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The cost of wind power variability

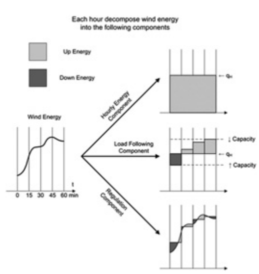
Warren Katzenstein*, Jay Apt

Carnegie Mellon Electricity Industry Center, Department of Engineering and Public Policy and Tepper School of Business, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA

HIGHLIGHTS

- ► A new metric for evaluating the cost of wind power variability is presented.
- ► In ERCOT, wind plants with higher capacity factors cost a system less to integrate.
- ► The marginal benefit of interconnecting wind plants in ERCOT decreases rapidly.
- ► Integration cost depends more on power produced than on ancillary service prices.

GRAPHICAL ABSTRACT



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ABSTRACT

We develop a metric to quantify the sub-hourly variability cost of individual wind plants and show its use in valuing reductions in wind power variability. Our method partitions wind energy into hourly and sub-hourly components and uses corresponding market prices to determine variability costs. We use publically available 15-min ERCOT data, although the method developed can be applied to higher time resolution data if available. We do not estimate uncertainty costs though our metric can separate integration costs into variability and uncertainty components. The mean variability costs arising from 15-min to 1-h variations (termed load following) for 20 ERCOT wind plants was \$8.73 ± \$1.26 per MWh in 2008 and \$3.90 ± \$0.52 per MWh in 2009. Load following variability costs decrease as capacity factors increase, indicating wind plants sited in locations with good wind resources cost a system less to integrate. Twenty interconnected wind plants had a variability cost of \$4.35 per MWh in 2008. The marginal benefit of interconnecting another wind plant diminishes rapidly: it is less than \$3.43 per MWh for systems with 2 wind plants already interconnected, less than \$0.7 per MWh for 4–7 wind plants, and less than \$0.2 per MWh for 8 or more wind plants.

1. Introduction

Wind power is quickly becoming a significant source of energy in the United States. It had an average annual growth rate of 28% over the past decade and supplied 1.3% of the United States' energy in 2008 (EIA, 2010). However, wind is a variable source of power and increases the operational costs of electricity systems because system operators are required to "secure additional operating flexibility on several time scales to balance fluctuations and uncertainties in wind output" (Northwest Power and Conservation Council, 2007). There is interest in using storage technologies or fast-ramping fossil fuel generators, called flexible resources, to mitigate wind power variability and decrease the costs of integrating wind power into electrical systems (Denholm, 2005; Hittinger et al., 2010; Korpass et al., 2003).

Previous research and wind integration studies performed by Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) have estimated that the cost of integrating wind power ranges from \$0.5 to 9.5 per MWh for wind penetration levels ranging from 3.5 to 33% (Wiser and Bolinger, 2008). Note that integration costs are comprised of variability costs (the

* Corresponding author. Tel.: +1 510 891 0446; fax: +1 510 891 0440.
E-mail addresses: warren.katzenstein@dnvkema.com, warren.katzenstein@kema.com (W. Katzenstein).

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continuously changing output of a wind plant) and uncertainty costs (the difficulty in predicting a wind plant's output at any given point of time in the future). Traditionally wind integration costs are paid by the end-user, but system operators have begun to recover the integration costs of wind energy from wind plants directly. In 2009, Bonneville Power Authority (BPA) introduced a tariff of $5.7 per MWh for wind plants within its system to recover the costs of integrating wind power (BPA, 2009). BPA was the first system to charge wind generators for the integration costs of wind energy and other systems are considered likely to follow suit (Kirby and Milligan, 2006).

Wind plant owners may implement solutions to mitigate both variability and uncertainty costs if they are charged for integration costs. For example, a wind plant will be willing to pay up to the tariff imposed by the system for a solution that completely eliminated the variability it produces. In BPA this would be $5.7 per MWh. Realistically, it is not cost effective to completely firm the power output of a wind plant. The costs of integrating wind power are incurred mainly at hourly and sub-hourly time scales and wind power is variable over time scales of sub-minute to weekly (Northwest Power and Conservation Council, 2007; Smith et al., 2007; Katzenstein et al., 2010; Apt, 2007). Wind plants will seek to use flexible technologies to reduce their variability in the hourly and sub-hourly time scales.

Here we develop a metric to determine the cost of variability of individual wind plants and then show its use in valuing reductions in wind power variability. DeCarolis and Keith state that it should be "possible…to assess the overall cost of wind's intermittency" by "portioning the cost of wind's variability between various markets…and market participants" (DeCarolis and Keith, 2005). Here we present an unbiased method to partition wind energy between hourly and sub-hourly markets and use the corresponding market prices to determine the cost of variability from individual wind plants.

The methods used to estimate the integration costs of bulk wind energy[1] are not suitable to evaluate reductions in wind power variability for individual wind plants. First, all of the integration studies have focused on the net wind energy in a system and not the energy produced by individual wind plants. Second, the integration studies use large complex models that are either proprietary or difficult to replicate and are inappropriate to implement on a small scale. Third, the majority of the studies have focused on future large penetrations of wind energy instead of current levels.

There are additional advantages to estimating the variability cost of individual wind plants instead of the net wind power in a system. First, doing so provides a method to determine cost effective solutions to reduce wind power variability. Second, it is important to determine if all wind plants in a system equally contribute to the wind integration costs or if there are a few wind plants sited in poor locations that are causing the majority of the incurred costs. Finally, system operators may be able to prioritize wind plant projects in their interconnection queues to minimize their integration costs for wind energy.

2. Data

We use 15-min time sampled wind power data from 20 ERCOT wind plants in 2008 and 2009. In addition, we use 15-min ERCOT balancing energy service (BES) price data and hourly load following and regulation capacity price data for years 2004 through 2009. The locations of the 20 ERCOT wind plants are plotted in Fig. A1 in Appendix A. Figs. A2 through A7 in Appendix A are box plots of the ERCOT ancillary service prices for years 2004 through 2009.

3. Methods

Our method partitions all of a wind plant's energy among the suite of markets available. We first describe a generalized formulation of this principle that is representative of the electricity markets in the United States and then present a metric specific to ERCOT. The 3 types of services a generator in a United States electricity system can provide are energy, capacity, and ancillary. Each service is necessary to maintain a functioning electricity system although each electricity system in the United States does not offer competitive markets for all of the services described.

Providing energy is the primary service of an electricity system, accounting for 70–95% of the wholesale cost of electricity (ISO New England, 2009; PJM, 2009; Potomac Economics, 2009). Energy markets are typically operated on an hourly basis and, depending on the ISO, a generator can submit bids for each hourly interval in day-ahead markets, hour-ahead markets, or real time markets. System operators accept enough generator bids to meet the predicted load for a given hour plus a specified reserve margin. Generators whose bids are accepted are required to supply power at the specified level for that hour.

From a system point of view, capacity markets ensure a system has enough generators it can call upon to meet their maximum load plus a reserve margin. From a generator's point of view, energy markets are designed for generators to recover their variable costs while capacity markets are designed for generators to recover their fixed costs. Capacity markets are typically longer term markets that operate on a yearly basis.

Ancillary services are a suite of products designed to handle the variability present in an electrical network. Variability exists in electricity grids due to fluctuations in load, transmission, and generation. The nature of electrical networks and the lack of cost effective storage in electricity systems mean that the exact amount of electricity produced must be consumed if the system is to remain stable. Small deviations can be tolerated but need to be corrected according to the standards set by the North American Electricity Reliability Council (NERC). The suite of ancillary services are traditionally defined as load following, regulation, energy imbalance, spinning reserve, supplemental reserve, frequency control, voltage control, nonoperating reserve, and standby service (Hirst and Kirby, 1997).

Renewable energy credit (REC) markets value the additional benefits renewable energy generators add to a system. The primary benefits of renewable energy are that it is a zero emissions source and that it satisfies policy goals mandated by over 29 states. The additional yet less tangible benefits are a decreased dependence on foreign energy sources, an increase in portfolio diversity, and a hedge against future fuel prices. Typically, 1 renewable energy credit is the environmental and social value of 1 MWh of renewable energy.

From a system operator's point of view, the value of energy from a wind plant is the sum of the wind plant's energy, capacity, REC, and ancillary service benefits and its ancillary service costs. The costs of incorporating wind power into a system can be classified based on the 2 defining characteristics of wind power: uncertainty and variability (Chang et al., 2010). Systems incur costs due to wind power's uncertainty because system operators can never know with a 100% certainty what the output of a wind plant will be at a given time. The difference between the forecast

[1] The methods used to estimate system wind integration costs vary widely from study to study. Generally, wind integration costs are estimated as the difference between a system's cost of electricity with a given penetration of wind energy and a system's cost of electricity with a non-variable energy proxy in wind power's place (Milligan and Kirby, 2009).

and the actual output of a given wind plant must be eliminated using either hourly energy markets or ancillary services markets. We do not estimate the cost of forecast errors in this paper but note that the cost of forecast errors can be included in our metric.

Wind power variability, the fact that the output of a wind plant is constantly changing, also causes systems to incur costs. Any change in the power output of a wind plant must be compensated by another source in the system. This source could be other wind plants, loads, conventional generators, or energy storage. If conventional generators are used, the inefficiencies suffered due to changing its power level are costs directly related to wind power. We note that wind power variability also changes the loading of transmission lines and we do not attempt to calculate the resulting changes in transmission profitability.

We estimate the cost of wind power variability in ERCOT by using an optimization model that partitions the power output of a wind plant between hourly energy and ancillary service markets (Fig. 1). For each hour, we determine a constant amount of a wind plant's energy to partition to the hourly energy market (q_h). As we explain below, the hourly energy level is the decision variable in our optimization model. We remove the hourly energy component from the wind signal and then determine the residual ancillary services required. For the example in Fig. 1 we assume a simplified ancillary services market, representative of ERCOT's ancillary services, that consist of load following and regulation markets. Regulation is the ancillary service that handles rapid fluctuations on time scales of minutes and load following is the ancillary service that handles larger fluctuations on time scales of 15 min. We first determine the amount of load following capacity (both up and down capacity) and energy needed and then determine the amount of regulation capacity (both up and down capacity) and energy required. We do not attempt to calculate the capacity or REC benefits of wind plants because they do not affect

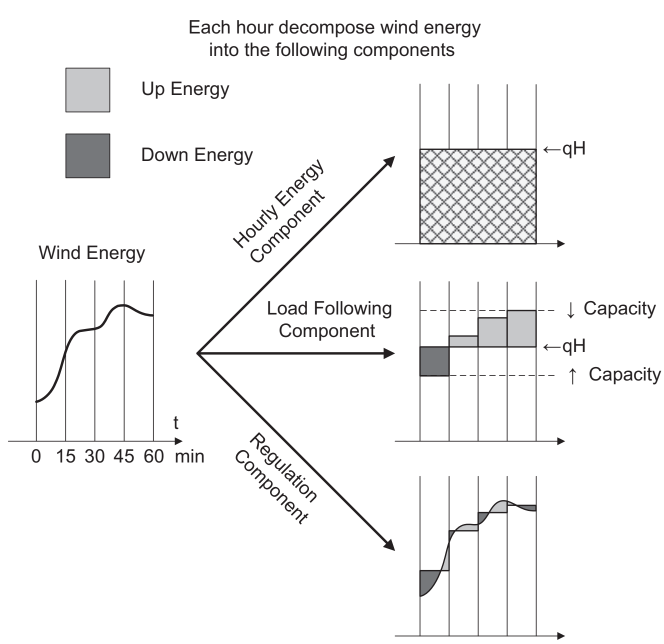

Fig. 1. Conceptual diagram of how we partition wind energy into hourly energy, load following, and regulation components. The hourly energy component (q_h) is the decision variable in our optimization algorithm and is set at the level that minimizes the total costs of the load following and regulation components. The cost for the load following and regulation components are comprised of energy and capacity costs. The amount of capacity procured each hour is the maximum amount of up and down load following and regulation capacity needed. The amount of energy procured is the absolute sum of the energy used in load following and regulation to cover deviations from the hourly energy schedule (q_h).

the variability costs of wind plants. Only the energy portioned to the hourly energy market affects the estimated variability cost.

Eq. (1) is the simplified formulation of the variability cost of wind energy for wind plants in ERCOT based on the portioning method represented in Fig. 1. We use Eq. (1) as our objective function in our optimization model. We calculate only the load following component of the ancillary service cost of wind energy because we were able to obtain only 15-min time-resolved wind energy data for 20 ERCOT wind plants. The yearly variability cost of energy from a wind plant is the sum of its hourly costs.

$$\text{Hourly Variability Cost} = \sum_{k=1}^{4} \varepsilon_k P_k + P_{UP}\min(\varepsilon_k) + P_{DN}\max(\varepsilon_k) \tag{1}$$

and

$$\text{Yearly Variability Cost} = \sum_{i=1}^{8760} \text{Hourly Cost}_i$$

where P_k is the sub-hourly price of energy, P_{UP} is the sub-hourly price for up regulation capacity, P_{DN} is the sub-hourly price for down regulation capacity, q_H is the amount of firm hourly energy partitioned, $\varepsilon_k = W_k - q_H$, the amount of sub-hourly energy per time period k; minimized or maximized per terms in Eq. (1).

In formulating Eq. (1), we make 2 key assumptions. The first is that each wind plant is a price taker and does not affect market prices for energy or ancillary services. The second is that deviations from the hourly energy level are costs and are to be avoided.

The variability cost of wind energy, as calculated from Eq. (1), is dependent on what value is chosen for q_H (the hourly energy component). In order to create an unbiased cost metric, each hour we use the set of energy and ancillary services prices and wind power data to determine the q_H that minimizes the variability cost. Thus, we are estimating what the variability cost of wind plant's in ERCOT was in a given year, and not attempting to predict what it will be. Eq. (2) is the formulation of the optimization model for our metric. Constraints on the optimization problem are:

1. The sum of energy components in each 15-min interval must equal the energy produced by the wind plant in the 15-min interval.
2. The maximum ancillary services capacity during the hour plus the hourly energy component is equal to the maximum wind power produced during the hour.
3. The hourly energy component plus the minimum ancillary services capacity (assumed to be negative) during the hour is equal to the minimum wind power produced during the hour.

We determine q_H, ε_k, $\max(\varepsilon_k)$, and $\min(\varepsilon_k)$ for each hour (using the Matlab fmincon function to solve the linear optimization problem).

$$\text{Minimize } f(q_H,\ \varepsilon_1,\ \varepsilon_2, \ldots,\ \varepsilon_4) : \sum_{k=1}^{4} \varepsilon_k P_k + P_{UP}\max(\varepsilon_k) + P_{DN}\min(\varepsilon_k) \tag{2}$$

where $\varepsilon_k = W_k - q_H$, $k = 1{:}4$

Subject to

1) $h_k(q_H, \varepsilon_k) : q_H + \varepsilon_k = W_k$, $k = 1{:}4$
2) $g(q_h, \max(\varepsilon_k)) : q_h + \max(\varepsilon_k) = \max(W_k)$, $k = 1{:}4$
3) $d(q_h, \min(\varepsilon_k)) : q_h + \min(\varepsilon_k) = \min(W_k)$, $k = 1{:}4$

We use ERCOT's balancing energy service (BES) as the prices for P_k. Each hour for P_{UP} we use the minimum of ERCOT's up-regulation price for capacity and responsive reserve price for capacity. Each hour for P_{DN} we use the minimum of ERCOT's down-regulation price for capacity and responsive reserve price for capacity. We use the minimum of the prices because we are trying to find the minimum variability cost of each wind plant in ERCOT.

4. Results

Fig. 2 displays the estimated variability costs of 20 ERCOT wind plants sorted by their capacity factors for 2008. The mean variability cost was $8.73 per MWh (16% of the mean BES price of electricity in ERCOT in 2008) with a standard deviation of $1.26 per MWh. As the capacity factor increases, the variability cost decreases, indicating wind plants sited in locations with good wind resources cost a system less. In 2008, the range of costs for wind plant variability was $6.79 to $11.5 per MWh. We do not observe a dependence of variability costs on the nameplate capacity of a wind plant, although a larger data set with a larger range of nameplate capacities is needed to make a conclusive statement.

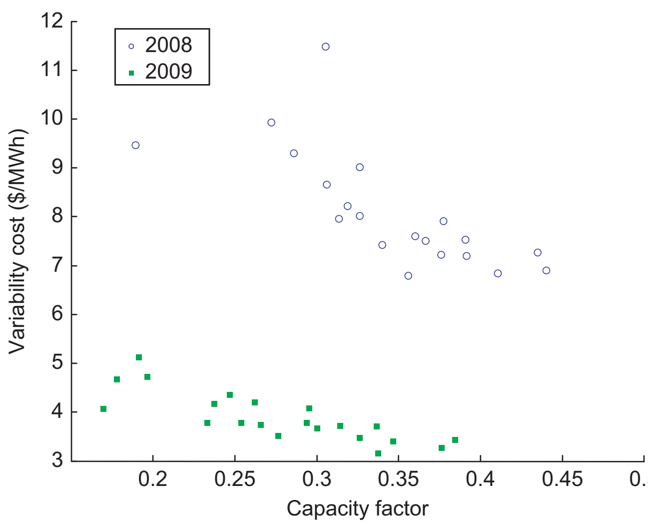

Fig. 2. Estimated variability costs for 20 ERCOT wind plants versus their capacity factors for 2008 (upper group of points) and 2009 (lower points). The variability cost of wind power decreases as the capacity factor of a wind plant increases.

Fig. 2 also displays the estimated variability costs of 20 ERCOT wind plants sorted by their capacity factors for 2009. The mean variability cost in 2009 was $3.90 per MWh (12% of the mean BES price of electricity in ERCOT in 2009) with a standard deviation of $0.52 per MWh. The same relationship of declining variability costs versus capacity factor is present. In 2009, the range of costs for wind plant variability was $3.16 to $5.12 per MWh. The estimated variability costs for 2009 were substantially lower than the variability costs estimated for 2008 and are a direct result of lower ancillary service prices in 2009 compared to 2008 (see Figs. A8 and A9 in Appendix A).

Variability costs decline as the capacity factor increases for 2 reasons. First, we measure variability costs per MWh of wind energy produced and the amount of energy partitioned to ancillary services does not grow as fast as the amount of energy produced by the wind plant. Second, wind turbines produce power from wind based on a cubic power curve (see Fig. A10 in Appendix A). As the capacity factor of a wind plant increases, it produces more of its power in region 3 of Fig. A10 in Appendix A where the turbines produce their maximum power. Other power curves are not as smooth as the one depicted but nonetheless in region 3 there is less of a chance for significant changes in power output from 1 min to the next compared with regions 1 and 2.

We use this variability cost metric Eq. (1) to value the reductions in wind plant variability when wind plants are interconnected to each other. Previous research has shown that wind power variability is reduced as wind plants are interconnected to each other with transmission lines (Katzenstein et al., 2010). We compare the variability costs of individual wind plants to the variability cost of 20 interconnected wind plants. Fig. 3 shows how the variability costs of wind energy are reduced as wind plants are interconnected. In Fig. 3, we selected the wind plants with the highest, median, and lowest variability costs and then interconnected the remaining 19 wind plants to them based on distance (closest to farthest) and calculated the variability cost after each interconnection.

In 2008, 20 wind plants interconnected to each other with transmission lines of infinite capacity (sometimes referred to as a

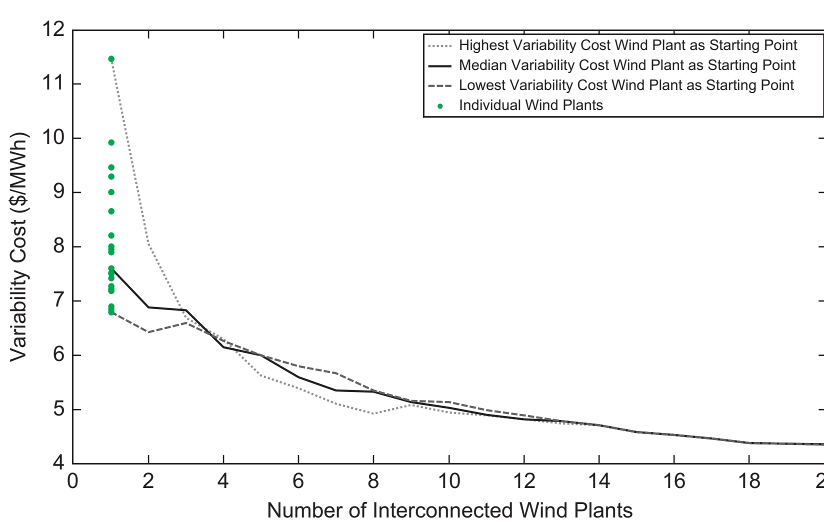

Fig. 3. Variability costs of wind energy decrease as wind plants are interconnected. Interconnecting 20 wind plants together produces a mean savings of $3.76 per MWh compared to the 20 individual ERCOT wind plants (green dots). Only 8 wind plants need to be interconnected to achieve 74% of the reduction in variability cost. Three cases are shown where the highest, median, and lowest variability cost wind plants were used as starting points and the remaining 19 wind plants were interconnected to them based on distance (closest to farthest). Note we calculate the marginal benefit of X interconnected wind plants as the difference in variability costs of $X+1$ interconnected wind plants and X interconnected wind plants. (For references to color in this figure legend, the reader is requested to refer the web version of this article.)

copper plate interconnection) have a variability cost of $4.35 per MWh (8.1% of the mean BES price of electricity in ERCOT; see Table A1 in Appendix A). Interconnecting 20 wind plants produces a mean savings of $3.76 per MWh compared to the variability costs of individual ERCOT wind plants. A minimum savings of $2.44 per MWh and a maximum savings of $7.15 per MWh are achieved. The majority of the reductions in variability cost are achieved quickly as only 8 wind plants need to be interconnected to obtain the maximum reductions in variability costs. Our estimated load following variability costs for interconnected wind plants are comparable to the load following costs previously determined in integration studies and BPA's integration tariff (Acker, 2007; BPA, 2009; EnerNex, Corporation, 2007; EnerNex Corporation and Idaho Power Company, 2007; PacifiCorp2007; Puget Sound Energy, 2007).

As seen in Fig. 4, the marginal benefit of interconnecting another wind plant decreases rapidly as more wind plants are interconnected. We calculate the marginal benefit of X interconnected wind plants as the difference in variability costs of $X+1$ interconnected wind plants and X interconnected wind plants. The marginal benefit of interconnecting another wind plant is less than $3.43 per MWh for 1 wind plant already interconnected, less than $1.36 per MWh for 2 wind plants, less than $0.7 per MWh for 3–7 wind plants, and less than $0.19 per MWh for 8 or more wind plants. If the worst case (Highest Variability Cost Wind Plant as Starting Point) is excluded, the marginal benefit of interconnecting another wind plant is less than $0.72 per MWh for 1 wind plant already interconnected, less than $0.05 per MWh for 2 wind plants, less than $0.68 per MWh for 3–7 wind plants, and less than $0.19 per MWh for 8 or more wind plants. We recognize that this calculation is approximate, since the ERCOT-wide prices may not be appropriate for weakly-connected wind plants.

We calculated the marginal reduction in variability costs for ERCOT wind energy for the 20 possible cases of connecting a 20th wind plant to 19 already interconnected wind plants (Fig. A11 in Appendix A). The mean reduction in variability costs was very small as expected from an inspection of Fig. 3, $0.03 per MWh, with a standard deviation of $0.06 per MWh. The maximum reduction achieved was $0.09 per MWh. Interestingly, there were 3 wind plants that increased ERCOT's variability cost when they were interconnected last (the greatest increase was $0.13 per MWh). Other regions may experience different costs due to wind characteristics; costs may increase if ancillary service costs rise from the 2008 levels used here due to increased wind

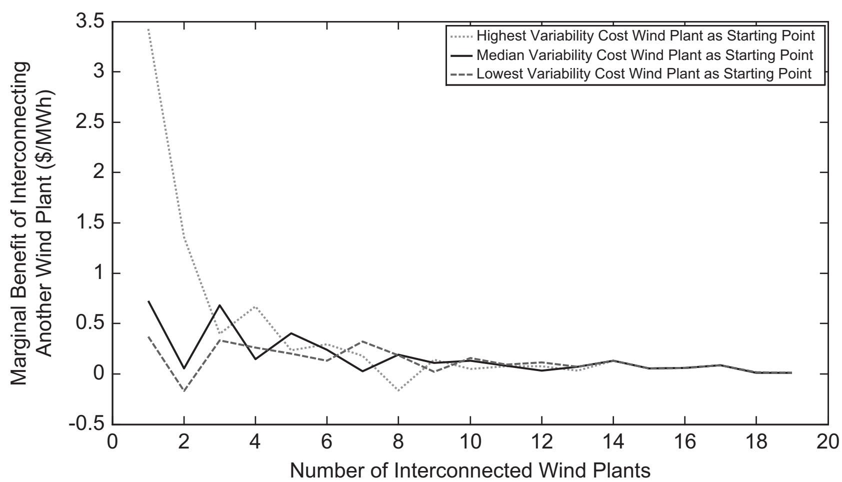

Fig. 4. Marginal benefit of interconnecting an additional wind plant in reducing variability costs. For example, with 1 wind plant interconnected to a system, the maximum marginal benefit of interconnecting another wind plant is $3.43 per MWh.

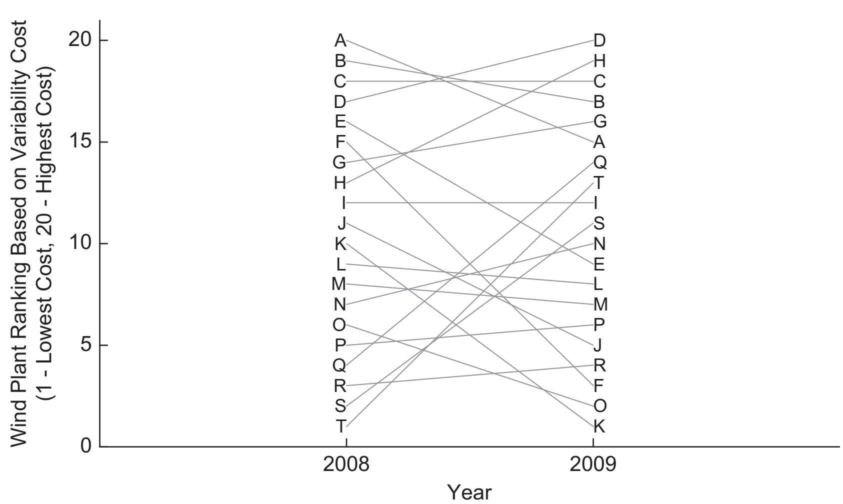

Fig. 5. The change in wind plant ranking of variability cost from 2008 to 2009. For 2008 (left side), we ranked the 20 ERCOT wind plants based on their estimated variability costs and assigned the labels A through T to the 20 wind plants, with A being the wind plant with the highest variability cost and T being the wind plant with the lowest variabilty cost. For 2009 (right side), we reordered the wind plants based on their variability costs but kept the labels the same.

penetration. If a system recovers integration costs through a flat tariff then equity considerations by system planners will raise the question "should all wind plants pay the increased integration costs if poorer performing wind plants are interconnected to the system?" This is particularly important in regions with aggressive renewables portfolio standards.

Fig. 5 displays how the rankings of wind plants based on their variability costs change from 2008 to 2009. For 2008, we ranked the 20 ERCOT wind plants based on their estimated variability costs and assigned the labels A through T to the 20 wind plants, with A being the wind plant with the highest variability cost and T being the wind plant with the lowest variability cost. For 2009, we reordered the wind plants based on their variability costs. The labels were kept the same in order to track how the rankings changed. The gray lines are visual guides to help the reader track the changes.

As seen in Fig. 5, ERCOT wind plants significantly change their rankings from 2008 to 2009. Three of the 4 least cost wind plants in 2008 become 3 of the 10 wind plants with the highest variability cost. Eight of the 20 wind plants change their rank by 2 spots or less. This indicates some wind plants are persistent in their variability costs while others vary significantly year to year. A longer data set is required to determine conclusively if there are wind plants that have consistent variability costs. The significant reordering of wind plants from 2008 to 2009 is because of the change in power output of the wind plants from 2008 to 2009. Our results are insensitive to yearly changes in ancillary service prices (see Appendix A).

5. Conclusions

We have developed a cost metric capable of estimating the variability cost of individual wind plants by decomposing wind energy into hourly and sub-hourly components and costing them using observed sub-hourly ancillary service prices. The metric is applicable to variability at all time scales faster than hourly, and can be applied to long-period forecast errors. We use publically available data at 15-min time resolution to apply the method to ERCOT, the largest wind power production region in the United States. Our metric produces estimates for variability costs that are within the range of integration costs estimated by numerous studies produced by the major electricity market operators in the United States (for example, Fig. 39 of Wiser and Bolinger, 2010). This metric appears to have general applicability without requiring assumptions that may apply to only a single market or wind penetration level. The metric also is transparent and easily applied, without the need for complex proprietary system models.

Wind plants with higher capacity factors have lower variability costs and cost a system less to integrate. We find that the relative ranking of wind plants based on variability costs is dependent on the wind power produced from the wind plants and not on ancillary service prices.

We have also provided a method to value reductions in wind power variability. Interconnecting 20 wind plants produced a mean savings of \$3.76 per MWh. Our cost metric can be used to evaluate the cost-effectiveness of storage solutions to mitigate wind power variability. Systems can also use these methods to determine if building long transmission lines to good wind sites is cost-effective. Our estimates for wind power variability costs do not include the costs of smoothing wind's variability at time scales shorter than 15-min (we had only 15-min data available). Future work should extend this analysis to examine the sub-15 min wind power variability costs. In addition, future work should examine how sub-hourly variability costs (those computed here) compare to costs due to forecast error (1 h and longer).

System operators will be called upon to determine if the cost of variability from wind plants should be socialized or assigned to wind plants. Currently in most systems rate payers provide a subsidy to the wind industry by paying for the integration costs of wind energy. BPA, on the other hand, determined the wind plants in their system should pay for the cost of integrating their power and is recovering wind integration costs ex-ante with a flat tariff applied equally to all wind plants in its system. If other systems follow BPA's example, system operators will have to decide if they want to recover wind integration costs ex-ante or ex-post. By recovering integration costs ex-ante, systems can provide wind plants with more certainty on how much they will have to pay over the course of a year, however wind plants may then pay more (or less) than what it actually cost to integrate their power into a system. By recovering costs ex-post, wind plants will pay each year what it actually cost to integrate their power into a system. Ex-post recovery would inject uncertainty into wind plant financial pro formas and would make it more difficult for wind plants to obtain financing.

System operators must also determine whether a flat tariff (such as BPA's tariff) or a capacity factor based tariff indexed to the price of electricity is appropriate to recover integration costs. Fig. 2 supports a capacity factor based tariff indexed to the price of electricity. Variability costs decline as the capacity factor of a wind plant increases so wind plants with higher capacity factors should pay less than wind plants with lower capacity factors. In addition, wind integration costs vary significantly year to year (Figs. A7 and A8) and any tariff should be indexed to the price of electricity to capture this variation. Yet, as Fig. 4 shows, the variability cost of 20 interconnected wind plants is less than the sum of the variability costs of 20 individual wind plants, so even lower capacity factor plants contribute to reduced integration costs (although the marginal benefit of smoothing by interconnection of more than a few plants is minimal). Additionally, systems should offer a reduced tariff to wind plants that actively mitigate their variability to encourage the development of market based solutions to minimize wind power variability.

Finally, if system planners can identify wind plants in their interconnection queues with the highest capacity factors they could take an active approach to decrease their total system costs by giving priority to these projects, if our ERCOT results prove applicable in other areas. While the benefit a wind plant adds to a system is more complicated than just its projected variability cost (for example, transmission costs are important) system planners should have the ability to prioritize projects within their queue based on the benefits they provide. With any non-zero discount

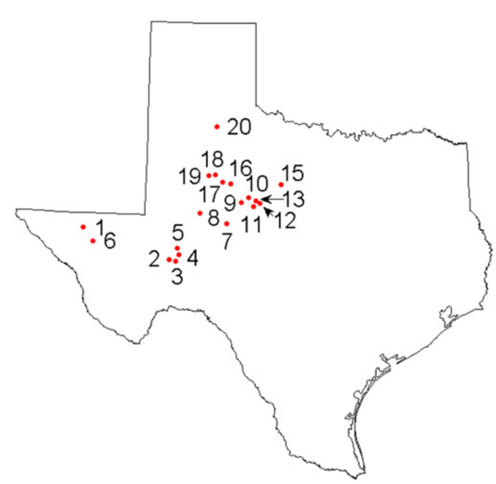

Fig. A1. Location of the 20 ERCOT wind plants in Texas.

rate, the net social costs of interconnecting all the wind plants in a queue will be significantly reduced by optimizing the priority of interconnection for lowest near-term integration costs. Wind plants should also be given priority in the interconnection process if they implement flexible technologies such as storage or dedicated firm generation to mitigate their variability costs.

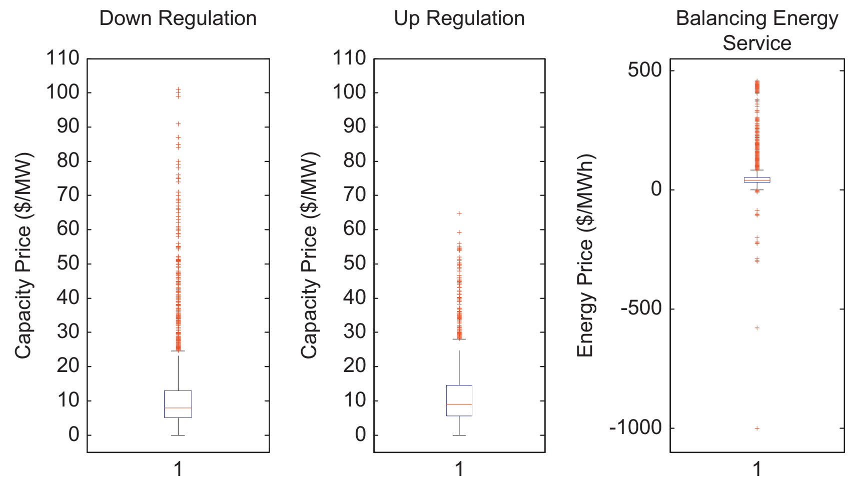

Fig. A2. Box plots for 2004 ERCOT ancillary service prices.

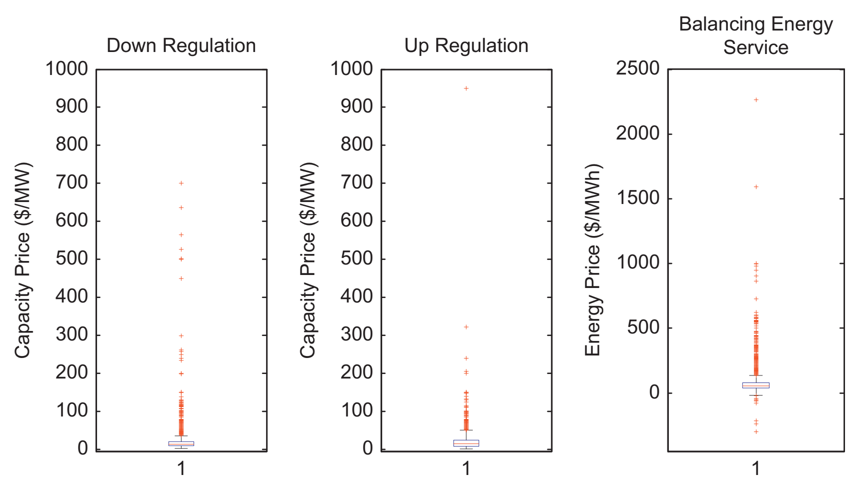

Fig. A3. Box plots for 2005 ERCOT ancillary service prices.

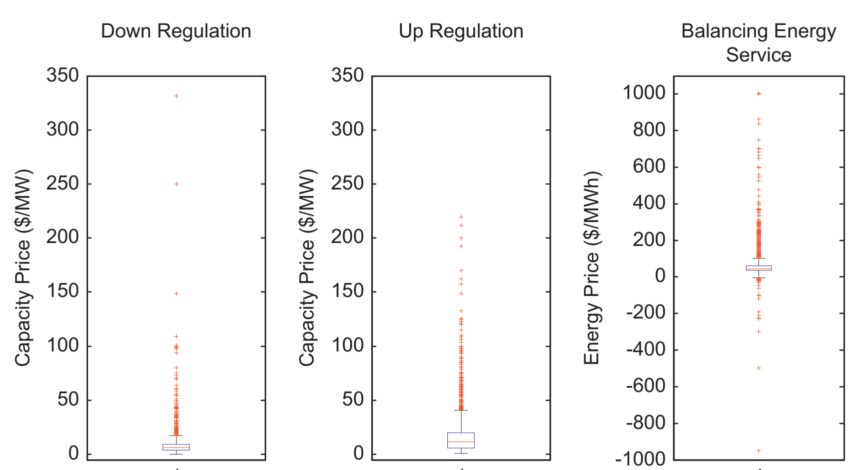

Fig. A4. Box plots for 2006 ERCOT ancillary service prices.

Acknowledgments

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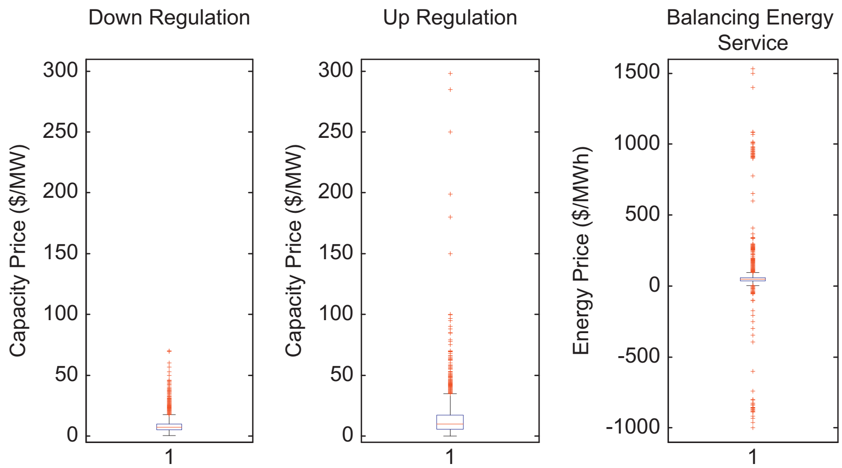

Fig. A5. Box plots for 2007 ERCOT ancillary service prices.

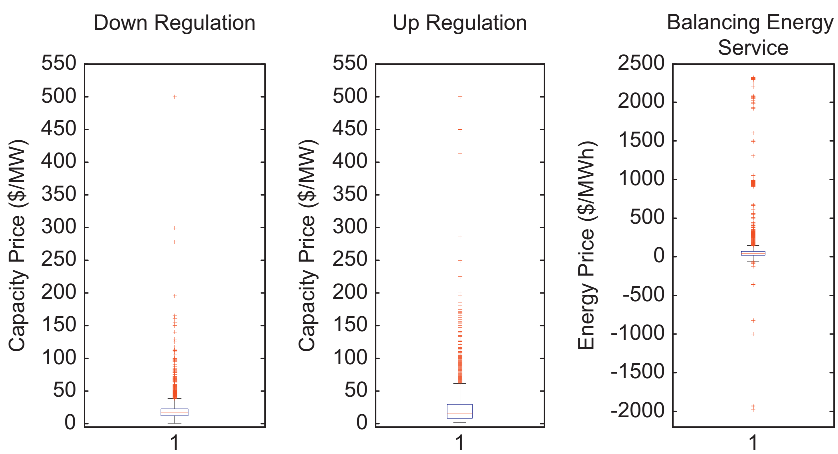

Fig. A6. Box plots for 2008 ERCOT ancillary service prices.

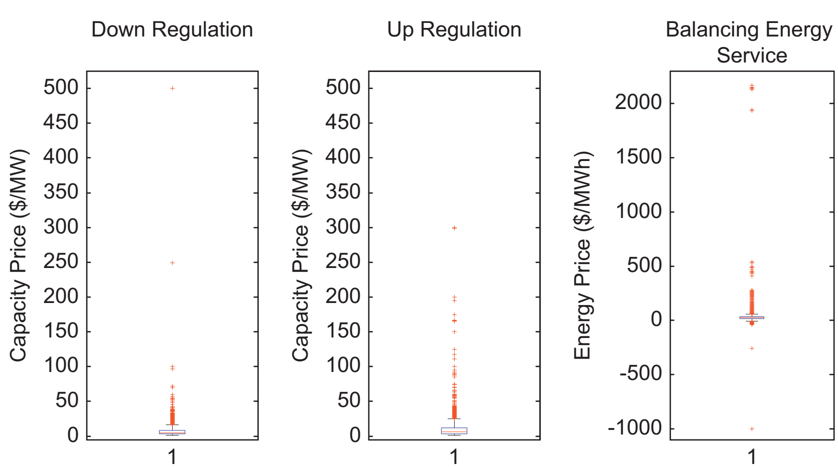

Fig. A7. Box plots for 2009 ERCOT ancillary service prices.

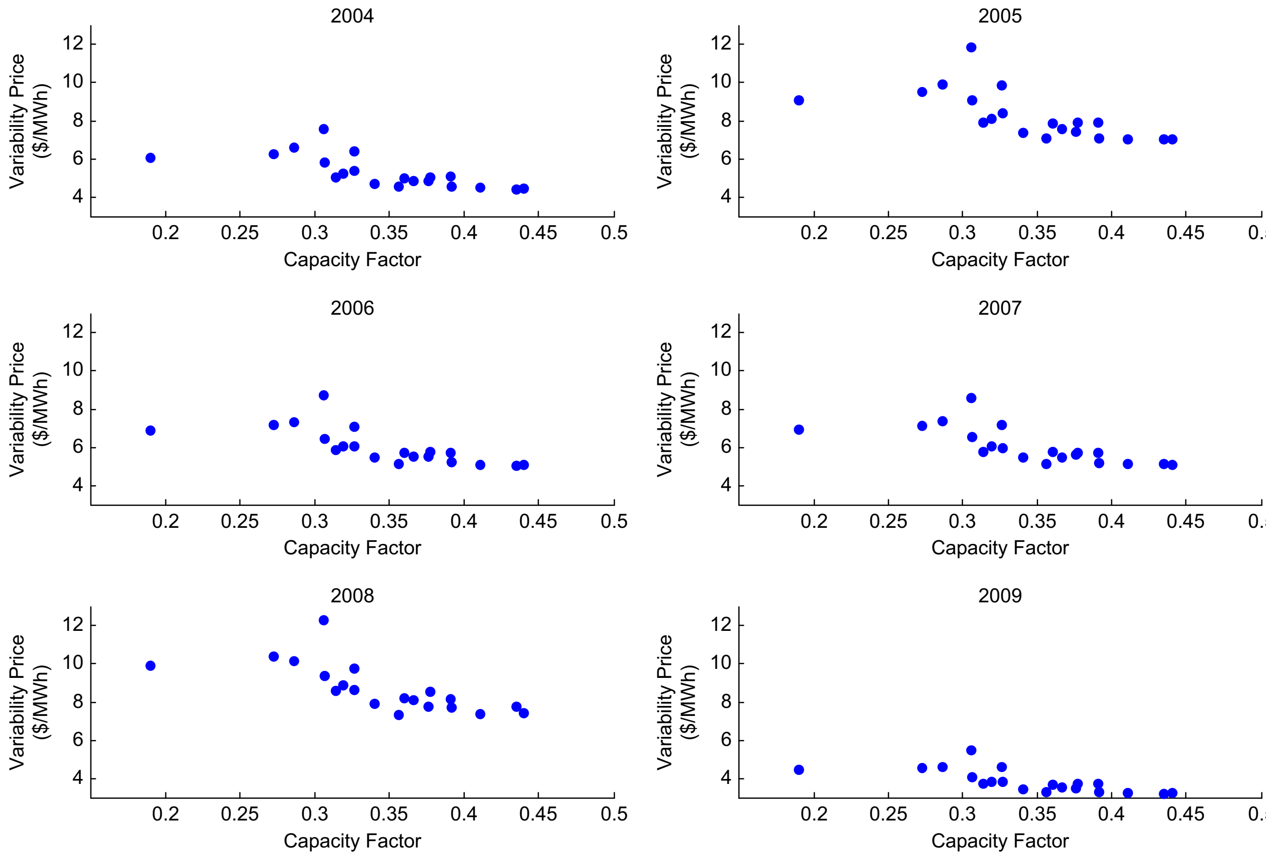

Fig. A8. Sensitivity of our 2008 wind power results to different years of ancillary price data.

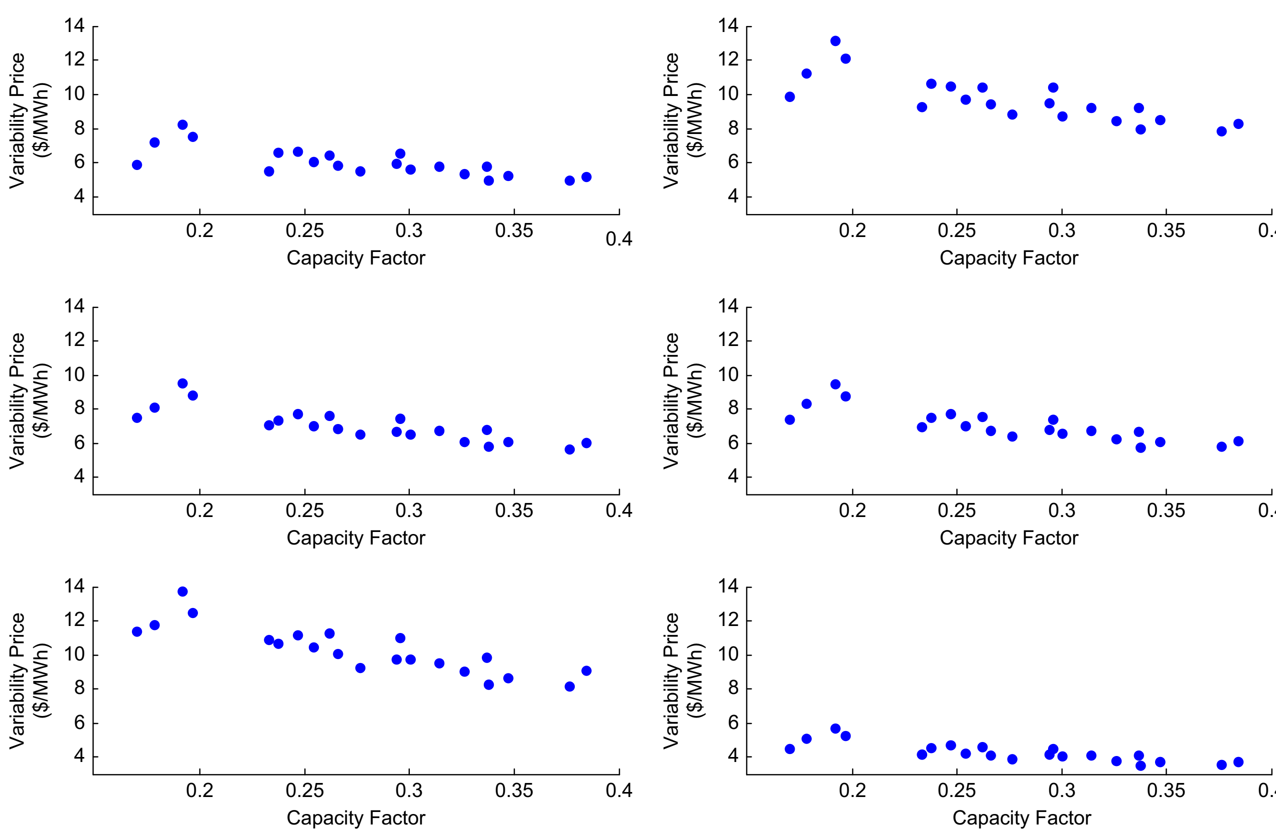

Fig. A9. Sensitivity of our 2009 wind power results to different years of ancillary price data.

the Climate and Energy Decision Making (CEDM) center, created through a cooperative agreement between the National Science Foundation (SES-0949710) and Carnegie Mellon University.

Appendix A

See Fig. A1, Fig. A2, Fig. A3, Fig. A4, Fig. A5, Fig. A6, Fig. A7, Fig. A10, Fig. A11, and Table A1.

The wind power data for the 20 ERCOT wind plants spanned 2008 and 2009 yet the ancillary service prices spanned 2004 through 2009. Each subplot in Fig. A8 displays the estimated variability costs when the 20 ERCOT wind plants in 2008 and the displayed year of ancillary service prices are used as inputs to the cost metric. Fig. A8 shows the sensitivity of our metric to 6 years of varying price signals. Each year the same relationship of declining variability costs as capacity factors increase is seen. The range of results is dependent on the price of the ancillary services each year. Years 2005 and 2008 had the highest ancillary service prices and as a result, our metric estimates the highest variability cost for the 20 ERCOT wind plants for 2005 and 2008. The converse is true for 2009 ancillary service prices. Similar results were obtained using 2009 ERCOT wind data (Fig. A9).

As seen in Fig. A12, a wind plant's rank is insensitive to ancillary price data. In other words, wind plant A, the wind plant with the highest estimated variability cost using 2004 ancillary price data and 2008 wind power data, had the highest variability cost in all 6 years. Fourteen of the 20 wind plants change their rank by 2 spots or less over a 6 yr span. The greatest change is by wind plant T when from 2006 to 2008 it changed 5 spots then returned to its original rank in 2009. This indicates our results are sensitive to the energy output of the wind plants rather than ancillary service prices. Similar results were obtained using 2009 ERCOT wind data (Fig. A13).

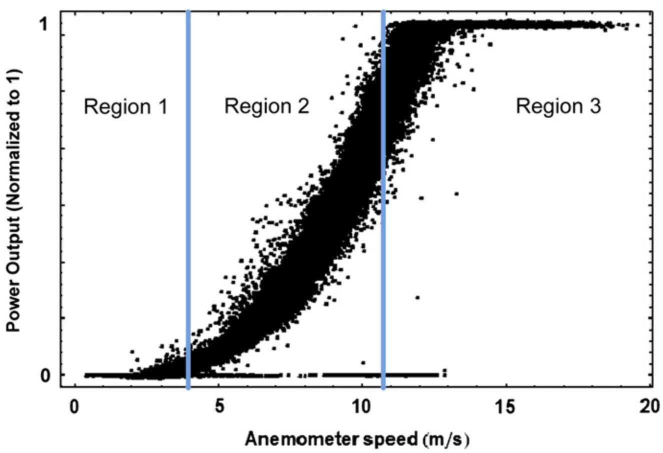

Fig. A10. Actual power curve for a wind turbine.

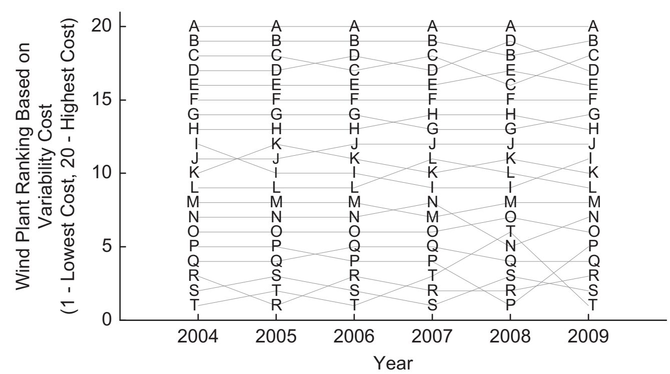

Fig. A12. Change in 2008 wind plant rankings based on variability cost for 6 different years of ancillary service prices.

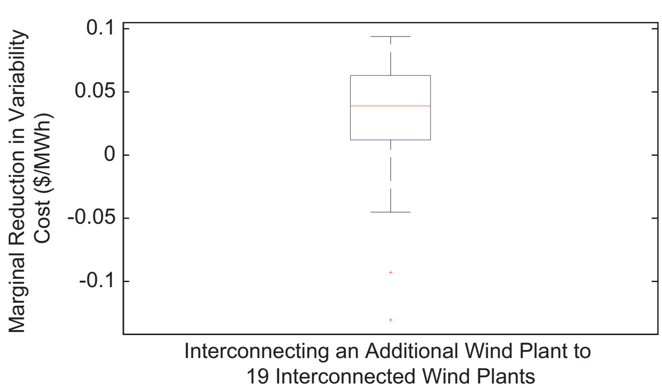

Fig. A11. Box plot of marginal reductions in variability cost for interconnecting a 20th wind plant. All 20 possible cases were estimated.

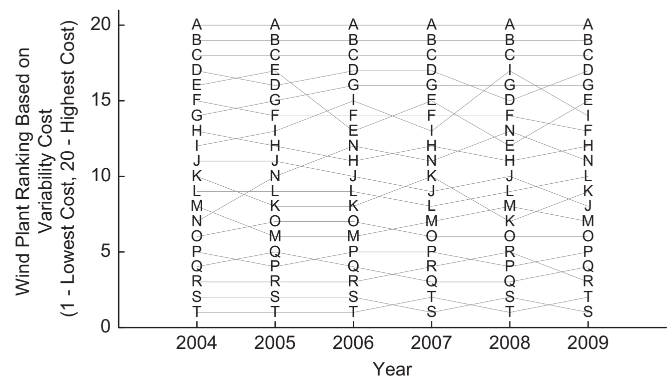

Fig. A13. Change in 2009 wind plant rankings based on variability cost for 6 different years of ancillary service prices.

Table A1
Mean and median values for ERCOT's down regulation (DR), up regulation (UR), and balancing energy service (BES).

Year	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*
Mean DR ($/MW)	11.09481	19.60145	7.961669	8.297936	19.51802	7.251425
Mean UR ($/MW)	11.47404	18.94291	15.24432	13.13814	22.70802	9.701911
Mean BES ($/MW)	41.79429	66.37815	51.35951	52.21617	53.53612	25.77374
Median DR ($/MW)	7.98	13.5	6.19	7.26	16.8	5.01
Median UR ($/MW)	9	14.425	11.555	9.89	15.265	6.03
Median BES ($/MWh)	39.06	55.29	45.02	48.13	49.39	23.08

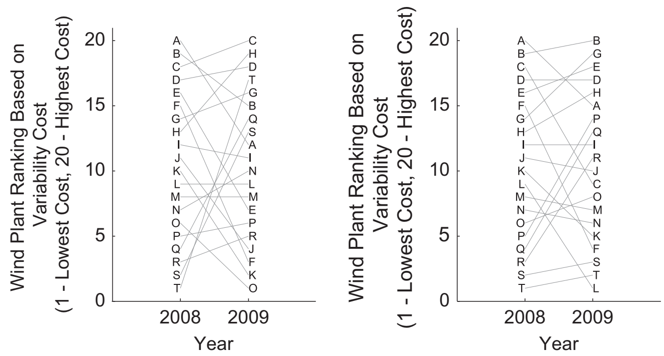

Fig. A14. Change in wind plant rankings when the ancillary price data is held constant. In the left subplot, 2008 ancillary price data was used with 2008 and 2009 wind power data. In the right subplot, 2009 ancillary service prices were used with 2008 and 2009.

Fig. A14 displays the results if the ancillary service prices are kept constant and the ERCOT wind energy data set is varied. Fig. A14 is the sorted variability costs of 2008 ERCOT wind and ancillary price data on the left and 2009 ERCOT wind and ancillary price data on the right. Similar to Fig. A12, the 2008 ERCOT wind data results were sorted by variability costs and labeled A through T with A being the wind plant with the highest variability cost and T being the wind plant with the lowest variability cost. The labels were kept the same for the 2009 wind data but reordered based on the 2009 variability costs.

Compared to Figs. A12 and A13, the ranking of wind plants based on variability costs in Fig. A14 significantly changes order indicating the relative variability costs of wind plants are dependent on the wind data and not the ancillary service price data. In other words, some wind plants produce wind power that costs a system more to integrate than other wind plants and the set of wind plants that do change from year to year. The implications of this result is that a flat tariff, such as the one BPA imposed, is not an unreasonable method to recoup the integration costs of wind energy. Interestingly, about half of the ERCOT wind plants significantly change their rank from 2008 to 2009 while others do not. This indicates some wind plants are persistent in their variability costs while others vary significantly year to year although a longer wind data set is required to determine anything conclusively.

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