The effect of variability-mitigating market rules on the operation of wind power plants

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Abstract

In power systems with many wind generators, market rules have been slowly changing in order to mitigate or internalize the system costs relating to wind variability. We examine several potential market policies for mitigating the effects of wind variability. For each market policy, we determine the effect that the policy would have on the operation and profitability of wind plants, using time series analysis to estimate the actions of profit-maximizing wind generators acting as price takers. We identify policy scenarios that significantly reduce short-term (30-min) wind fluctuations while having little effect on wind plant revenue. For example, in a scenario where the ramp-rate of wind is limited and ramping violations are assigned a small monetary penalty, a loose ramp rate limit (40 % per 15-min period) can reduce 30-min fluctuations by 35 % while reducing wind plant revenue by only 0.2 %. The novel market-based strategies investigated in this work may enable reductions in the overall system cost of wind integration and can be designed so that both wind generators and system operators are better off than under the status quo.

Keywords

Variability Wind power Wind integration Market policy

1 Background

The variability of wind power must be balanced by other system resources in order to be integrated into an electric grid. “Wind integration” includes methods of dealing with the variability of wind across the frequency spectrum, from increased need for frequency regulation to additional reserve requirements. In most electrical grids, these wind integration costs are treated as part of the transmission services and paid by entities other than the wind generators. Transmission system operator costs are normally borne by load-serving entities or by the entire generation base, making the variability of wind a negative externality handled by the remainder of the grid. In many regions, this is not yet an important issue. Most grids have a low penetration of wind, making the system cost of wind integration small in absolute terms. But wind integration costs (per MWh) are predicted to rise quickly with wind penetration [26], and the expected increases in wind generation in the coming decades will greatly increase total wind integration costs to billions of dollars per year in the US [23]. Strategies that reduce the system-wide costs of wind integration should be investigated immediately so that informed policies can be put in place before these costs are encountered.

Several grid operators have altered market rules so that the costs of wind generation are at least in part internalized to wind generators. In some areas, this means exposing wind generators to market prices or requiring wind to bid into the market so that it can be economically curtailed. In other areas, more constraining rules are used, such as ramp-rate limits or required curtailment to produce an operating reserve.

The Bonneville Power Administration (BPA) has introduced a “Wind Balancing Service” and, for the year 2010, charged wind generators a tariff of $1,090 per MW of wind nameplate capacity per month to supply the required balancing services [2, 3]. This works out to around $5.70/MWh (depending upon capacity factor), though BPA originally sought a higher rate that would have charged wind generators approximately $12/MWh, and has been increasing this tariff in each rate adjustment [2, 3, 4, 5].

In the Republic of Ireland, EirGrid requires wind plants to have power control systems that allow them to respond to frequency changes by adjusting their power output. EirGrid occasionally requires wind generators to have a nominal power output slightly lower than their potential power output, producing a small reserve to respond to low frequency events[1] [8]. Wind generators are required to react to frequency changes at a rate of 1 % of nameplate capacity per second.

Some system operators, such as ERCOT [12], Nord Pool [21], HELCO [19], and EirGrid [8] are considering enacting or have enacted limitations on the ramp rate of wind power. In addition to the small curtailment to produce a reserve discussed above, EirGrid requires wind generators to control their ramp rates within 1- and 10-min limits whenever reasonable, but allows that "…falling wind speed or Frequency Response may cause either of the maximum ramp rate settings to be exceeded" [8]. ERCOT, the system operator in most of Texas, limits wind plants to a ramp rate of 10 % of nameplate capacity per minute when responding to or released from a deployment order[2] [12]. ERCOT also requires wind generators to install and utilize automatic control systems that adjust power output to provide frequency regulation. Since there is no requirement for a reserve-producing curtailment, frequency response is limited to down ramping or periods when wind is curtailed for other reasons (such as curtailment under economic dispatch).

Prior research examining the effects of exposing wind generation to market prices has been focused on whether feed-in tariffs should be replaced by a system more like those used in the US, where wind is affected by market prices[3] [14, 16]. Ela [9] shows the value of wind curtailment in a simple transmission network, and Wu and Kapuscinski find that the value of wind curtailment can be significant from a system perspective [27]. Most additional wind integration research has been focused on system efforts to integrate increasing amounts of wind variability, and generally neither compares different variability-mitigating market rules nor examines the effect that these market rules might have on wind generators. This approach implicitly assumes that wind generation can do little or nothing to manage its own variability.

In this research, we examine several different variability-mitigating market rules for wind generation, and investigate the effect that each rule has on the operation and profitability of wind plants. We examine several possible responses from wind generators, such as economic curtailment (under economic curtailment, the wind plant stops producing energy during periods when that energy is unprofitable), curtailment to produce an operating reserve, or installing energy storage. For each potential market regulation, we determine the favored wind generator operational strategy, the change in revenue to individual wind plants, and the effect that the regulation has on the variability from the set of all wind plants.

2 Data and methods

We use time-series modeling of wind plants in ERCOT to determine the effect that different wind variability market policies have on the operational strategies, revenue, and variability of wind plants. We examine several scenarios, each with a different set of wind variability-related market rules.

Each wind plant attempts to maximize revenue, given a potential power output from the wind plant, energy and frequency regulation prices, and the wind integration rules for the given scenario. Time-series modeling of wind generation is used throughout this

research with a time step of 15 min. The wind data set consists of observed 15-min energy production from 16 wind plants in West Texas for the years 2008 and 2009 [11]. The data are from wind plants with installed capacity ranging from 25 to 500 MW and capacity factors during those years from 18 to 41 % (median = 32 %, mean = 31 %).

Market clearing prices for balancing energy service (BES) and frequency regulation in West Texas for 2008–2009 are used (Fig. 1). The BES price clears in 15-min increments, and had a mean of $39.5/MWh in 2008–2009. The BES price had a maximum of $2,320/MWh in this period, a minimum of −$1,981/MWh, and was between −$32/MWh and $105/MWh 90 % of the time. The frequency regulation market in ERCOT was cleared hourly during this period, and separated into "regulation up" and "regulation down" prices. The prices for both regulation services varied between approximately $1 and $500 per MW-h in 2008–2009. The average regulation up price was $16/MW-h and the average regulation down price was $13/MW-h. Regulation up had a higher price during most hours of the day, especially during the daily peak, but regulation down prices were usually higher overnight due to generators' preference to stay on-line and prevent start-up costs. Wind forecast data, used for the forecast-matching scenario, are from AWS Truepower and forecast 6 h ahead in 1 h intervals [28].

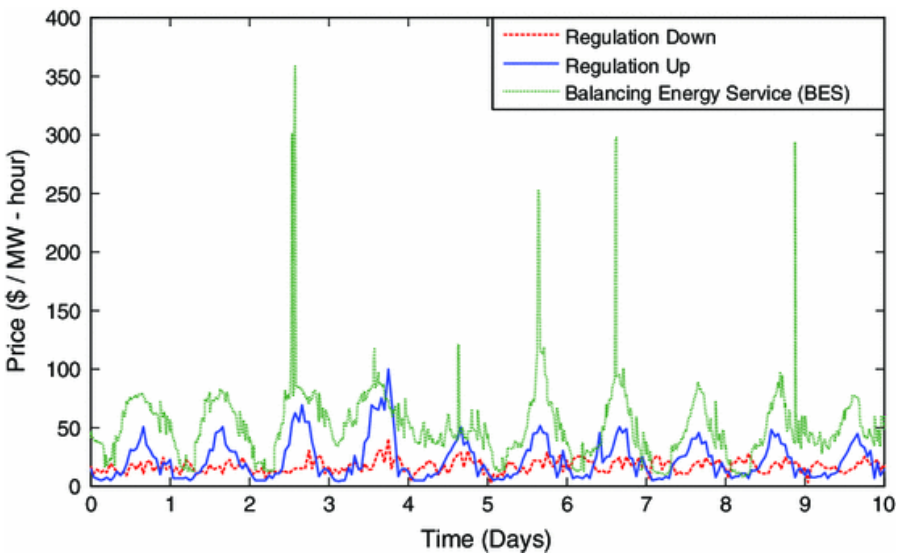

Fig. 1

Energy and frequency regulation prices in ERCOT's West Texas Zone for 10 days in September 2008, shown as an example of the variability in prices

Under each market rules scenario, wind plants are modeled as price-takers selling their energy into the real-time market. Wind generators attempt to maximize overall profit by choosing a power output at each time step that maximizes net revenue during that time step. Net revenue is defined as income (energy payments, production tax credit, and renewable energy credits) minus variability-related penalties. Other costs (maintenance, rent) are assumed to be equivalent across policy scenarios and are not included. The wind generators operate without perfect information, and do not have access to future prices or wind output information. After the power output of the wind generators are

determined, the wind revenue and variability characteristics are calculated and compared across scenarios. Figure 2 shows a block diagram of the modeling approach.

Fig. 2

Block diagram describing modeling used in this research

In this model, wind generators offer electricity on the real-time market. Many actual wind generators sell their energy at fixed prices through long-term power purchase agreements. There are two justifications for our modeling approach. First, the results and discussion are centered on the difference in revenue between the base scenario and an alternative scenario of interest, which represents the cost of compliance with the policy and would still be incurred by wind generators under long-term contracts. Second, under a long-term supply agreement, purchasers could request that wind curtail, pay the wind plant for energy that would have been produced (including payment for the lost subsidies), and purchase replacement energy from the balancing energy market whenever doing so would be more profitable. This would result in curtailments that are the same as those of a wind generator selling energy on the spot market, though the fiscal transfers would be different. Existing contracts may not include provisions allowing for this strategy, though it should be expected in the future because it permits renewable energy buyers to save money without any penalty to wind energy producers.

Six market regulation scenarios are examined (Table 1). First, the base case where wind is free to sell energy on the balancing energy market without penalty or constraint. Second, application of a fixed (per MWh) wind integration fee to wind generators. Third, a BPA-style wind balancing tariff applied to wind generation (per MW of installed capacity per month). Fourth, a limit on the up-ramping of wind power, in units of percent of nameplate capacity per time step, where wind is penalized for over-ramping. Fifth, a limitation on both up- and down-ramping of wind power (in percent of nameplate capacity per time step), and wind is penalized for over-ramping. Sixth, a requirement that wind power output must match a forecast (within a certain percent of nameplate capacity) or pay a penalty.

Table 1

Summary of the six market regulation scenarios examined in this research

Scenario	Description
Base case	Wind generators sell energy on the balancing energy market without restriction or penalty
Wind integration fee (per MWh)	Wind generators pay a fixed fee (per MWh) on all wind energy produced to cover the cost of wind-related ancillary services
Wind balancing tariff (per MW-month)	Wind generators pay a fixed tariff (per MW-month) to cover the cost of wind-related ancillary services
Limited up-ramping	Wind generators have a limited up-ramp rate (a percentage of nameplate capacity per time step) and must pay a penalty based on the current frequency regulation price if ramping is above the defined limit
Limited up- and down-ramping	Wind generators have limited up- and down-ramp rates (a percentage of nameplate capacity per time step) and must pay a penalty based on the current frequency regulation price if ramping is above the defined rate in either direction
Penalty for diverging from wind forecast	Wind generators must match their power output to the 6-h-ahead wind power forecast for the area, within an allowed deadband. The generator pays a penalty, based on current frequency regulation price, for power output outside of the deadband

We considered three responses from wind generators: economic curtailment, curtailment to produce an operating reserve, and use of energy storage. Both curtailment to produce a reserve and the use of energy storage were found to be less profitable for wind generators than economic curtailment in all of the examined scenarios. Thus, we focus here on wind generators using economic curtailment, and discuss curtailment to produce a reserve and use of energy storage in Appendix A.

In this model, a wind generator under economic curtailment will reduce power output whenever the energy price plus Renewable Production Tax Credit ($21/MWh for 2008–2009) and Texas Renewable Energy Credit price (between $1.5 and $5 per MWh, varied by month) minus any penalties is below zero. Without any limitations on ramping or a requirement to meet forecast, a wind generator will choose to produce either the

maximum possible energy or no energy at all, depending on whether the current energy price is below or above the breakeven price for wind energy (Fig. 3).

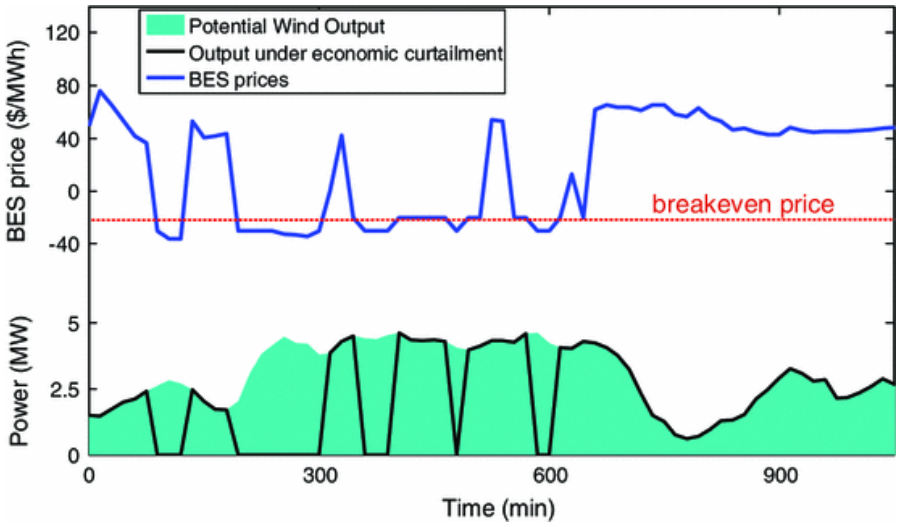

Fig. 3

Example output of a revenue-maximizing wind plant under economic curtailment (*black line*, *lower plot*), plotted over the potential power output (*light blue area*, *lower plot*). The *upper plot* shows BES prices (*blue line*, *upper plot*) over a 17 h period with frequent negative prices. In this example, there are no constraints on the power output of the wind plant. The *dashed red line* indicates the breakeven price for wind energy, which is approximately −$24/MWh in this period (it is below zero because of the combination of payments from the PTC and REC sales). Under economic curtailment, the wind plant stops producing energy during periods when that energy is unprofitable. While this strategy can increase the revenue to a wind plant and relieve over-production of energy, it also produces increased short-term wind fluctuations as the wind plant ramps up and down to maximize revenue

In addition to being the profit-maximizing strategy, there is empirical evidence that wind plants are using economic curtailment as described above. The observed (not modeled) BES clearing prices in West Texas show an intermittent “price floor” around the breakeven wind energy price, suggesting that economic curtailment is a common strategy used by wind generators bidding into the BES market, and is occasionally setting the clearing price for electricity (Fig. 4). While the BES data does not reveal how many wind generators are operating under an economic curtailment strategy, we believe that it is a prudent choice and assume that wind generators will follow this strategy unless prevented by system regulations.

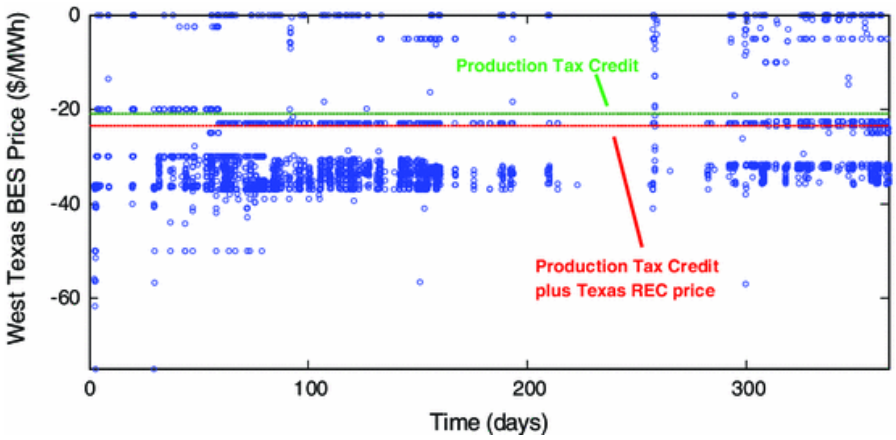

Fig. 4

Negative BES prices in West Texas in 2008. Each *circle* represents one 15-min period with a negative BES price. The Production Tax Credit (−$21/MWh) and PTC plus Texas Renewable Energy Credit prices (approximately −$24/MWh in this period) have been added. The BES price often falls just above these price points, suggesting that wind generators are bidding those values into the BES market and curtailing their output whenever the effective price of wind energy goes below zero, resulting in an occasional "price floor" at those values

Wind plant decision-making is based on the BES price. When a wind generator is constrained by additional limitations (such as penalties for exceeding a ramp rate), wind generators will sometimes choose an intermediate power output as the revenue-maximizing output. In the scenarios with penalties for over-ramping or diverging from forecast, the penalties are based on the frequency regulation prices (discussed in greater detail in Appendix B).

Under economic curtailment, the wind generator chooses a power output between zero and the potential power output at each time step t, attempting to maximize revenue at each step (Eq. 1). E(t) is the energy produced by the wind plant in period t, $P_{BES}(t)$ is the BES price during period t, P_{PTC} is the value of the Production Tax Credit ($21/MWh in 2008/2009), P_{REC} is the Renewable Energy Credit price, and D(t) is the penalty payment.

$$\max(E(t)) \cdot (P_{BES}(t) + P_{PTC} + P_{REC}(t)) - D(t))$$

(1)

For the scenario where a wind integration fee (per MWh) is applied, payments are calculated using Eq. 2, where W_f is the wind integration fee ($/MWh).

$$D(t) = E(t) \cdot (W_f)$$

(2)

When a fixed wind integration tariff (per MW-month) is applied, payments are calculated with Eq. 3, where C is the capacity of the wind plant (MW) and W_T is the wind integration tariff ($/MW-month). 2,920 is the number of 15-min periods in an average month. The wind integration tariff is constant and unrelated to the wind energy production at time t (as in the Bonneville Power Authority area).

$$D(t) = C \cdot W_T/2{,}920$$

(3)

When the up-ramp rate of a wind plant is limited, the penalty payments are calculated using Eqs. 4 and 5, where $A_{ramp\ rate}$ is the allowed ramp rate (percent of capacity per time step) and $P_{reg\ down}(t)$ is the regulation down price during period t ($/MW-h), and M is the penalty multiplier.

$$D(t) = 0 \quad (if\ E(t) \leq E(t-1) + C \cdot A_{ramp\ rate})$$
(4)

$$D(t) = [E(t) - (E(t-1) + C \cdot A_{ramp\ rate})] \cdot P_{reg\ down}(t) \cdot M \quad (if\ E(t) > E(t-1) + C \cdot A_{ramp\ rate})$$
(5)

For the scenario where the ramp rate is limited for both up- and down-ramping, Eqs. 6, 7, 8 are used to determine penalty payments.

$$D(t) = 0 \quad (if\ E(t-1) - C \cdot A_{ramp\ rate} \leq E(t) \leq E(t-1) + C \cdot A_{ramp\ rate})$$
(6)

$$D(t) = [(E(t-1) - C \cdot A_{ramp\ rate}) - E(t)] \cdot P_{reg\ up}(t) \cdot M \quad (if\ E(t) < E(t-1) - C \cdot A_{ramp\ rate})$$
(7)

$$D(t) = [E(t) - (E(t-1) + C \cdot A_{ramp\ rate})] \cdot P_{reg\ down}(t) \cdot M \quad (if\ E(t) > E(t-1) + C \cdot A_{ramp\ rate})$$
(8)

In the scenario where wind is penalized for diverging from forecast, the penalty payments are determined using Eqs. 9, 10, 11, where F(t) is the scaled wind energy forecast at time t (MW) and $A_{deadband}$ is the allowed deadband (percent of capacity).

$$D(t) = 0 \quad (if\ F(t) \cdot (1 - A_{deadband}) \leq E(t) \leq F(t) \cdot (1 + A_{deadband}))$$
(9)

$$D(t) = [(F(t) \cdot (1 - A_{deaaband})) - E(t)] \cdot P_{reg\ up}(t) \cdot M \quad (if\ E(t) < F(t) \cdot (1 - A_{deadband}))$$
(10)

$$D(t) = [E(t) - (F(t) \cdot (1 + A_{deadband}))] \cdot P_{reg\ down}(t) \cdot M \quad (if\ E(t) > F(t) \cdot (1 + A_{deadband}))$$
(11)

All wind generators are assumed to be price-takers and the balancing energy prices are not modified for the different scenarios. As discussed in Appendix A, wind generators are allowed to purchase energy storage or intentionally curtail their output to produce an operating reserve, but it is assumed that they do not otherwise self-supply any ancillary services (from a co-located or nearby thermal generator, for example).

Power spectral density (PSD) calculations are applied to the time-series power output data to investigate the effect that market policies have on the variability of wind at different frequencies [1]. Most of the investigated scenarios result in reductions in short-term (high frequency) fluctuations of wind generation, and PSD analysis allows quantitative comparison of those reductions. Because the system operator is most interested in the overall variability of all wind plants rather than the variability of individual generators, all PSD calculations use the total power output from the 16 wind plants. The spectra are noisy even after 8-segment averaging has been applied (see Fig. 5), so the average of the nearest 29 data points to the exact frequency (approximately ±2 % of the target period) is used to calculate the variability at 30, 120, and 480 min. Changes in market policy regarding wind generation were generally found to have the largest effect on short-term variability, which is also the variability that is most costly to

mitigate with other resources. Thus, most of the discussion below is focused on 30-min variability, the shortest period available from PSD analysis.

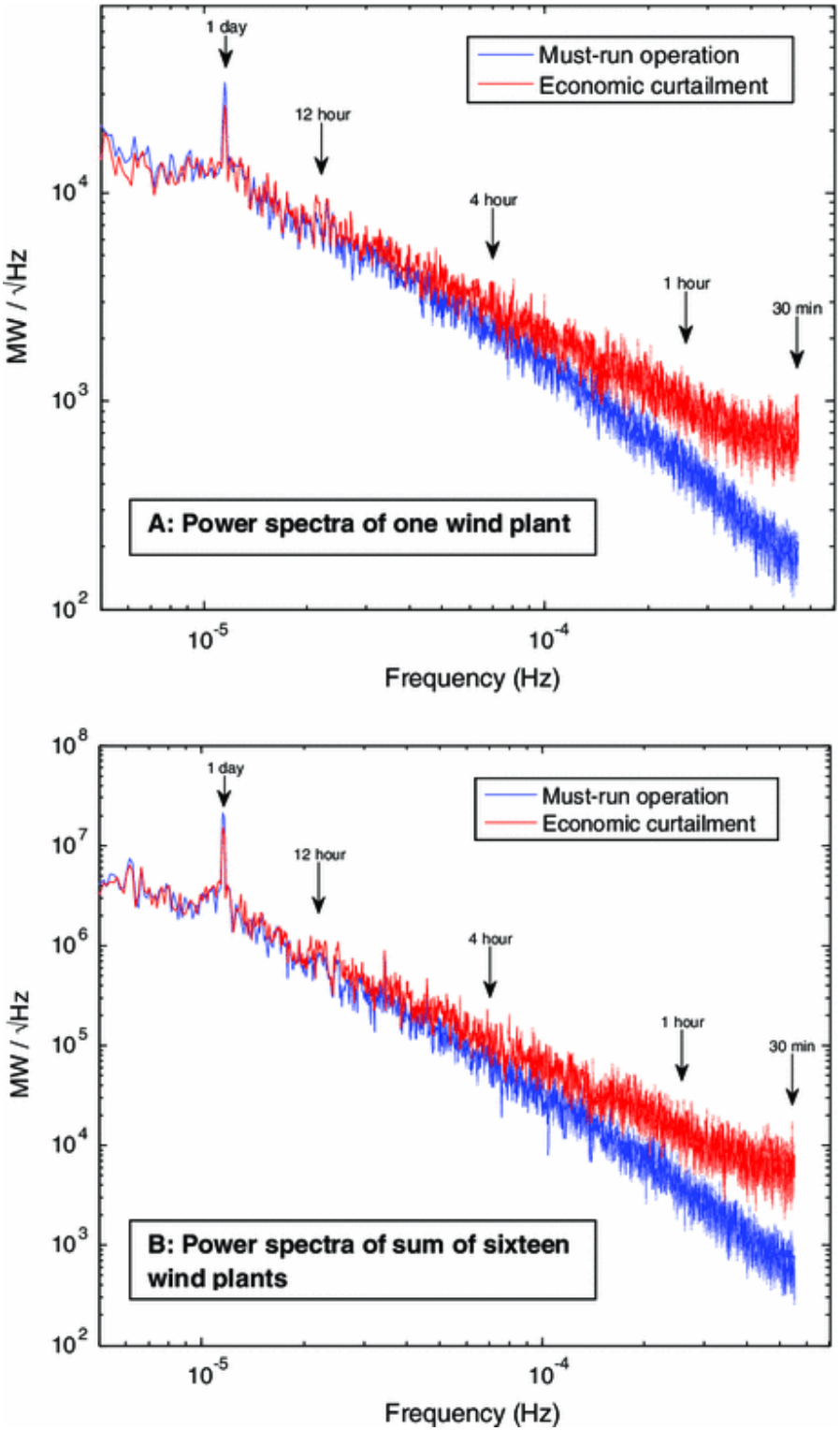

Fig. 5

Power spectra of **a** wind power from one of the examined wind plants and **b** total wind power from 16 wind plants, under must-run (*lower curve*, *blue*) and economic curtailment (*upper curve*, *red*) strategies. Increased

variability under economic curtailment causes the power in higher frequencies to increase substantially: 350 % at 30 min, 200 % at 1 h, and 35 % at 4 h, thus increasing the amount of smoothing required from other generators. The collective power output of 16 wind plants maintains the same trend as individual wind plants, with a small amount of intra-plant smoothing. Eight-segment averaging has been applied to construct each spectrum

3 Results

We consider the response of wind generators to changes in electricity market rules relating to wind output. For each of the six market scenarios described in Table 1, we determine the profit-maximizing operation of each wind plant, calculate the expected changes in revenue to each wind plant, and determine the 30-min variability from the collected set of 16 wind plants.

3.1 Economic curtailment (base case)

In areas that have significant wind penetration, such as West Texas, market-clearing prices for energy can become negative in periods of high wind and low load. In the 2008–2009 period, economic curtailment increases the revenue of the studied wind plants by 2.5 %, or $3,500/MW-year, over the revenue gained when wind plants are operated under a “must-run” strategy. The result under economic curtailment is used as the base case for comparison with the other scenarios, as it reflects the status quo in many electricity markets.

Though economic curtailment consistently increases the revenue to wind generators, it also increases the short-term variability in the wind energy output (Fig. 3). This additional variability causes a noticeable increase in the amplitude of short-term fluctuations from both individual wind plants and the total output from a collection of 16 wind plants (Fig. 5). Both the value of economic curtailment and the increased variability that it produces are a direct result of the negative prices in West Texas in the examined period.

3.2 Wind balancing tariff

A wind balancing tariff, which charges wind generators a fixed fee per installed capacity, should have no effect on the operation of existing wind generation but is included because this is a strategy currently used in BPA. The wind balancing tariff takes a fixed ($/MW-month) fee from wind generators regardless of their output or operation, and a profit-maximizing generator will use the same operational strategy that they would without the tariff. Under a tariff of $680/MW-month, the rate set by BPA for 2008, average wind plant revenue drops from an average of $150,000/MW-year (range $97,000–$204,000/MW-year) to $142,000/MW-year (range $88,000–$196,000/MW-

year), a decrease of 5.6 % (4.0–8.5 %). Changes in the tariff have a linear effect on wind generator revenue, and a tariff at the 2010 rate of $1,090/MW-month will reduce revenue by an average of 9 %.

3.3 Wind integration fee

A wind integration fee (in $/MWh produced) would act as a decrease in the PTC/REC subsidy, and would shift the price point below which wind is willing to curtail. A $5/MWh fee reduces wind generator revenue by an average of 7.7 % and a $10/MWh fee decreases revenue by an average of 15.2 %.

Implementation of a wind integration fee ($/MWh) will cause wind generators to curtail more energy because it will raise the energy price at which producing wind energy is profitable. A wind integration fee does not motivate wind generators to reduce variability. The total output of the 16 wind plants showed an increase in variability in the 120 and 480 min time periods, while the 30-min variability initially increased and then decreased at higher fee rates (Fig. 6). These trends were not robust and there was significant variation across the individual wind plants. Though making general conclusions from these data is difficult, the results suggest that a $/MWh wind integration fee is not an effective way of decreasing variability, and may cause it to increase. However, the proceeds from such a fee can be used to purchase variability-compensating generation.

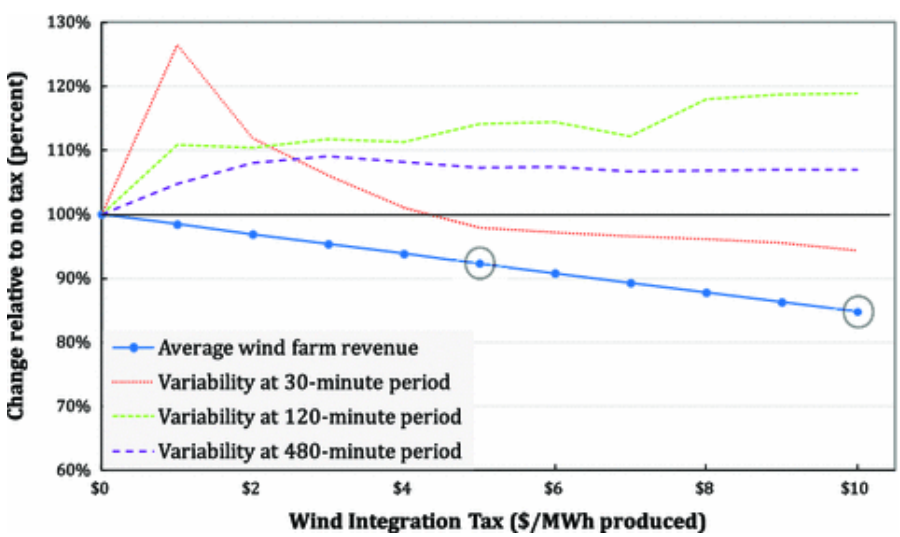

Fig. 6

Average wind generator revenue and 30-, 120-, and 480-min variability of wind power (sum of 16 wind plants) at different wind integration fee rates. The revenue to wind generators decreases approximately linearly with wind integration fee, and is very consistent between wind plants. While the total amount of 120- and 480-min variability increased and the 30-min variability eventually decreased with increasing wind integration fees, there was significant variation between wind plants. The *two circled points* are those used for the comparison figures (Figs. 11, 12)

3.4 Limited up-ramping of wind

Limiting only the up-ramping of wind energy is a feasible method of decreasing wind variability because modern wind generators normally have the ability to control their positive ramp rate through curtailment. Two parameters are examined within a market scenario that limits the up-ramping of wind: the ramp rate limit, and the penalty for violation of the ramp limit. The ramp rate is defined as the percent of nameplate capacity that a wind plant is allowed to increase its power output per 15-min time step. In this scenario, there is no limit on the rate at which wind plants decrease their power output (down-ramp).

The up-ramp rate limit is varied between 2 and 40 % (per 15-min time step) of a wind plant's nameplate capacity. The penalty for over-ramping is varied between 0.25 and 5 times the down-regulation price. Figure 7 shows the effect of different ramp rate limits and penalty amounts on the revenue to and variability of wind plants. Increasing the penalty reduces both the variability of wind output and the revenue to wind generators, while a decrease in the allowed ramp rate from 40 % affects mainly the revenue to wind generators. Within the studied ranges for ramp rate and penalty, doubling the penalty decreases 30-min fluctuations by an average of 4.5 % and almost doubles (1.8×) the amount of revenue lost by the wind generators. Doubling the ramp rate limit increases fluctuations by a negligible amount (0.6 %), but reduces the revenue losses to wind generators by 40 %. If the goal of a ramp rate limitation is to decrease variability while having as little effect as possible on wind generation, this can best be achieved by using a less binding (20–40 %) ramp rate limit. This effect is discussed in Appendix C.

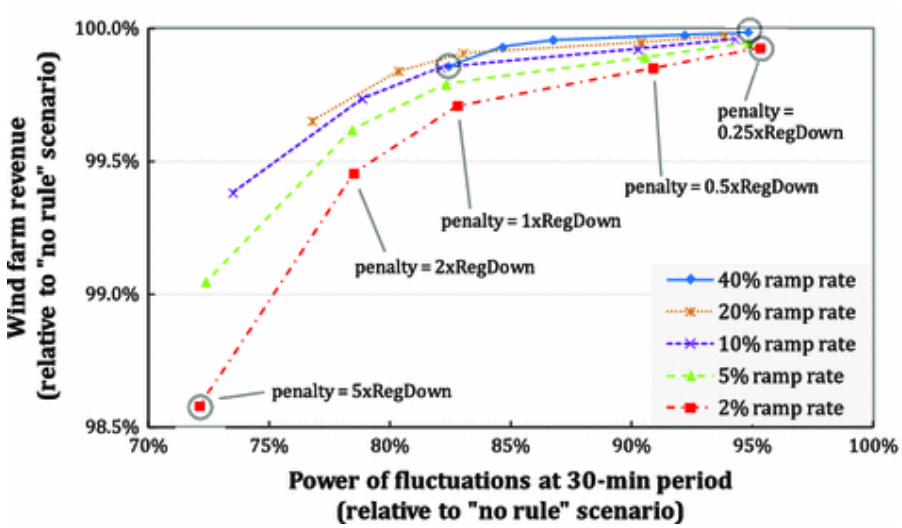

Fig. 7

Average change in revenue (average of 16 wind plants) and change in 30-min variability (from the total output of 16 wind plants) under a market scenario with a limitation on up-ramping of wind generators. Higher penalties for violation of the ramp limit result in decreased variability from a wind plant, while decreasing the ramp rate limit tends to affect only the wind generator revenue. If the goal of a ramp rate limitation is to decrease

the variability of wind, this can be accomplished with the least effect on wind generators by establishing a high ramp rate (20–40 %) limit along with a high penalty payment. Ramp rate is in percent change per 15-min time step. The *four circled points* are those used for the comparison figures (Figs. 11, 12)

3.5 Limiting the up- and down-ramping of wind

Applying a limit on the up-ramping of wind output addresses only half of the potential changes in power from a wind plant and provides no motivation for wind generation to ramp down gradually. As with the up-ramp limit above, two parameters are examined for market rules limiting both the up- and down-ramping of wind: the ramp rate limitation, and the penalty for violation of the ramp limit. The ramp rate limit is varied between 2 and 40 % (per 15-min time step) of a wind plant's nameplate capacity. The penalty for over-ramping is varied between 0.25 and 5 times the appropriate frequency regulation price (up regulation price is used when wind ramps down too quickly and down regulation price for wind ramping up too quickly). The results (Fig. 8) are qualitatively similar to the scenario where only up-ramping of wind is limited, but larger in scale. When limits are applied to both up- and down-ramping, the decrease in revenue is approximately double that observed for up-ramping only. As with the up-ramp limit scenario, the most effective way to use a ramp rate limit to reduce system wind variability while minimizing the costs faced by wind generation is to apply a relatively loose ramp rate (40 %) and a high penalty.

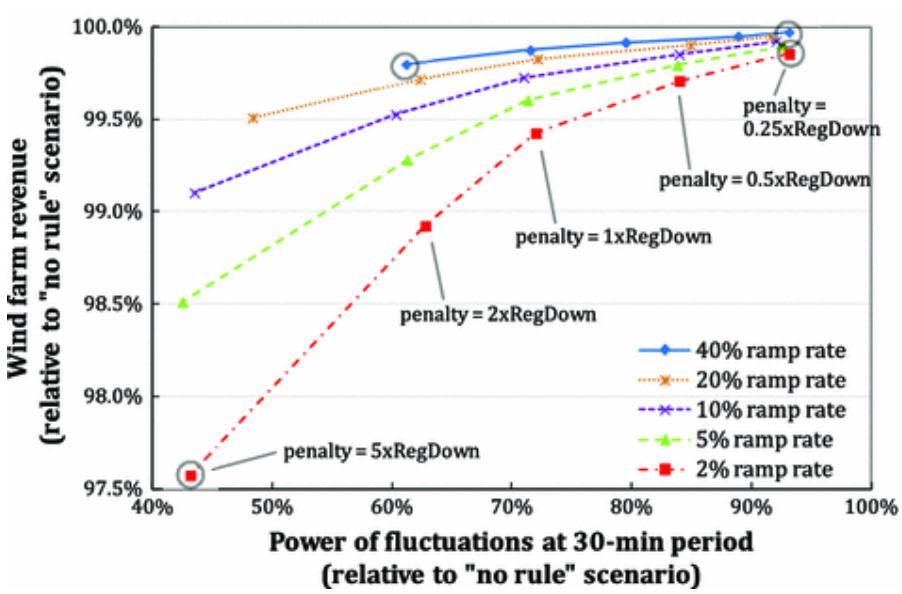

Fig. 8

Average change in revenue (average of 16 wind plants) and change in 30-min variability (from the total output of 16 wind plants) under a market scenario with a limitation on up- and down-ramping of wind generators. Higher penalties for violation of the ramp limit result in decreased variability from a wind plant, while decreasing the ramp rate limit tends to affect only the revenue. If the goal of a ramp rate limitation is to decrease

the variability of wind, this can be accomplished with the least effect on wind generators by establishing a high ramp rate (40 %) limit along with a high penalty payment. Ramp rate is in percent per 15-min time step. The *four circled points* are those used for the comparison figures (Figs. 11, 12)

The averaged trends shown in Figs. 7 and 8 are consistently followed by individual wind generators. Figure 9 shows the change in revenue and 30-min variability for individual wind plants under an up- and down-ramp limit of 40 % per 15-min time step. The average line is similar to the top line in Fig. 8, except that the 30-min fluctuations are evaluated for each wind plant individually rather than collectively. The reduction in 30-min variability is relatively consistent across the set of wind plants, with most points within 10 % of the average value. The distribution of revenue reduction is small at low penalty levels and larger at high penalty levels. This is due to some wind plants having an output that is naturally more variable and less amenable to ramping constraints. As the penalty for over-ramping is increased, this difference amplifies the relative change in revenue of the wind generators, as wind plants that are less able to control their ramping are more affected by the ramping limitations.

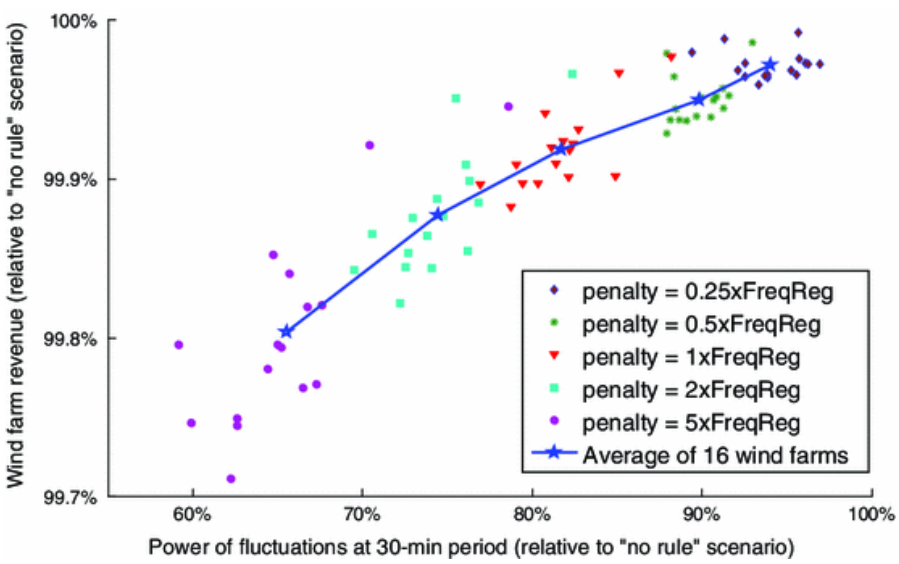

Fig. 9

Change in revenue and 30-min variability of 16 wind plants under a market scenario with a limitation on both up- and down-ramping (ramp limit of 40 % per 15-min time step). The *solid blue line* and *stars* show the average results at each penalty level while the *colored shapes* show the results for individual wind plants

3.6 Penalty for diverging from wind forecast

Instead of attempting to reduce the variability of wind power, a system operator could incentivize improvements in the predictability of wind by penalizing wind plants that diverge significantly from wind forecast. This structure has some similarities to the

Midwest ISO Dispatchable Intermittent Resources Program and California ISO's Participating Intermittent Resources Program, where the operation of participating wind resources is constrained by wind power forecasts [7, 20].

In the forecast-matching scenario, the power output of wind plants (as a percent of nameplate capacity) must be within an allowed deadband of the forecast wind output (as a percent of total system wind capacity). We model a scenario in which the 16 wind generators are required to match the 6-h-ahead ERCOT system wind forecast, which is essentially a West Texas wind forecast. Two parameters are examined: the size of the deadband is varied from 5 to 60 % of nameplate capacity, and the penalty for output outside the allowed deadband is varied between 0.25 and 5 times the appropriate frequency regulation price.

Figure 10 shows the average effect that the two parameters have on wind generator revenue and adherence to forecast, demonstrating that large deadband allowances (40–60 %) can provide the same reduction in root-mean-square error (RMSE) as tighter deadband levels, but at lower cost to wind generators. In the base case "no rules" scenario, the average RMSE of the 16 wind plants is 26.1 % of nameplate capacity. Requiring that wind plants match forecast within a 40 % deadband (with a penalty of five times the frequency regulation price) reduces the RMSE to 25.4 %, a very small change, and results in a 3 % reduction in the revenue to wind generators. Wind integration rules of this type prompt very little response from wind generators and are not substantially different than the wind balancing tariff described above.

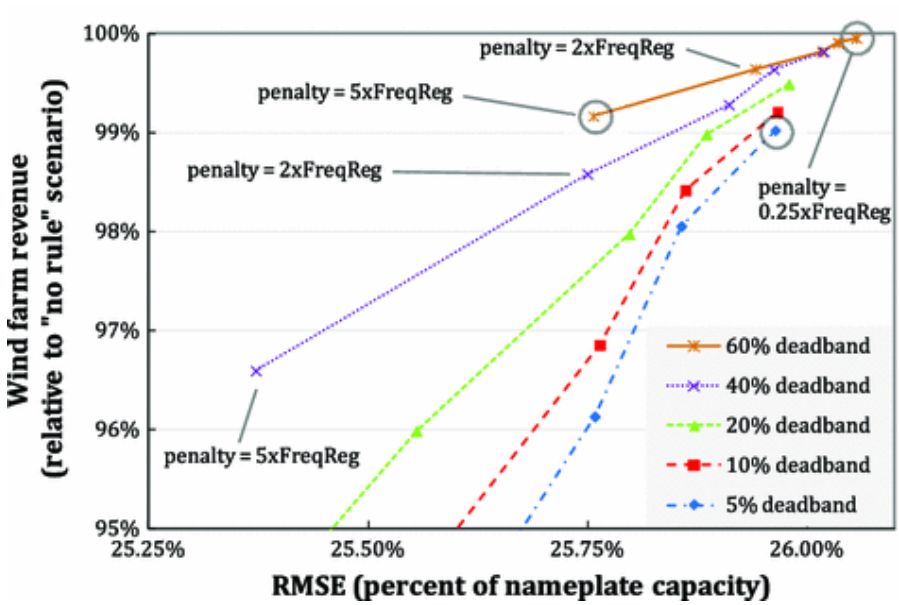

Fig. 10

Average change in revenue and RMSE under a market scenario where wind generators are penalized for diverging from the 6-h forecast. Each point is the average of 16 wind plants. The *three circled points* are those used for the comparison figures (Figs. 11, 12)

Under a market scenario where wind plants are required to meet a forecast, wind generators may prefer to report a lower production capacity than their true nameplate capacity. This is essentially a strategic "underforecasting" by the wind plant in order to maximize revenue. As the amount of underforecasting increases, wind generators have a greater ability to meet forecast through curtailment when the penalty is greater than the value of energy produced. We model this by proportionally reducing the forecast faced by a wind plant by a fixed amount. For each scenario where wind generation is penalized for diverging from forecast, the amount of underforecasting that results in maximum revenue is determined for each wind plant. In some cases, when the penalty is low and the deadband is high, some wind plants choose to have little or no underforecasting. As the penalties and deadband amounts get more restrictive, the amount of underforecasting increases, as shown in Table 2. In the most restrictive scenarios, the amount of underforecasting is around 50 % on average, but can be almost 80 % for individual wind plants. Strategic underforecasting results are discussed further in Appendix C.

Table 2

Average amount of underforecasting chosen by wind plants as a function of deadband allowance and penalty for diverging from forecast

Average amount of underforecasting chosen by wind generators	**Penalty (percent of frequency regulation price)**				
	25 %	**50 %**	**100 %**	**200 %**	**500 %**
5 % deadband	45.9	46.3	46.7	47.0	47.6
10 % deadband	36.1	36.5	36.9	37.2	37.7
20 % deadband	22.6	22.9	23.1	23.4	23.7
40 % deadband	10.6	10.6	11.1	11.1	11.1
60 % deadband	6.6	6.6	6.6	6.6	6.6

In scenarios with more stringent forecast-matching requirements, wind generators choose more underforecasting because it is much cheaper to curtail down to a forecast power output than to pay the penalty for under-producing. While increasing the penalty has a small effect on the amount of underforecasting, it greatly reduce the revenue to wind plants (see Fig. 10)

3.7 Summary of results

The effect that different market rules have on the change in 30-min fluctuations and revenue to wind generators is summarized in Fig. 11. Not all of the examined market rules directly attempt to reduce wind variability, so this figure does not express the full value of each market scenario. For example: while penalizing wind generators for diverging from forecast does reduce variability, the primary goal of that policy is to improve the predictability of wind power.

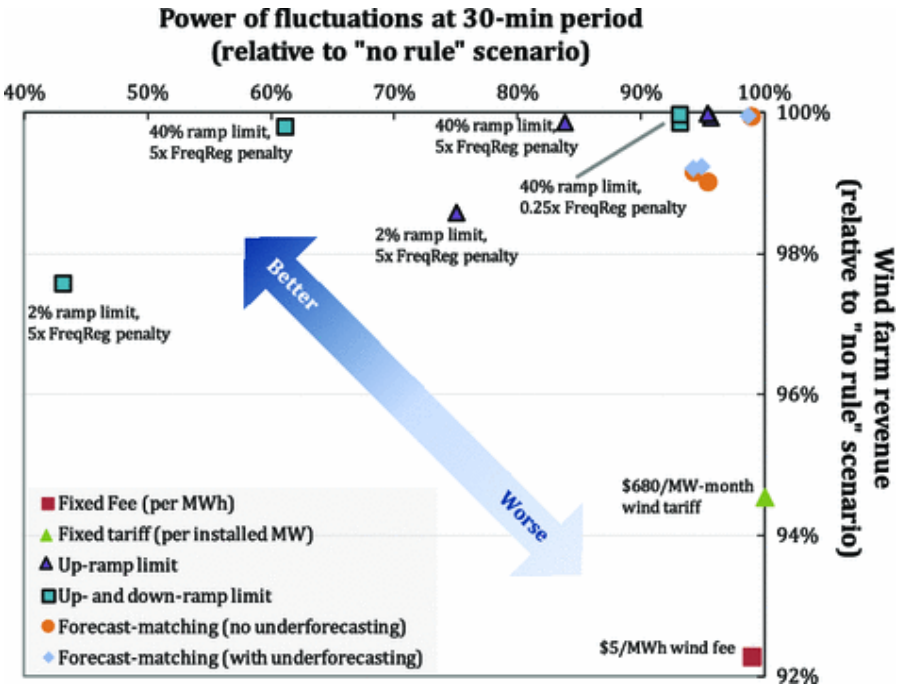

Fig. 11

Average change in revenue and 30-min variability of wind generators under selected market scenarios. For ease of interpretation, only a few points from each market scenario are displayed. Some market rules, such as a limitation on the ramping of wind, can reduce the 30-min variability of wind without greatly reducing the revenue to wind generation. The "forecast-matching" scenarios do reduce variability, but their primary goal is improving adherence to forecast, which is not expressed on this figure. Revenue is the average of 16 wind plants, power of fluctuations is for the sum of all wind plants, and all scenarios permit economic curtailment of wind generation

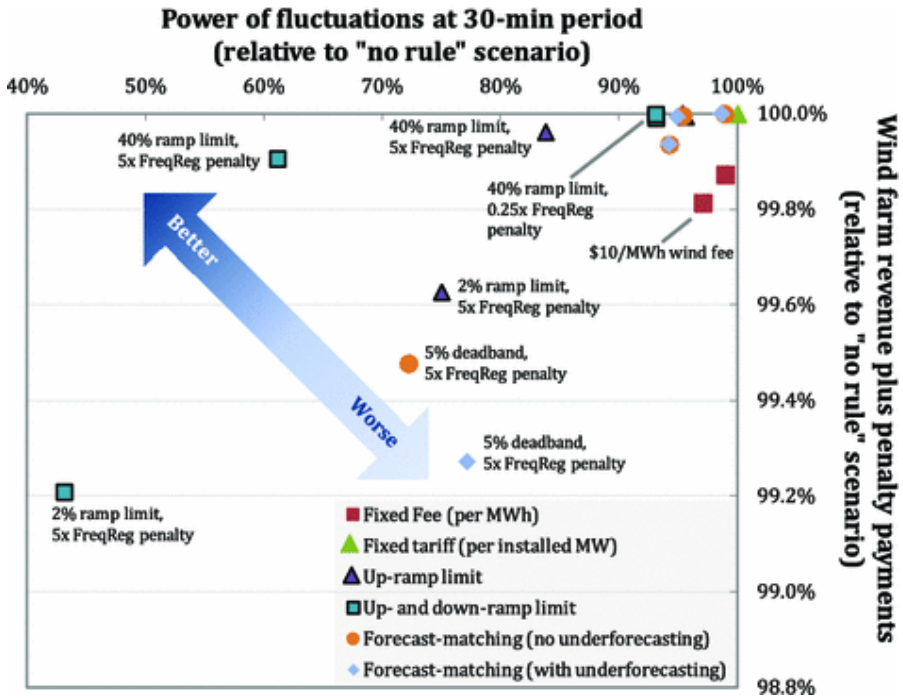

Fig. 12

Average change in revenue + penalty payments and 30-min variability of wind plants under selected market scenarios. Change in wind revenue plus penalty payments shows the average effect when all penalty payments are redistributed to wind generators (a “feebate” program). For ease of interpretation, only a few points from each market scenario are displayed. The “forecast-matching” scenarios do reduce variability, but their primary goal is improving adherence to forecast, which is not expressed on this figure. Revenue is the average of 16 wind plants, power of fluctuations is for the sum of all wind plants, and all scenarios permit economic curtailment of wind generation

Wind generators will naturally resist a set of market rules that introduces new costs to the operation of wind. If the penalty payments or new wind subsidies are redistributed to wind generators, the costs of wind variability can be partially internalized to generators while having little or no effect on average revenue. Figure 12 shows the change in the power of 30-min fluctuations versus “wind revenue plus penalty payments”, under various market scenarios. Including the penalty payments is a way of examining the total system costs. Figure 12 assumes that the penalty payments are returned to wind generators in a “feebate” system where penalty payments are redistributed to wind generators on a capacity basis. Such a system would still motivate reductions in variability while taking significantly less revenue from wind farms. However, the revenues for noncompliance are then not available to purchase variability-mitigating services.

Figures 11 and 12 show that, of the market scenarios examined, limiting the ramp rate of wind generators may be the best way to reduce the short-term (30-min) variability of wind generation at lowest cost. The scenarios that require wind generation to match forecast have the favorable property that they can result in reductions in the 30-min

variability of wind, even though this is not a primary goal of the market rule (see Fig. 11). While the forecast-matching limitations may result in a significant reduction in wind revenue (up to 15 % for the scenarios investigated), most of the revenue loss is due to penalty payments which could be redistributed to the wind generators. A summary of the effects of different market policies for wind variability is provided in Table 3.

4 Discussion

In West Texas over the 2008–2009 period, economic curtailment increased the revenue of the studied wind plants by an average of 2.5 %. At the same time, economic curtailment increases the overall variability of wind generation, due to the rapid changes in power output when the wind generation begins or ends a curtailment. Adding market rules that limit the ramp rate of wind can decrease variability, but none of the examined market scenarios reduces the system wind variability back to the level observed if wind is operated as a must-run resource.

Table 3

Effects of different market policies for wind integration on the revenue and variability of wind plants (relative to the “no rules” scenario)

Scenario	Decrease in 30-min variability (%)	Parameters	Decrease in wind plant revenue (%)	Decrease in wind plant revenue under a "feebate" system (%)
Limited up- and down-ramping	40	40 % ramp limit, 5 ×FreqReg penalty	0.25	0.10
Penalty for diverging from wind forecast (underforecasting permitted)	23 (8 % improvement in RMSE)	5 % deadband, 5 ×FreqReg penalty	14	0.70
Limited up-ramping	16	40 % ramp limit, 5 ×FreqReg penalty	0.15	0.05
Penalty for diverging from wind forecast	6 (0.8 % improvement in RMSE)	60 % deadband, 5 ×FreqReg penalty	0.90	0.10
Wind integration fee (per MWh)	3	$10/MWh fee	15	0.20
Wind balancing tariff (per MW–month)	0	$680/MW-month tariff	5.50	0

While variability is generally problematic, some of the fluctuation under economic curtailment may be beneficial from a system perspective. With any intervention into the operation of wind generation, such as economic curtailment or a ramp limitation, the fluctuations are no longer the direct result of random weather patterns, since they are also reflect the prices of energy and other services in the electricity market. Under economic curtailment, wind generators tend to stop energy production when the electricity price is below approximately −$25/MWh (under the existing PTC), and to start up again above that price. Thus, output tends to be curtailed when there is too much electricity production and increased when this constraint is relieved, which is desirable from the system perspective. With the addition of over-ramping penalties, wind fluctuations are also affected by the cost of having other generators ramp up or down. If

the penalty payments are correctly designed, wind generators ramp up quickly only when the value of energy is greater than the cost of having other generators ramp down. When the price signals to wind generators better reflect the true system costs and benefits of their operation, the fluctuations from wind plants will be those that are most valuable or least troubling for the electricity grid. As a result, the wind fluctuations under economic curtailment, while larger in absolute value, are more desirable (on average) from a system perspective.

It is quite possible for a system operator to capture the value of the market rules without any penalty to wind generation by providing a small subsidy when new operational limitations are established. For example, in the scenario where up- and down-ramping of wind is limited to 20 % of capacity per 15-min step with a penalty of five times the frequency regulation price, 30-min variability is reduced by 45 %. The average revenue to wind generators is reduced by 0.5 % ($0.32/MWh), though penalty payments make up about half of that loss. If all penalty payments plus a small subsidy of $0.13/MWh are distributed to wind generators, the wind generators just break even (on average), though the 45 % reduction in short-term variability will still be realized. A subsidy higher than $0.13/MWh would mean that wind generators are, on average, better off under the new system, even though that system adds new limits to wind operation. Thus, pursuing the benefits of market-based limitations to wind output does not necessarily harm wind generators.

Due to our assumption that wind plants are price-takers, this work does not capture all of the dynamics that price-driven variability limits would introduce. However, we believe that the results presented above introduce a promising new method for controlling wind variability and provide insights into the system-level effects that these strategies would have. We investigated six strategies, but other market rules may have very different effects on the profitability and operation of wind generators.

The appropriate market policy depends on the needs of the electricity system. In areas with small amounts of wind generation or where further deployment of wind power is desired, having no restriction on wind variability can encourage further deployment and prevent increased regulatory burden. In electricity systems where the variability of wind is becoming costly or problematic, market rules that limit the ramping of wind (with penalty payments for violating the ramp limits) can significantly reduce the short-term variability of wind with only a minor reduction in the revenue to wind generators. Other market protocols could be created to meet the needs of particular systems.

5 Conclusion

As the quantity of wind generation on electricity grids increases, the costs related to wind integration will become significant, resulting in greater pressure to impose some or all of those costs on wind generators. Market rules that use existing price signals to incentivize decreased variability, such as ramp limitations with penalties based on the frequency regulation price, allow wind generators to participate in variability reduction when the market conditions are favorable. These market-based strategies can both reduce wind

variability and gather payments that can be used for increased ancillary services requirements, and can be designed to make both wind generators and system operators better off than under the status quo.

We have identified market rules that can reduce short-term variability from wind plants by 40 % while reducing revenue by only 0.25 %, relative to the case with no limitation on wind output. The most effective rules appear to be those that apply a ramp rate limit and a fairly large penalty. This is an inexpensive way to significantly reduce wind variability, and appears to be more effective than wind tariffs and other existing strategies.

Footnotes

1. 1.

   The precise settings for wind plant response depend on system conditions and wind plant location, and may be different for different wind plants.

2. 2.

   In ERCOT, a deployment order is an instruction from ERCOT to a generator to generate at a certain power output over the next market period, similar to a dispatch order.

3. 3.

   Feed-in tariffs, which are popular in Europe, guarantee a renewable electricity generator a fixed payment per MWh delivered. Under such a system, wind generators are motivated, for example, to generate electricity whenever possible, without regard for the prevailing energy prices. US wind producers receive both a Federal subsidy and proceeds from energy they sell. Under the US Production Tax Credit, wind generators get a fixed subsidy per MWh but are subject to changes in market rates for the energy they produce. While many wind plants sell electricity under fixed-rate long-term contracts, the negotiation and terms of these contracts are still affected by the prevailing energy costs and the needs of the purchaser, similar to other long-term power contracts.

4. 4.

   The percent of revenue lost is about three times the percent of curtailment because the capacity factor of the wind farms is around one third. Thus, a 1 % curtailment eliminates around 3 % of the energy of the wind farm.

Notes

Acknowledgments

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Appendix A: Alternative operational strategies

In every scenario examined above, the wind plants are allowed to purchase energy storage, in the form of a sodium sulfur (NaS) battery. For several reasons, none of the studied scenarios result in wind purchasing energy storage. First, the high capital cost of this device means that only a very value-intensive application will result in profitable operation. Because the focus of this work was to identify market scenarios that would have only minor effects on wind generators, the potential value of storage is small. Second, the use of energy storage was limited to the time-shifting of wind energy, so the extra benefit of charging from outside resources is lost. Third, the value of storage is greater at shorter time-scales [15] and this work used a time step of 15 min. It is possible that the value of storage would increase significantly in markets where the ramping of wind was limited on time-scales shorter than 15 min.

Another strategy that wind generators were allowed to choose was curtailing the wind output slightly to produce an operating reserve that could be used to buffer down-ramping. This strategy only makes sense in the market scenario where wind is penalized for down-ramping, though it was never chosen as a strategy because the value of the lost wind energy was always greater than the value of the operating reserve. The revenue to wind plants is reduced by an average of 3.25 % when the output is curtailed by 1 % of nameplate capacity.[4] Under the strictest ramp limitation (2 % up-and down-ramp rate, penalty of five times frequency regulation), the value of a 1 % operating reserve is about half of the value of the energy. But under the preferred ramp limitation of 40 % per 15-min time step, the value of the operating reserve is negligible because the ramp limit is normally encountered only during wind curtailment, when wind generators can already control their ramp rate. Thus, curtailment to produce a reserve does not appear to be a good strategy for wind plants under any of the scenarios examined. As with the value of storage, curtailment to produce a reserve might be more valuable if evaluated under shorter time scales, such as the frequency regulation services provided by wind generation in Ireland discussed in the introduction.

A.1 Curtailment to produce an operating reserve

The “curtailment to produce a reserve” operational strategy is modeled by assuming that a wind plant curtails its power output by a fixed amount (a percentage of nameplate capacity, in MW), in order to create a small operating reserve. When the wind drops off quickly, the wind plant can use the reserve to reduce the observed ramp rate, by increasing the actual power output closer to the potential power output. For example, a 100 MW wind plant could always curtail 1 % of the available wind power in order to buffer sudden drops in the wind. If this wind plant is producing at nameplate capacity, then a 1 % curtailment is 1 MW, and the wind plant’s actual output is 99 MW. If the wind drops suddenly to a level where the wind plant is only able to produce 95 MW, the wind plant can manage the power output change, keeping it to a 4 MW step change (rather than the 5 MW change without the intentional curtailment).

A.2 Use of energy storage

The energy storage option allows the wind plant to install a sodium sulfur (NaS) battery, which can then be used to either increase wind plant revenue or decrease variability. The NaS battery is modeled after the currently-available PQ modules produced by NGK Insulators, the only established supplier for this technology [22]. Because NaS batteries are commercially available only in a pre-defined modular form as noted above, their power-to-energy ratio is fixed. NaS batteries require a temperature of ~325 ˚C to operate and thus require a continual “maintenance power” to maintain that temperature (accounted for in this model). NaS batteries have a continuous power rating of 0.05 MW, and have a manufacturer-defined pulse power capability (also accounted for in the model) under which they can provide up to four times the normal power rating for 15 min, making their maximum power output 0.2 MW. NaS batteries were chosen as the energy storage technology because they are a relatively established energy storage technology, have an appropriate power to energy ratio for this application, are modular and appropriate to the scale of a wind plant, and have been utilized for wind integration in the past [10, 17, 22]. Table 4 shows the NaS battery properties used in the battery model.

Table 4

NaS battery properties examined and their base-case values

NaS battery parameter	Base-case value
Round-trip efficiency	80 %
Module energy capacity	0.36 MWh
Module power limit	0.2 MW
Module maintenance (heating) power	2.2 kW
Module capital cost	$240 K ($670 K/MWh)
Module fixed operating cost	$8 K/module-year ($22 K/MWh-year)
Length of capital investment	20 years

NaS batteries are assumed to be co-located with the wind plant and are operated to maximize revenue. While the batteries could be used with the goal of reducing power fluctuations, an energy storage owner is unlikely to do so unless it is either the most profitable mode of operation or they are directed to by market protocols. To maximize revenue, NaS batteries are charged whenever the apparent energy price to the wind plant (including subsidies and penalties) is below a fixed "charge price", and discharged whenever the effective energy price is above a fixed "discharge price". Between the charge and discharge prices, the storage does nothing. Several alternative storage operational strategies were examined, including adjusting the charge/discharge prices as a function of state-of-charge, season, day of the week, or prevailing energy price, but the resulting revenues were similar or lower than those from the simple model. The optimal charge and discharge prices are determined separately for each wind plant in each policy scenario using a genetic algorithm optimization that searches for revenue-maximizing values of the charge and discharge prices.

The operation of storage under perfect information is also examined and compared with the simple model described above. Under the perfect information model, at each time step the operator looks ahead at the wind output and energy prices over the next 24 h. The revenue-maximizing operation of the NaS battery over the next 24 h is calculated, but only the operation in the current step is retained. In other words, an entire day of battery operation is calculated in order to determine the charge/discharge level in a single time step. The operation of the battery is constrained to end the 24-h look-ahead period at the same charge state that it began with, though the boundary effect is insignificant because the NaS battery is able to charge and discharge several times over a 24-h period.

A genetic algorithm was used to determine the “charge price” and “discharge price” that resulted in the highest wind+battery revenue (Fig. 13). Both the charge and discharge price were relatively high, and were consistent across different market policy scenarios. Under the “no rules” scenario, the average charge price was $62/MWh, meaning that the NaS battery would charge whenever the energy price dropped below $62/MWh, and the battery would discharge only when energy price was above $175/MWh. The overall revenue was not very sensitive to changes in these values: a 10 % change in either parameter resulted in less than 1 % change in revenue. The elevated charge price kept the energy storage fully charged most of the time, and the battery was only discharged when the electricity prices were very high. This is because most of the revenue from the storage came during infrequent price spikes, and the optimal strategy was to maintain a high state of charge to capture all the possible revenue from a potential future price spike. This result is similar to Fertig and Apt’s finding that an optimally-dispatched compressed air energy storage system in ERCOT would store energy 91 % of the time and only discharge 3 % of the time, as it attempts to capture all of the potential value of price spikes [13]. Figure 13 provides an example of the battery output under perfect information and the simple “buy below/sell above” model.

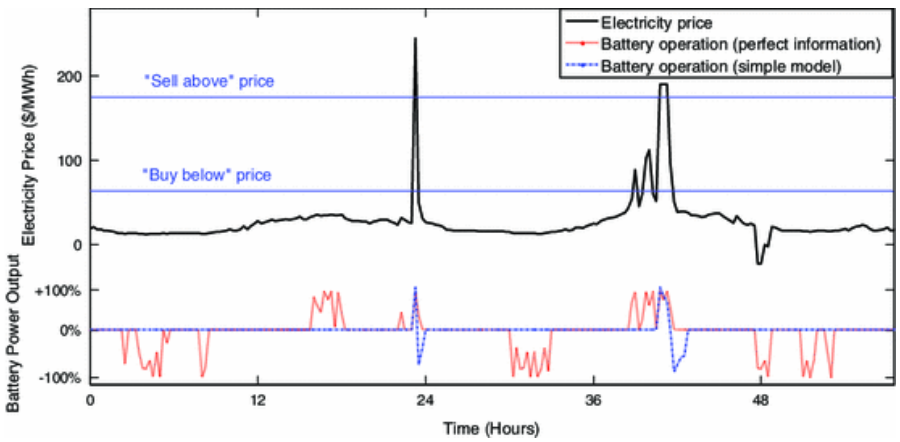

Fig. 13

Example of battery operation under perfect information and a simple “buy below/sell above” operation over 60 h. The “sell above” and “buy below” prices used for the simple model are shown in the *dashed lines* on the top part of the figure. The battery power output is shown in percent, from +100 % (full discharge) to −100 % (full charge). Under perfect information, the battery is able to extract value from smaller price changes (such as hour 17) while retaining enough energy for price spikes (hour 23), and charges when electricity price is lowest (hour 32). Under a simple “buy below/sell above” operation, the battery only discharges during relatively high price spikes and tends to recharge to capacity immediately afterwards

Without any wind-related market rules, where it is providing only time-shifting of wind energy, a NaS battery earns revenue equivalent to around 17 % of its annualized cost under a simple “buy below/sell above” operation, resulting in a large net loss. Under very strict rules, such as a 1 % up- and down-ramp limit and a penalty of five times the frequency regulation price, the value of a NaS module increases only a few percent to around 20 % of annualized cost. While there are other costs involved, the primary

contributor to annualized cost is the capital cost of the storage, which is $240 K per module or $700/kWh. Given the assumptions and limitations discussed above, NaS batteries only become a profitable investment for the wind plants at a cost of $120–$150 per kWh, even under the stricter scenarios discussed above.

The value of storage improves significantly if the battery is operated under perfect information, knowing the future prices and wind energy. This is due primarily to the ability to take complete advantage of energy price spikes in both the positive and negative direction. Under perfect information and a scenario where wind is not penalized for variability, a NaS battery recovers around 33 % of its annualized cost. This increases slightly to around 38 % under the strictest ramp-rate limitation. Even under perfect information, storage is profitable only if the cost is less than $250/kWh. While more advanced wind and price forecasting could make the operation of energy storage more profitable, most of the increased revenue from the perfect information operation comes from taking full advantage of price spikes, which are very difficult to predict [18, 24, 25, 29, 30].

Appendix B

In the scenarios with penalties for over-ramping or diverging from forecast, the penalties are based on the frequency regulation prices. This is done because frequency regulation prices reflect the willingness of generators to change their output levels, which changes over time. For example, if wind ramps up too quickly, other generators must ramp down to compensate. The regulation down price indicates the payments that a generator requires to perform this ramp-down. If generators are very willing to ramp down, then the regulation down price will be low and the wind plant will not be (and should not be) heavily penalized. Alternately, if wind picks up quickly in a period where generators are unwilling to ramp down, the wind generator will face higher penalties.

It is important to note that while frequency regulation prices are related to the ability of generators to ramp up and down over 15-min time steps, this is not how frequency regulation service is actually used. In the absence of an actual rapid response (5-min) ancillary service, frequency regulation prices are used as a substitute. The energy price is not included in the penalty scheme because any replacement energy is already paid from the market. For example, if a wind plant suddenly drops by 1 MW (over 1 h) and another generator ramps up 1 MW to compensate, the market will pay the prevailing energy price for the replacement MWh to the generator. Because 15-min penalty prices are required, the hourly frequency regulation prices are divided by four to generate four 15-min penalty prices for that hour. Penalties for over-ramping are assessed based on the change since the last time step, rather than changes since the last point where the wind plant was in compliance.

One relevant question regarding implementation of a ramp rate limit that has a large effect on both revenue and fluctuations is whether a wind plant's output should be tied to the most recent non-violation power output or if it should be tied only to the output in the prior time step. If the output of a wind plant is tied to the last point at which it did

not violate the ramp limit, then a wind generator is penalized for any energy delivered above the original ramp-up profile. Alternately, the wind generator output can be related only to the energy output in the previous step, and is thus charged an over-ramp penalty in only one time step (the difference in the two potential rules is illustrated more clearly in Fig. 14). This latter version of the rule is more forgiving towards over-ramping, and we find that it also results in much lower penalty charges to wind plants while having approximately the same effect on variability. From the system perspective, there is little reason to tie a wind generator's current power output to past power outputs (except the immediately past output). Throughout this work, the ramping constraints are tied only to the immediately prior power output, as this is better for both wind generators and the electricity system.

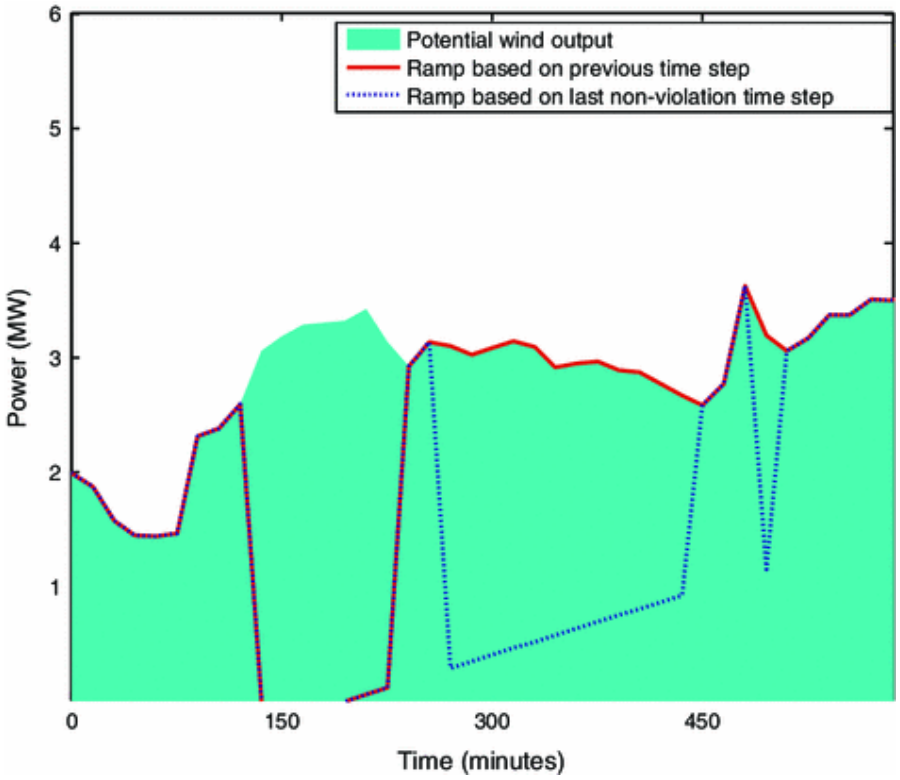

Fig. 14

Example output of a wind plant under two alternative ramping rules when only up-ramping is limited. The *dashed blue line* shows the output of a wind plant when the allowed power output is based on a fixed ramp-up from the last time step that did not violate the ramp limit. Under this rule, the wind plant is constrained to the ramp-up that starts around minute 200, and goes to full power output whenever the price of energy minus the penalty cost results in profit for the wind generator (around minutes 225, 450, and 500), but returns to the original line when energy price is no longer higher than the penalty. This can cause significant short-term variability, as wind output goes back and forth between the allowed ramp-up and maximum energy output. The *solid red line* shows the output of a wind plant when the allowed power output is the previous power output plus a limited up-ramp. When the wind plant violates the ramp limit at minute 225, it only pays the violation penalty during that time step and is no longer coupled to the original ramp-up line

Appendix C

C.1 The effect of different ramp rate limitations

It is natural to expect that using a much tighter ramp limitation should decrease variability significantly, though this was not found to be the case in the ramp rate-limited market scenarios that we studied. Figure 15 illustrates why a tighter ramp rate may result in little or no additional reduction in variability. Under any ramp rate limit, the wind plant will occasionally determine that the value of the available wind energy is greater than the penalty for violating the ramp rate, and ramp up to full power output. Under a tighter ramp limit, the power output of the wind plant will often be further from full output, resulting in a larger change in power output when the wind plants ramps up to full power. In general, using a tighter ramp limit results in fewer but sharper power output changes. Figure 15 is for a wind plant facing only an up-ramp limit, but the effect is very similar for a market scenario where wind plants have both up- and down-ramp limits.

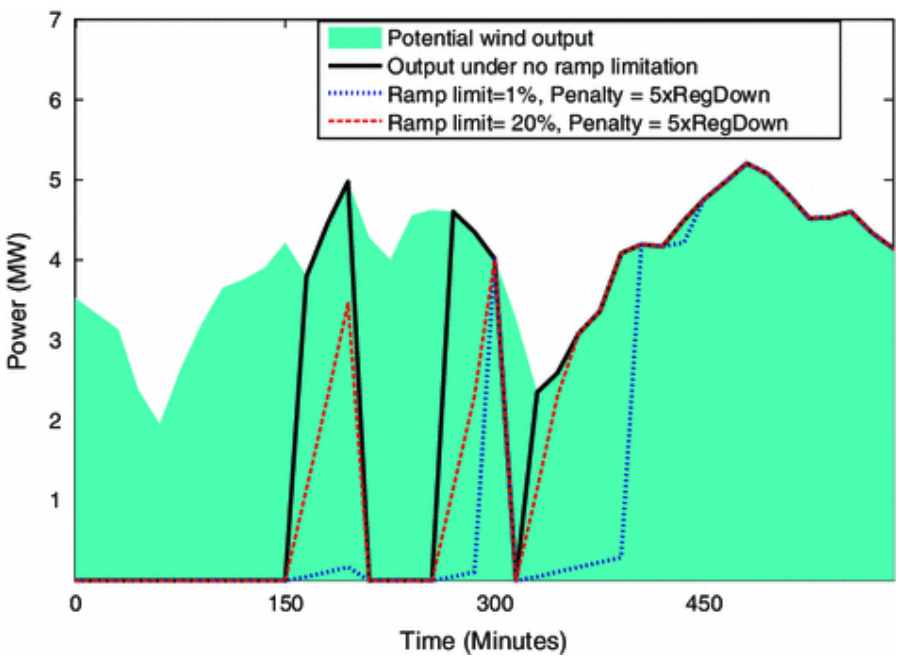

Fig. 15

Example wind power output under no ramping limit, an up-ramp limit of 1 % per 15-min time step, and an upramp limit of 20 % per 15-min step, showing why a tighter ramp rate limit can result in higher short-term fluctuations. At 180 min, the tighter ramp limit results in a much smaller change in power output than the 20 % ramp limit or no limit, as expected. At the point around minute 300 of this example, the 1 % ramp limit produces a sharper change in power output than the 20 % ramp limit. Under both ramp rates, the wind plant finds that the value of the available wind energy is greater than the penalty payment and decides to produce at

minute 300, but under a 1 % ramp rate the power output comes up from a much lower level. A similar sharp change can be seen for the wind plant under a 1 % ramp limit around minute 400, while the 20 % ramp rate scenario results in a more gradual increase

C.2 Underforecasting results

Figure 16 shows the average reduction in revenue and RMSE of wind plants under different deadband and penalty levels when underforecasting is permitted. When underforecasting is allowed, the situation is very different than when it is not permitted, as tighter deadband values with low penalties are best able to improve adherence to forecast while having little effect on wind revenue. This is because most wind plants use some amount of underforecasting and are better able to match a slightly diminished wind forecast. With underforecasting permitted, the improvements in RMSE are much better that when it is not permitted, resulting in a reduction in RMSE from 26 to 18 % with a wind plant revenue loss of around 1 %.

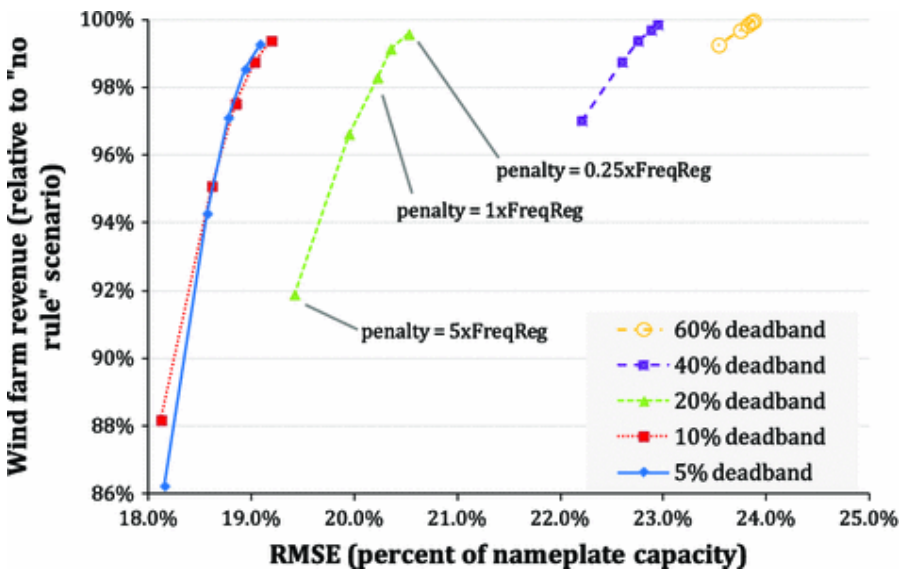

Fig. 16

Average change in revenue and RMSE of the collection of 16 wind plants under a market scenario where wind generators are penalized for diverging from the 6-h forecast and wind generators are permitted to report a smaller-than-actual capacity (underforecasting). RMSE is expressed as percent of the actual nameplate capacity

Figure 17 shows the RMSE and change in revenue for each wind plant in a market scenario where wind generators are penalized for diverging more than 10 % from the 6-hour forecast and underforecasting is permitted. The RMSE values for the 16 wind plants range over a factor of two, though small improvements are apparent for individual wind plants as the penalty is increased. The change in revenue is much less variable, though that variability increases as the penalty is increased. This is due to the natural ability of certain wind plants to better adhere to forecast.

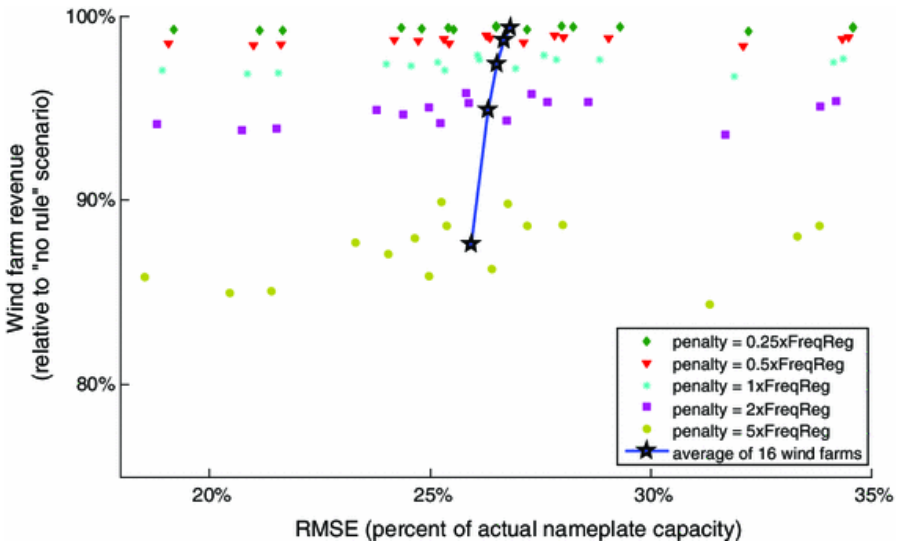

Fig. 17

Change in revenue and RMSE for 16 wind plants under a market scenario where wind generators are penalized for diverging from the 6-h forecast and wind generators are permitted to report a smaller-than-actual capacity (underforecasting). The results shown are for a deadband of 10 %, similar to the left-most line in Fig. 2, though these RMSE values are for individual wind plants rather than the collection of wind plants. RMSE is expressed as percent of the actual nameplate capacity

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