only ''fair'' that renewable generation be subsidized, to arguments that renewable subsidies offset external environmental costs of fossil fuel generation.[5]

Regardless of how they are justified, subsidies distort competitive markets, drive out unsubsidized competitors, and reduce the incentives to innovate and improve operating efficiency.[6] In addition to these economic costs, wind power subsidies create four other types of adverse economic spillovers because of the nature of electric markets and integrated power grids.

First, because baseload generators, e.g., nuclear and coal-fired power plants, cannot be cycled easily, these generators operate even when the market price of electricity is less than their variable operating costs.[7] As a consequence, when the demand for electricity is sufficiently low, market prices can fall below zero. In such situations, baseload generation owners are then forced to pay to generate power and inject that power into the grid,

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which exacerbates economic losses.[8] With a current after-tax PTC of $22/MWh, it is economically rational for wind generators to sell power into the market even when prices are as low as -$34/MWh.[9] As a result, negative pricing periods are exacerbated, which increases the costs for baseload generators who are unable to cycle their units and may hasten their retirement.

Second, the inherent intermittency of wind generation increases the costs of maintaining power system reliability. The intermittent nature of wind generation requires additional generating reserve capacity so as to ''firm'' wind supply. Moreover, rapid variations in wind output can require additional voltage support through automatic generation control (AGC) that automatically adjusts the output of flexible generating resources (e.g., gas-fired turbines) so as to maintain voltage and frequency within acceptable levels. A study published by the National Renewable Energy Laboratory (NREL) estimated these integration costs to be about $5/MWh.[10] In Texas, which has over 10,000 MW of installed wind capacity, in 2011 these integration costs added an estimated additional $140 million in power system costs. Nationally, integration costs were over $500 million in 2011.[11]

Third, wind generation requires additional investment in high-voltage transmission lines, because wind resources are geographically dispersed and typically located far from load centers. The costs of high-voltage transmission lines are generally socialized across all transmission system users. Texas alone spent over $6.9 billion on Competitive Renewable Energy Zone (CREZ) high-voltage transmission lines to interconnect wind power.[12]

Fourth, the demonstrated inaccuracy of short-term forecasts of wind generation increases the overall cost of meeting electric demand as system planners must reimburse other generators who had been scheduled to operate, but were not needed because actual wind generation was greater than forecast, or had not been scheduled, but were required to operate because actual wind generation was less than forecast. Although generators can be penalized for erroneous forecasts, most of the resulting system costs are socialized across all users. Despite claims by wind power advocates that wind generation can be predicted accurately several days in advance, allowing system operators to reduce, if not eliminate, the impacts of wind's volatility, actual data does not bear this out.[13]

III. The Economic Value of Wind Generation

To examine the economic value of subsidized wind generation, we analyzed wind generation in three regions where there has been extensive—and rapid—development of wind power: the PJM Interconnection, which covers the mid-Atlantic states and the Ohio Valley; MISO, which covers much of the remaining Midwestern States; and ERCOT, which oversees the electric system in almost the entire state of Texas. Together, these three regions account for over 27,000 MW of wind generating capacity, more than half of the approximately 50,000 MW of installed wind generating capacity in the U.S.[14]

Because of weather patterns that can change from year to year, we examined hourly wind generation and load data over a 44-month period, Jan. 1, 2009, through Aug. 31, 2012, to assess the relative economic value of wind power. We then evaluated the performance and availability of wind power in each of the four seasons, where each season was defined as including the months shown in Table 1.[15]

From both a system planning and customer perspective, the highest-value generating resources are those that are available when electricity demand peaks: like taxicabs that never show up when it is raining, generating resources that fail to produce when most needed have little value.

Table 1: Month-Season Mapping.

Season	Months
Winter	December–February
Spring	March–May
Summer	June–August
Fall	September–November

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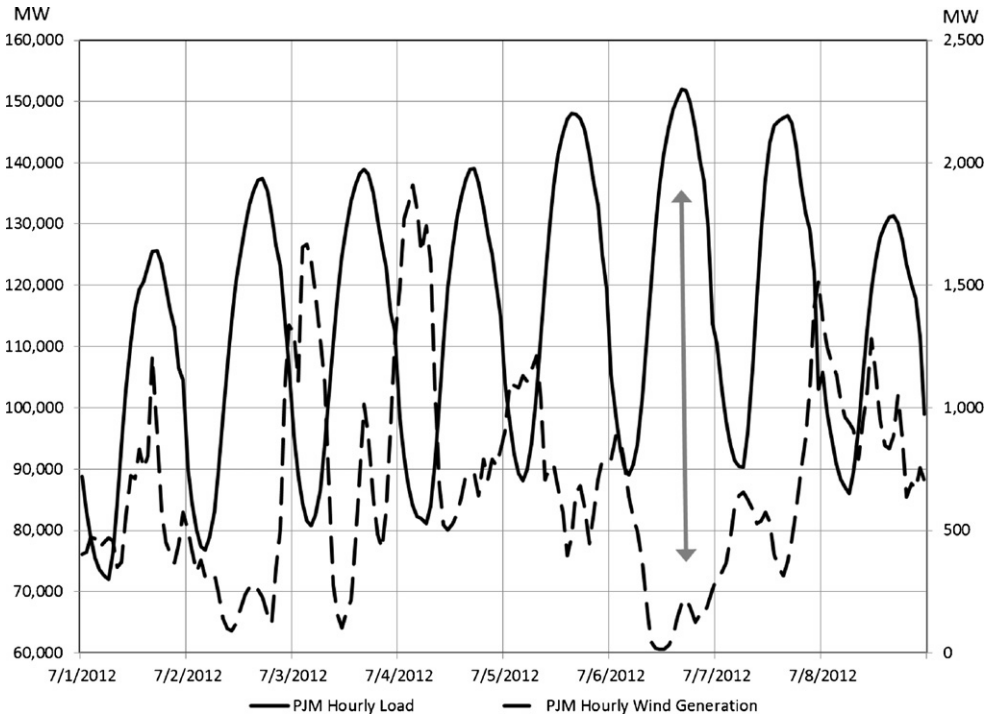

Figure 1: PJM Hourly Load and Wind Generation, July 1–8, 2012

Consider, for example, the pattern of hourly load and wind generation in PJM for the week of July 1–8, 2012, when much of the eastern U.S. was in the grip of a record heat wave (Figure 1).

Over that week, a strong negative correlation between hourly demand and wind generation is apparent. The actual correlation coefficient is -0.40.[16] As Figure 1 shows, over this week, wind generation usually peaked in the late night and early morning hours, whereas peak demand occurred in the late afternoon. Electricity demand peaked at 5 PM on July 6 of this week, when demand was over 151,000 MW. During that same hour, 201 MWh of wind power was generated by the approximately 4,700 MW of installed wind capacity in PJM, less than 5 percent of the potential generation. As little generation as that was, it represented an increase from earlier in the day, as only 14 MWh was generated during the hour between Noon and 1 PM.

In the Northern Illinois zone, which encompasses Chicago, the demand for electricity averaged 22,000 MW over the entire day; the average amount of wind power generated was just 4 MW.

From a system planning standpoint, the ''gap'' between high hourly loads and low wind output makes wind a far less valuable and far less reliable resource than conventional generating resources. This ''gap'' between peak electric demand and low wind generation is not only observable on a daily basis, but can also be observed on a seasonal basis.

To evaluate the load-wind gap, we first calculated average daily wind availability, $W_{d,y}$, during a standard 16-hour on-peak portion of each day, 7 AM–11 PM, as total wind generation relative to total potential generation based on installed wind capacity, $W_{C,m,y}$.[17] Thus,

$$W_{d;y} = \frac{1}{16}\sum_{h=1}^{16} w_{h;d;y} = W_{C;m;y}; \qquad (1)$$

where $w_{h;d;y}$ equals hourly wind generation on day d of year y. Next, we average these daily wind availability values in each season of each year to define seasonal wind availability, $\bar{W}_{S;y}$. Thus,

$$\bar{W}_{S;y} = \frac{1}{D_S}\sum_{d=1}^{D_S} W_{d;y}: \qquad (2)$$

Similarly, we define the annual wind availability, $\bar{W}_{A;y}$, as the

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average daily wind availability over year y, or

$$\bar{W}_{A;y} = \frac{1}{365}\sum_{d=1}^{365} W_{d;y}: \quad (3)$$

The seasonal wind ratio is just equal to the ratio of the seasonal and annual wind availability levels, or $\bar{W}_{S;y}=\bar{W}_{A;y}$. Next, we define the seasonal load ratio, $\bar{L}_{S;y}$, as the average load during season S of year y relative to the average annual load in year y, $\bar{L}_y$. Thus,

$$\bar{L}_{S;y} = \sum_{d=1}^{365} \frac{L_{d;y}}{\bar{L}_y}; \quad (4)$$

where

$$\bar{L}_y = \frac{1}{365}\sum_{d=1}^{365} L_{d;y} \quad (5)$$

Finally, the load–wind ''gap,'' $G_{S,y}$, equals the difference between the seasonal wind availability ratio and the seasonal load ratio:

$$G_{S;y} = \frac{\bar{W}_{S;y}}{\bar{W}_{A;y}} - \bar{L}_{S;y} \quad (6)$$

For example, suppose the seasonal load in spring of year y equals 90 percent of annual average load, but seasonal wind generation is 120 percent of annual average wind generation. Then the spring load–wind gap, $G_{Spring,y}$ equals 120–90 percent, or +30 percent. A positive load-wind gap value means there is relatively more wind generation available to serve load; a negative load-wind gap value means there is relatively less wind generation available to serve load.

From the standpoint of maximizing the economic value of subsidized wind generation, the load-wind gap should be as large as possible when load and market prices are at a maximum. That is, the economic value of subsidized wind generation will be maximized if the relative wind generation is greatest when loads are greatest. Intuitively, during peak demand hours, wind generation will displace high-cost fossil generating units; the greater the availability of wind power, the greater will be the cost savings from displacing fossil-fuel peaking units.

In contrast, when load and market prices are low, wind generation will displace lower variable-cost baseload resources. Moreover, when load is especially low and baseload resources cannot be cycled, wind generation will not displace any generation. Instead, wind will simply force baseload generation owners to pay to continue operating, driving prices below zero. In such cases, the value of wind displacement is zero; subsidized wind generation simply results in a wealth transfer from existing generation owners to wind generators and consumers. Although consumers may benefit from lower wholesale prices in the short run if load-serving entities are relying on the market, in the long run, consumers will be worse off, as demonstrated by Briggs and Kleit.[8]

Figures 2–4 illustrate the seasonal load-wind gaps for ERCOT, MISO, and PJM.

As Figures 2–4 demonstrate, however, the economic value of subsidized wind generation does not follow this pattern. In each region, there is a strong lack of wind generation during the last four summers, when electricity demand was greatest. Instead, in all three regions, the highest relative amount of wind generation occurred when loads were lowest, and the smallest amounts of wind were available when loads were greatest in summer. In PJM, this effect has been particularly pronounced, with a summer load – wind gap of almost -70 percent in summer 2010 and 2011, and -59 percent in summer 2012.

Although we did not evaluate wind generation in the Southwest Power Pool (SPP), which has about 4,800 MW of installed wind capacity, the SPP Independent Market Monitor reports similar wind output behavior during peak load hours. In 2011, for example, wind availability during all peak hours averaged just over 15 percent, whereas in the hours where loads were lowest, wind

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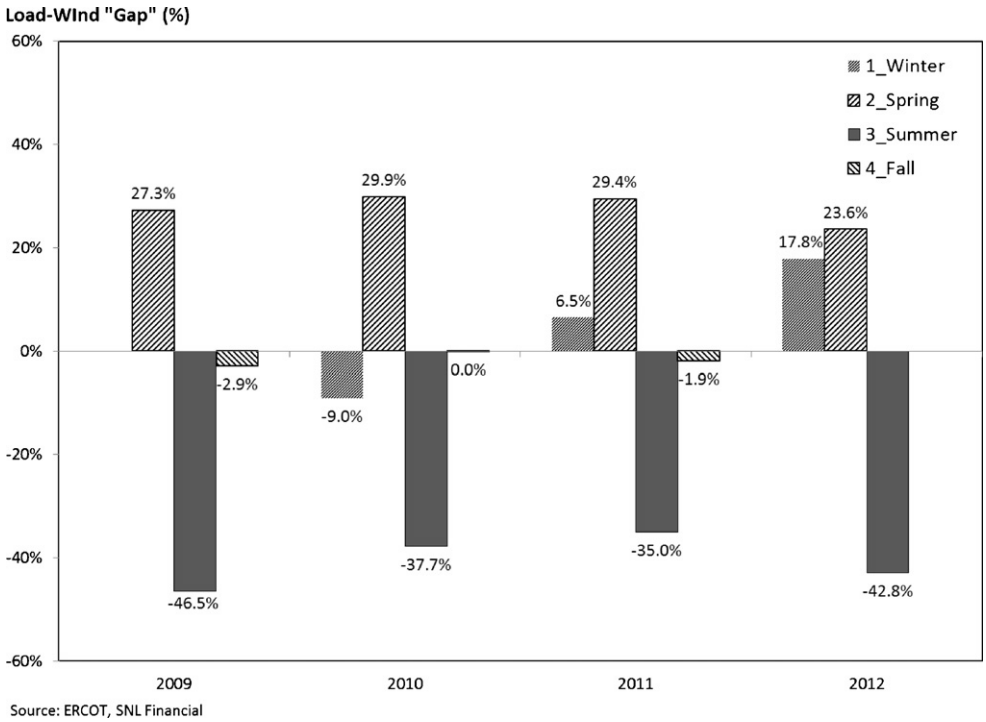

Figure 2: ERCOT Load–Wind Gap, 2009–2012

availability averaged over 40 percent.[18]

Next, we evaluated availability ratios each year during the hour when demand peaked on the 10 days with the highest greatest electricity demand in each RTO. We compared the median of the availability ratios in each year with the overall median availability over the entire

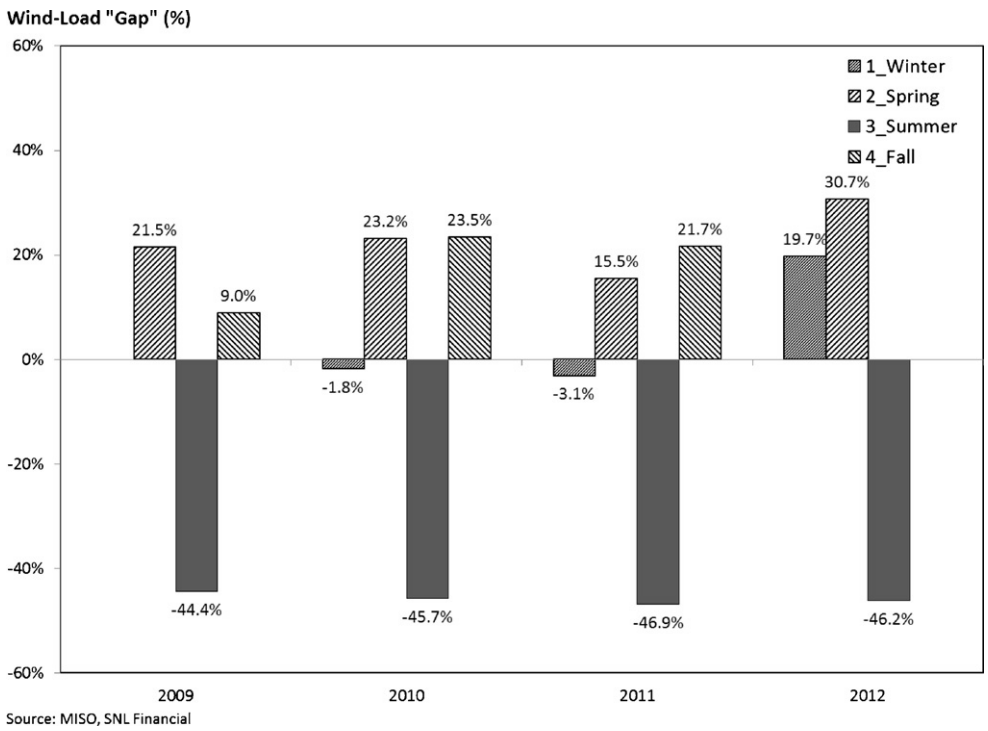

Figure 3: MISO Load–Wind Gap, 2009–2012

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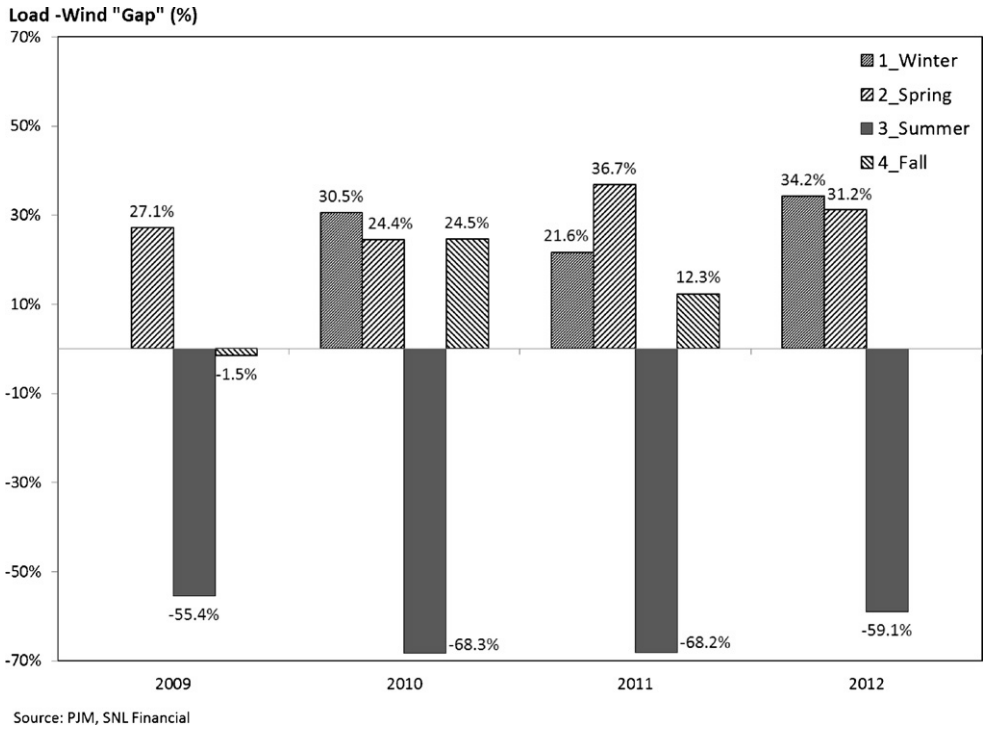

Figure 4: PJM Load–Wind Gap, 2009–2012

Table 2: Median Wind Availability, Peak Demand Days and Overall.

Year	ERCOT	MISO	PJM
2009	14.2%	1.8%	14.6%
2010	6.0%	2.5%	8.2%
2011	15.9%	7.6%	14.0%
2012	14.0%	7.2%	13.8%
Median, All-hours, All years	30.9%	27.0%	25.9%

four-year period, based on the individual daily availability ratios.[19] The results are shown in Table 2.

As Table 2 shows, in MISO, median wind availability ranged between 1.8 percent and 7.6 percent of total installed wind capacity at the peak hour on the 10 highest-demand days. In ERCOT, median wind availability ranged between 6.0 percent and 15.9 percent. In PJM, the range was between 8.2 percent and 14.6 percent. As shown, these availability values are, at best, half the median availability for the entire period and, in the case of MISO, at best less than one-fourth of the median availability. From a system planning perspective, therefore, planners must assume that little wind generation will be available on the highest-demand days.

Finally, we examined wind generation based on its relation to an average daily load profile, both seasonally and over the entire year. This is shown in Figure 5, which compares average wind availability by hour in ERCOT to average hourly electric demand over the entire four-year period, both in the summer season and on an average annual basis.

As Figure 5 shows, average hourly loads in summer are higher than during the year overall, whereas average wind availability is lower in summer. Thus, we see the same high-load/low-wind generation relationship: high-load hours are associated with low wind availability.[20]

IV. Policy Implications

Our analysis shows that continued subsidies for wind generation represent both bad economics and bad energy policy, for at least three reasons. First and foremost, wind generation's

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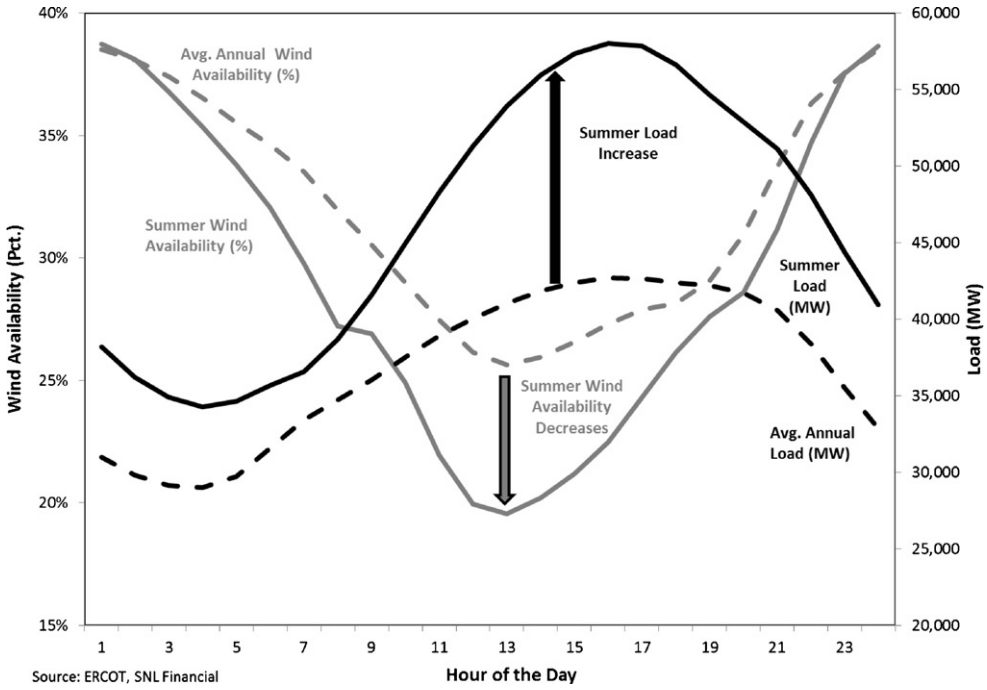

Figure 5: Summer Season and Annual Daily Wind Generation and Load Patterns

production pattern not only is volatile and unpredictable, but even more significantly, has low economic value. Rather than displacing high-variable-cost fossil generating resources used to meet peak demand, wind generation's observed availability peaks when electricity demand is lowest. As a result, wind generation tends to displace low-variable-cost generation or simply forces baseload generators to pay greater amounts to inject power onto the grid because the units cannot be cycled cost-effectively. The low economic value of wind power is comparable to the government paying farmers to plow under high-value crops in order to plant low-value ones, or even weeds.

Second, as with all subsidies, subsidized wind generation distorts electric markets by artificially lowering electric prices in the short run, but leads to higher prices in the long run. This imposes economic harm on competitive generators and consumers, thus reducing economic growth.

Third, because geographic dispersion of wind resources does not address inaccurate forecasts of wind availability, additional fossil generating resources are required to maintain system reliability. Moreover, geographic dispersion requires billions of dollars to be spent on additional transmission lines. These costs, along with most of the system integration costs, are socialized across all grid customers, that is, borne by all generators and, ultimately, consumers. In other words, wind generation imposes external costs on other market participants.

After 35 years of direct and indirect subsidies, there is no economic rationale for continued subsidization of wind generation. At the federal level, direct subsidies, such as the federal PTC, should not be continued. State-level subsidies, whether feed-in tariffs established by state regulators or statutory RPS mandates, further exacerbate market distortions and raise electricity prices, again to the detriment of consumers.

Ultimately, continued subsidization of wind generation simply rewards the few at the expense of the many. Given a massive federal debt and anemic economic recovery, this type of pernicious redistribution cannot be justified.&

Endnotes:

1. More recently, payments to the wind industry have increased still further with billions of dollars in additional monies paid-out as part of

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the $831 billion American Recovery and Reinvestment Act of 2009 (ARRA).

2. M. Sherlock, CRS. ''Impact of Tax Policies on the Commercial Application of Renewable Energy Technology,'' Statement Before the House Committee on Science, Space, and Technology, Subcommittee on Investigations and Oversight & Subcommittee on Energy and Environment, April 19, 2012, p. 3.

3. The reasons why are discussed in the next section.

4. The ''infant industry'' argument historically was used to justify protection of domestic firms from international trade. It was first developed by Alexander Hamilton at the beginning of the nineteenth century. A classic article discussing why infant industries should not be protected is Robert Baldwin, ''The Case Against Infant Industry Protection,'' Journal of Political Economy 75 (1969), pp. 295–305.

5. Arguments that subsidies account for external costs incorrectly assume that the effects of subsidies and taxes are equivalent. They are not. See William Baumol and Wallace Oates, The Theory of Environmental Policy, 2d ed., (Cambridge: Cambridge University Press 1988). See also, Daniel Dodds and Jonathan Lesser, ''Can Utility Commissions Improve on Environmental Regulations,'' Land Economics 70 (1994), pp. 63–76.

6. There is an extensive literature on the effects of subsidies in agriculture, energy, housing, environmental quality, and so forth. General discussions on the impacts of subsidies on markets can be found in any intermediate microeconomics textbook.

7. Equivalently, the marginal cost of cycling the plant is greater than the variable operating cost. Hence, it is economically rational to continue operation.

8. Some argue that price suppression ''benefits'' consumers. While subsidies can reduce market prices in the very short-run, markets are dynamic. Thus, as competitors are driven out, prices increase. Moreover, the threat of intervention raises the expected costs of market entry, leading to higher long-run market prices than would prevail in the absence of subsidies. For a discussion of subsidies and price suppression in organized capacity markets, see Briggs, Robert, and Andrew N. Kleit, Resource Adequacy and the Impacts of Capacity Subsidies in Competitive Electricity Markets, Working Paper, Dept. of Energy and Mineral Engineering, Pennsylvania State University, Oct. 22. 2012. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2165412.

9. This value is based on a federal corporate tax rate of 35%.

10. NREL, Eastern Wind Integration and Transmission Study, NREL/SR-550-47086, Revised February 2011. http://www.nrel.gov/docs/fy10osti/47086.pdf.

11. This value is based on total wind generation of just over 28.2 million MWh in ERCOT in 2011. According to the US Energy Information Administration, total wind generation was about 120 million MWhs in 2011.

12. Public Utilities Commission of Texas, Competitive Renewable Energy Zone Program (CREZ) Oversight, CREZ Progress Report No. 8, July 2012, p. 6. http://www.texascrezprojects.com/page2960039.aspx.

13. Forbes, Kevin, Marco Stampini, and Ernest Zampelli, ''Are Policies to Encourage Wind Energy Predicated on a Misleading Statistic?'' The Electricity Journal 25 (April 2012), pp. 42–54.

14. Source: SNL Financial. Data through August 31, 2012.

15. We defined the ''Winter'' season contiguously. Thus, for example, Winter 2012 is defined as the three months December 2011 through February 2012.

16. In ERCOT, the correlation coefficient between hourly wind availability and annual hourly loads is -0.83. The correlation coefficient for the Summer season is -0.74.

17. We used wind capacity data as published by SNL Financial, which provided wind capacity installed in each month of the 44-month analysis period. The capacity used to calculate wind availability in month m was the amount of reported capacity installed at the end of month m – 1.

18. SPP, Independent Market Monitor, 2011 State of the Market, July 9, 2012, pp. 59–60. The Independent Market Monitor reports that similar wind availability patterns—decreasing availability as load increased—were observed in the three previous years.

19. The median was selected as a more representative planning value for the data. Consider a simple (albeit extreme) example: suppose wind availability was 0% on nine of the ten days, but 100% on the 10th day. In that case, the median availability would be 0% and the average availability would be 10%. However, system planners who assumed 10% wind availability each day in order to schedule generating resources would have to rely on replacement generation on nine of the days, and be forced to back down generation on the 10th. In contrast, using the median availability, system planners would only have to back down generation on the 10th day.

20. The correlation coefficient between average annual hourly wind availability and average annual hourly load is -0.83. The correlation coefficient for the Summer season is -0.74.

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