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The impact of wind power on electricity prices

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ABSTRACT

This paper investigates the impact of wind power on electricity prices using a production cost model of the Independent System Operator – New England power system. Different scenarios in terms of wind penetration, wind forecasts, and wind curtailment are modeled in order to analyze the impact of wind power on electricity prices for different wind penetration levels and for different levels of wind power visibility and controllability. The analysis concludes that electricity price volatility increases even as electricity prices decrease with increasing wind penetration levels. The impact of wind power on price volatility is larger in the shorter term (5-min compared to hour-to-hour). The results presented show that over-forecasting wind power increases electricity prices while under-forecasting wind power reduces them. The modeling results also show that controlling wind power by allowing curtailment increases electricity prices, and for higher wind penetrations it also reduces their volatility.

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1. Introduction

This paper investigates the impact of wind power on electricity prices. The analysis is performed using a production cost model of the power system operated by the Independent System Operator – New England (ISO-NE). Different scenarios are modeled to evaluate the impact of wind power on electricity prices for different wind penetration levels and for different levels of wind power visibility and controllability.

Wind power has greatly increased its share in the electricity generation mix during the past decade and it represents the variable renewable energy source (RES) with the highest total installed capacity around the world. In 2003 global wind power capacity amounted to 39 GW, compared to 318 GW in 2013 [1]. The great deployment of wind has been largely driven by policies to promote zero-emission electricity generation technologies with the goal of reducing greenhouse gas emissions. The increased production and deployment of wind turbines has led to a significant reduction in their capital cost. The U.S. Energy Information Administration projects that onshore wind entering service in 2018 will be one of the electricity generation technologies with the lowest total system levelized cost [2,3].

For a number of political, social, and economic reasons, wind penetration is expected to keep increasing significantly in the coming decades in many power systems around the world. Due to its negligible variable electricity generation cost, large wind penetrations will lead to several changes to the way in which electricity markets are presently operated. The impact of wind power on electricity prices has already been observed during the past years. Several electricity markets have seen negative electricity prices during periods of high wind power electricity production. Germany, for instance, has experienced negative electricity prices during moments in which wind and solar power combined represented a very large share of the instantaneous electricity generation mix. At 1 pm on Sunday May 11th 2014, wind power peaked at 21 GW while solar simultaneously generated 15 GW, at a moment in which the German power demand was only 59 GW. That day, Germany experienced negative electricity prices for 5 h during the afternoon [4]. Negative electricity prices are becoming more and more common in Germany. "For the first time in the history of the German power market, high amount of solar and wind generation, as well as must-run units and inflexible base load such as nuclear power, coupled with lower demand, has led to negative daily average wholesale electricity prices on two Sundays in the first half of 2014" [5]. Australian experiences have shown that a large increase in wind and/or solar power generation can lead to short-term negative electricity prices even at much lower penetrations of wind and solar power compared to Germany. Australia experienced negative electricity prices during the middle of a weekday, proving that negative electricity prices do not only happen during

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night when electricity demand is lowest [6].

Variable RES with negligible variable electricity generation cost, such as wind and solar power, shift the supply curve due to the merit order effect causing lower electricity prices, for instance, when wind blows or the sun shines. Other sources of electricity generation with negligible or low variable electricity generation cost, such as hydro and nuclear power respectively, also impact the merit order. However their impact on the electricity supply curve is not as variable and uncertain as in the case of wind and solar power. The share of wind and solar power in a power system's electricity generation mix cannot be perfectly forecasted and it varies at every time scale, from minutes, to days, to seasons. The impact of wind and solar power impact the planning and operation of a power system in all its facets and at every time scale. In addition to the merit order effect, wind and solar power impact electricity prices due to all the changes that they cause in the operation of the power network and the electricity market. The changes to the operation of the power system include, among other, the need for additional operating reserves [7,8], the capacity factors and the ramping of conventional generators, and the electricity exchanges with neighboring regions. For instance, Nicolosi [9] concludes that increasing variable RES leads to a reduction in the utilization of conventional power capacity. In addition, Brancucci Martínez-Anido and Hodge [10] show how increasing wind penetration increases ramping of most conventional generators and it reduces imports and increases exports of electricity.

Several past research efforts have modeled the impact of wind and solar power on electricity prices in different electricity markets. For instance, Suomalainen et al. [11] present a novel approach to analyze associations between intermittent energy sources, namely wind and hydro power, and electricity demand and prices in New Zealand. Pereira and Saraiva [12] study the impact of wind power on electricity prices in Spain and Portugal using a long term generation expansion model. J.M. Morales et al. [13] propose a simulation methodology to asses quantitatively the impact of an increasing integration of wind power on electricity locational marginal prices (LMPs). The authors conclude that “an increasing amount of wind power integration results in lower LMPs throughout the network until bottleneck appear”, and that “a high correlation among wind plants has an important impact on LMP volatilities” [13].

On the other hand, several publications perform empirical analyses of the impact of wind power on electricity prices. For example, C.K. Woo et al. [14] analyzed empirical power market data and showed how wind generation in Texas tends to reduce the level of spot prices, while also enlarging the spot-price variance. Ben Amor et al. [15] perform an empirical analysis of wind power on hourly electricity prices in Ontario, Canada. Their main contribution is the accounting of internal grid congestion in the analysis. Similarly, Clò et al. [16] present an empirical analysis of the impact of wind and solar power on electricity prices in Italy. Forest and MacGill [17] employ econometric techniques to empirically analyze the impacts of growing wind penetrations in the Australian Electricity Market. Likewise, Ketterer [18] studies the impact of wind power on day-ahead spot electricity prices in Germany. All the cited publications agree on the fact that wind power reduces electricity prices to a certain extent. Some of them also conclude that electricity price volatility increases with wind power penetration. O'Flaherty et al. [19], which analyzes the impact of wind energy penetration on the price of electricity in Ireland, instead, conclude that increases in wind penetration in recent years have not affected the relationship between wholesale electricity prices and UK gas prices.

The goal of this study is to model the impact of wind power on the operation of the power system, with the goal of capturing and analyzing the impact of wind power on electricity prices for different wind penetration, visibility, and controllability levels. A production cost model of the ISO-NE power system is run for several scenarios in order to analyze the impact of wind power on electricity prices under different wind integration conditions. The impact of distributed wind power on bulk power system operations has been analyzed and discussed in a recent publication from Brancucci Martinez-Anido and Hodge [10]. However, the analyzed scenarios in this study differ in terms of wind penetration, wind forecasts, and wind curtailment. Apart from the different electricity market and network analyzed, this paper mainly differs from published studies in terms of the different wind power integration conditions (in terms of curtailment and forecasting) under which the impact of wind power on electricity prices is analyzed.

The paper is structured as follows. Section 2 presents the model used to perform the study, and it describes the model validation with the purpose of analyzing electricity prices. It also describes and justifies the different modeled scenarios. Section 3 presents and discusses the simulation results. Finally, Section 4 concludes and suggests potential future research questions raised within the study presented in this paper.

2. Methodology

The production cost model of the ISO-NE power system used for this study was described in detail by Brancucci Martinez-Anido and Hodge [10]. This section is structured in three parts, the first provides a description of the model, the second discusses the validity of the model to answer the posed research question, and the last part describes and justifies the different modeled scenarios.

2.1. Model description

The model used to simulate the bulk system operation of the ISO-NE power system was developed using PLEXOS, a commercial production cost model. The base transmission and generation data included in the model was initially provided by the Eastern Renewable Generation Integration Study [20]. The model was initially developed to study the impact of distributed wind on transmission-level system operations, and we will refer to it throughout this paper as the ISO-NE model. The model is capable of simulating three electricity markets: day-ahead (DA), four-hour-ahead (4HA), and real-time (RT). The 4HA electricity market represents a potential future intra-day market as well as the security-constrained unit commitment at the last timescale useful to recommit gas combined-cycle (CC) power plants as well as gas and oil steam turbines (ISO-NE does not currently have an intra-day electricity market). The DA and 4HA markets are modeled with 1-h time steps, while the RT market is modeled with 5-min time steps. DA and 4HA load and wind power forecasts are used when modeling the corresponding DA and 4HA electricity markets. Nuclear, coal, biomass, and hydro power plants are committed in the DA market, while CC and steam power plants are committed in the 4HA market.

The ISO-NE model runs a DC optimal power flow (DC-OPF) in which the thermal limits of the transmission lines at voltage levels equal or higher than 69 kV are enforced. The electricity exchanges with the neighboring power systems (Hydro Quebec, New Brunswick, and New York) are modeled endogenously with a methodology that takes into consideration DA and RT locational marginal pricing in the neighboring nodes, as well as historical maximum flows from and to ISO-NE. Moreover, the ISO-NE model provisions contingency (only spinning) and regulation (both upward and downward) operating reserves.

The load and meteorological data (in this case including wind and hydro data) both represent the year 2010 in order to consider any potential correlations. The total electricity load in New England in 2010 was 131 TWh, with a peak load of 27 GW. The conventional generator data (excluding wind and solar power) also represents the generation fleet in use in ISO-NE in 2010. Generator maintenance is only considered for nuclear power plants. Solar power is not included in the model due to the negligible solar installed capacity in ISO-NE in 2010. Wind power is included with four different potential wind penetration levels. Details on the wind penetration, as well as wind forecast and wind curtailment are given in Section 2.3.

2.2. Model validation

The ISO-NE model has been validated by comparing the RT market results with 2010 data published by ISO-NE [21]. The electricity generation mix from the ISO-NE model is similar to the one observed in ISO-NE in 2010. The small differences in the electricity generation mix among the model results and the published data do not impact the applicability of the model, which realistically represents the operational characteristics of the ISO-NE power system.

In addition, the ISO-NE model has been validated in detail with regards to the hourly electricity prices published by ISO-NE. For validation purposes, the RT market is run with 1-h (in addition to 5-min) time steps. Table 1 shows a summary of key measures of electricity prices in ISO-NE in 2010 as a result of the ISO-NE model, as well as from published data.

Table 1 shows that the 2010 mean hourly electricity price simulated by the ISO-NE model is 4% lower than the observed value when the RT market is run with a 1-h time step. In the case of 5-min time steps, the difference is less than 0.6%. The standard deviation of the mean hourly electricity prices is also very similar between the model results and the published data, especially when the RT market is run with 5-min time steps. The ISO-NE model simulates the volatility of electricity prices (defined as the hour to hour change in electricity price) to a somewhat lower extent than what is observed in historical data. Nonetheless, when the RT market is modeled with 5-min time steps (compared to 1-h time steps), the resulting mean hourly volatility of electricity prices increases and gets closer to the one observed in the historical data. The standard deviation of the hourly volatility is smaller and higher compared to the published data when the RT market is run with 1-h and 5-min time steps respectively.

During 75% of the hours, the differences among the hourly electricity prices observed in ISO-NE in 2010 and the prices simulated by the ISO-NE model are lower than 10%. Moreover, for the same percentage of hours, the differences are lower than 10 $/MWh. Fig. 1 shows the load duration curve for the RT electricity prices in 2010 as published by ISO-NE and simulated by the ISO-NE model with 1-h time steps. The two curves are very similar and they coincide for the majority of the hours in the year. The accurate simulation of electricity prices is heavily driven by the LMP's in the neighboring regions due to the fact that ISO-NE is a heavily interconnected power system.

The accurate and validated simulation of electricity prices confirms that the operational characteristics of the ISO-NE power system are well simulated by the model. We believe that the model is therefore a valuable tool to study the impact of wind power on electricity prices. Fig. 2 shows a period of time in which electricity prices are modeled in a very precise manner; valleys and peaks are accurately represented by the model.

2.3. Scenarios

In order to study the impact of wind power on electricity prices, the ISO-NE model is run for 25 different scenarios in terms of wind penetration, wind forecasts, and wind curtailment. One scenario represents the ISO-NE power system with no wind power. The other 24 scenarios represent different wind integration conditions (with different combinations of wind forecasts and wind curtailment) for four wind penetrations (4.96%, 8.62%, 15.6%, and 21.2% on an annual energy basis):

- no wind forecast & no curtailment
- no wind forecast & curtailment
- wind forecast & no curtailment
- wind forecast & curtailment
- perfect wind forecast & no curtailment
- perfect wind forecast & curtailment

The six different wind integration conditions are modeled in order to analyze different conditions in terms of the visibility and control that the system operator has over the turbines. The model is run without wind forecasts, with state-of-the-art DA and 4HA operational forecasts, and with perfect wind power forecasts. In addition, the model is run allowing wind power curtailment, as well as without allowing it. The six combinations of the two wind integration conditions are compared with each other and with the case without wind power in order to investigate the impact that wind power has on electricity prices under different operational technology scenarios. Some of the scenarios combine unrealistic conditions (e.g. perfect wind power forecast scenarios, and allowing curtailment when wind forecasts are not considered), but modeling them as such helps in understanding the impact that both forecasting and curtailment have on wind power integration.

Fig. 3 shows the ISO-NE power system topology as well as the wind site locations for the 15.6% wind penetration scenario. Red dots represent transmission nodes, and green dots represent wind sites. The black lines among the red dots represent transmission lines.

The model used in this study was originally developed to study the impact of distributed wind on bulk power system operations, and therefore wind power is assumed to be distributed and connected to transmission nodes with load and with a voltage level equal to or lower than 69 kV. Given the unavailability of distribution network data, 69 kV is assumed to be the voltage level at which the transmission and the distribution networks intersect. The distributed nature of wind power in the model does not impact the results when analyzing the impact of wind power on electricity prices given the range of wind penetrations analyzed, the selection of nodes at which wind is connected, and the resulting irrelevant

Table 1
ISO-NE model validation – electricity prices in 2010.

	ISO-NE published data (hourly)	Model results (hourly)	Model results (hourly average from 5 min)
RT mean price ($/MWh)	49.56	47.60	49.30
Standard deviation RT price	24.78	19.28	25.87
Mean RT price 1-h volatility	7.21	5.49	6.04
Standard deviation RT price 1-h volatility	14.21	10.89	18.48

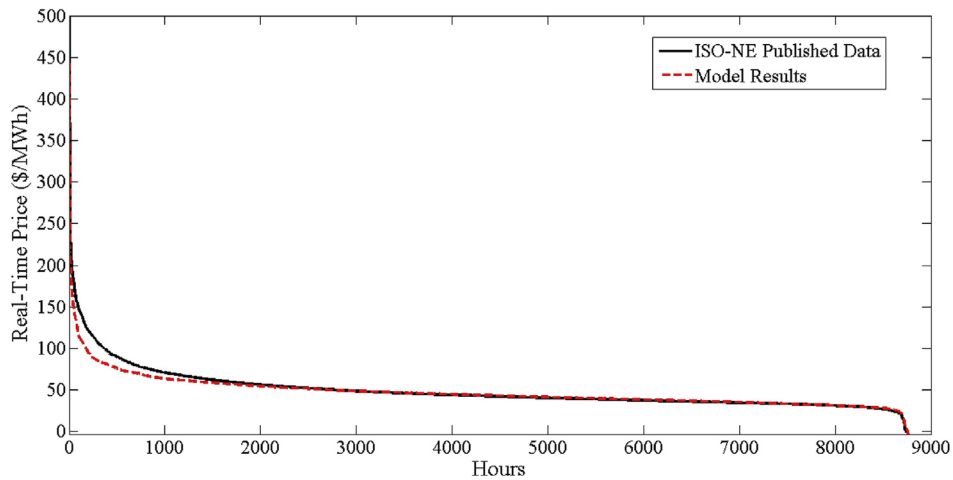

Fig. 1. ISO-NE model validation – load duration curve of RT price.

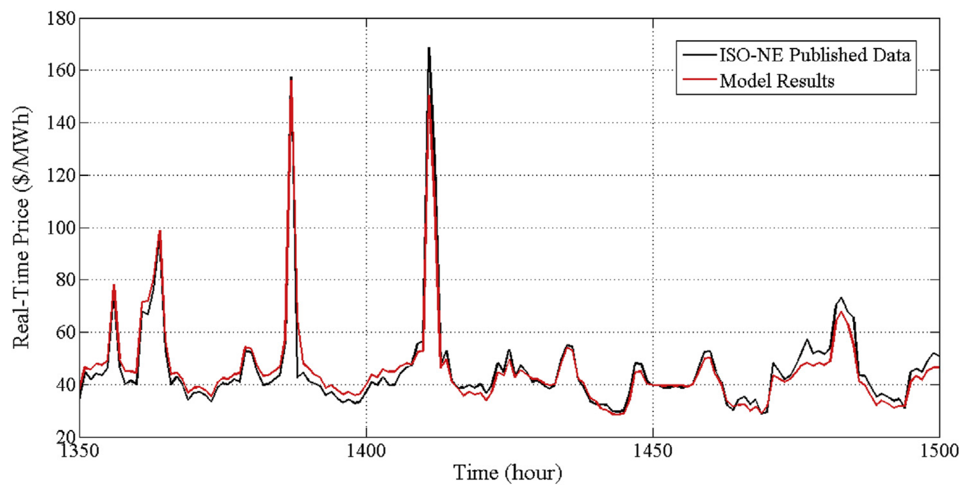

Fig. 2. ISO-NE model validation – electricity prices.

low-voltage line congestion due to wind power.

The wind data source is the recent Wind Integration National Data Set (WIND) Toolkit [22,23]. The four wind penetration scenarios represent subsets of the wind sites included in the WIND Toolkit (each with an installed capacity between 2 and 16 MW) and they have been designed taking into consideration network constraints, such as voltage level, as well as feeder rating and length. 5-minute actuals and hourly DA forecasts for each wind site are taken from the WIND Toolkit. 4HA hourly persistence forecasts have also been calculated to model the 4HA market.

3. Results

The 25 scenarios described in the previous section are run for a complete calendar year with the ISO-NE model, simulating the DA, 4HA, and RT markets. The results presented in this section are the outcomes of the RT market simulations. The impact of wind power on electricity prices is analyzed by looking at the mean, standard deviation, and distribution of the ISO-NE electricity prices and of their volatility. The RT market is modeled with 5-min time steps within the ISO-NE model. The 5-min RT electricity prices that result from the 25 different modeled scenarios have very high prices during very few time steps due to unrealistic penalties included in the model. In the case in which wind curtailment is not allowed, we assume a wind curtailment penalty equal to 50$/MWh (the optimization is run assuming a value of 1000 $/MWh, but we report the results with a minimum electricity price of −50 $/MWh). In other words, the ISO-NE electricity price results are post-processed in order to have an electricity price range between −50 and 500 $/MWh. The results are mainly presented using the hourly average of the 5-min electricity prices. However, results are also presented using 5-min electricity prices if there are any significant differences with respect to the hourly average.

3.1. Electricity prices

Fig. 4 shows the impact of wind power on the mean hourly electricity price for the different wind penetrations and wind integration conditions. Table S1 in the Appendix shows the numerical values shown in Fig. 4. The most obvious result is that wind power reduces the mean electricity price (a finding that was also seen in several publications, as detailed in the Introduction). The reduction in mean electricity price increases with wind penetration.

If wind forecasts are not considered in the DA and 4HA commitment runs, the mean electricity price is reduced to a much

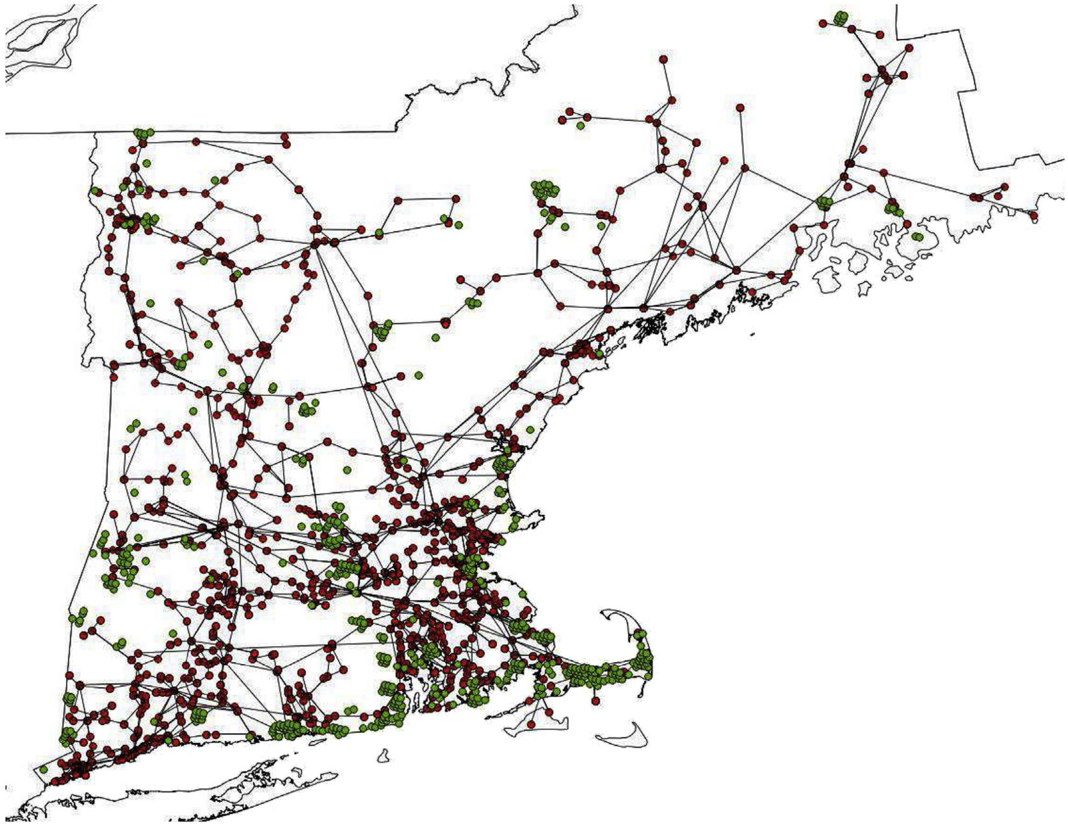

Fig. 3. ISO-NE power system topology with 15.6% wind penetration.

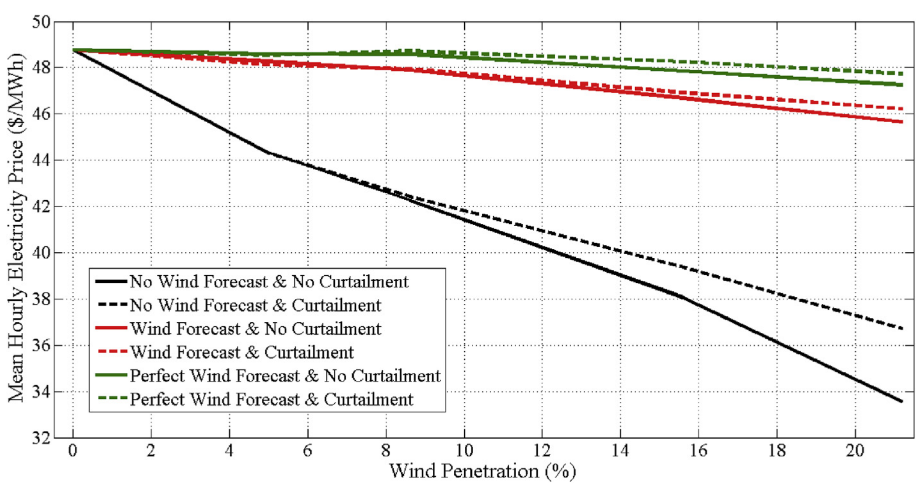

Fig. 4. Mean (Hourly) electricity price.

larger extent due to the over-commitment of generators in the DA and 4HA markets. In the RT run, the unexpected and unaccounted (in the DA and 4HA runs) wind power reduces electricity prices by turning off generators committed in the 4HA run and by shifting the supply curve to the right. Electricity exports are also increased to a larger extent because the ISO-NE power system cannot absorb all the unexpected wind power due to the ramping constraints and shut-down costs of conventional generators, especially the ones committed in the DA market. The mean electricity price is lower when state-of-the-art operational wind power forecasts are used compared to the case in which perfect forecasts are considered. The lower electricity prices are caused by the wind power forecast errors and the resulting re-dispatch of generation in the RT run. The difference in the mean electricity price between state-of-the-art operational wind power forecasts and perfect forecasts increases with wind penetration. The impact of under-forecasting is larger than the one of over-forecasting in terms of electricity prices (the wind power forecasts used do not have a bias). In other words, the relative reduction in electricity prices (due to over-commitment) when wind power is under forecasted is larger than the relative increase in electricity prices (due to under-commitment) when wind power is over forecasted. The main reason for this is that when wind power is under forecasted electricity prices may decrease to zero or negative values for long periods of time. While if wind power is over forecasted, electricity prices increase largely during short periods of time due to the ramping and start-up costs. Once conventional power plants have started up or their generation level has been ramped up largely, electricity prices stay high but much lower than when the generation mix is ramping to overcome the wind power over-forecasting event.

Fig. 4 also shows how the mean electricity price is lower when wind power curtailment is not allowed. In this case, the system must absorb all the wind power that was under forecasted. The difference in terms of mean electricity price between allowing and not allowing curtailment is explained for the three forecasting conditions by the increasing number of negative electricity prices when curtailment is not allowed, as it can be seen in Fig. 5. When wind power curtailment is not allowed, negative electricity prices are offered to absorb the wind power in excess, increasing electricity exports dramatically.

Fig. 6 shows the impact of wind power on the standard deviation of hourly electricity prices for the different wind penetrations and wind integration conditions. Table S2 in the Appendix shows the numerical values shown in Fig. 6. When state-of-the-art wind power forecasts are considered, the standard deviation of electricity prices increases with wind penetration. The latter is due to the more frequent ramping, starts, and shutdowns of conventional generators caused by wind power forecast errors. If wind power forecasts are not considered, the standard deviation of electricity prices is reduced significantly with the integration of wind power. The main reason is that the mean electricity price is considerably reduced and therefore the deviation from the mean is also reduced. However, if wind power curtailment is not allowed, the standard deviation increases as wind penetration increases. The latter is due to the increasing number of hours with negative electricity prices, as shown in Fig. 5. When wind power forecasting is considered in the DA and 4HA commitment decisions, allowing wind power curtailment does not have a consistent impact on the standard deviation of electricity prices as wind penetration increases.

Fig. 7 shows the distribution of hourly electricity prices for the case without wind power and for the 15.6% wind penetration for the three wind power forecasting scenarios in the case in which wind power curtailment is allowed. Fig. 8 shows the same for the case in which curtailment is not allowed. Wind power causes a larger number of low electricity price time periods, as can be observed from the thicker left tail of the distribution in the upper right graph in both Figs. 7 and 8. The peak of the distribution is higher and the left tail is thicker when wind power forecasts are not considered. The main difference when curtailment is not allowed is the very large number of hours with electricity price equal to −50 $/MWh when wind power forecasts are not considered. The unexpected excess wind power that cannot be curtailed causes a large number of negative electricity prices in order to respect the ramping constraints and avoid high shut-down costs of conventional generators.

3.2. Electricity price volatility

Fig. 9 shows the mean hourly electricity price volatility (defined as the annual average of the absolute hour to hour difference in electricity price) for the different wind penetrations and wind integration conditions. Table S3 in the Appendix shows the numerical values shown in Fig. 9. Wind power increases hour-to-hour electricity price volatility as wind penetration increases when wind power forecasts are considered. The rate of increase is higher when perfect wind power forecasts are considered. If wind power forecasts are not considered, wind power decreases electricity price volatility. As in the case of the electricity price standard deviation, the main reason is that the mean electricity price is considerably reduced and therefore the volatility of electricity prices is also reduced. However, if wind power curtailment is not allowed, the electricity price volatility increases as wind penetration increases. The latter is due to the increasing number of hours with negative electricity prices, as shown in Fig. 5.

Fig. 10 shows the mean 5-min (from one 5-min step to the next) electricity price volatility for the different wind penetrations and wind integration conditions. Table S4 in the Appendix shows the numerical values shown in Fig. 10. The impact of wind power on the 5-min electricity price volatility is very similar to the impact on hourly volatility. However, the relative impact of wind power on shorter term volatility (5-min versus 1-h) is much higher. For instance, for the case with 21.2% wind penetration, state-of-the-art wind power forecasts, and allowed curtailment (dashed red line (in web version)), the 5-min electricity price volatility is 22% higher compared to the case without wind power. For the same case, the hourly electricity price volatility, instead, increases by only 2%. Figs. 9 and 10 show that allowing wind power curtailment reduces electricity price volatility for the highest wind penetration scenario, 21.2%.

Figs. 11 and 12 show the distributions of the hourly and 5-

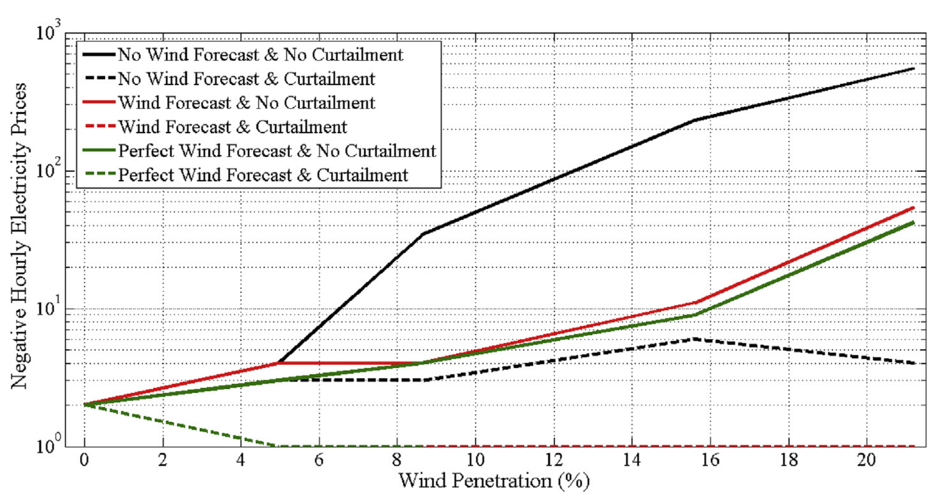

Fig. 5. Number of hours with negative (hourly) electricity prices.

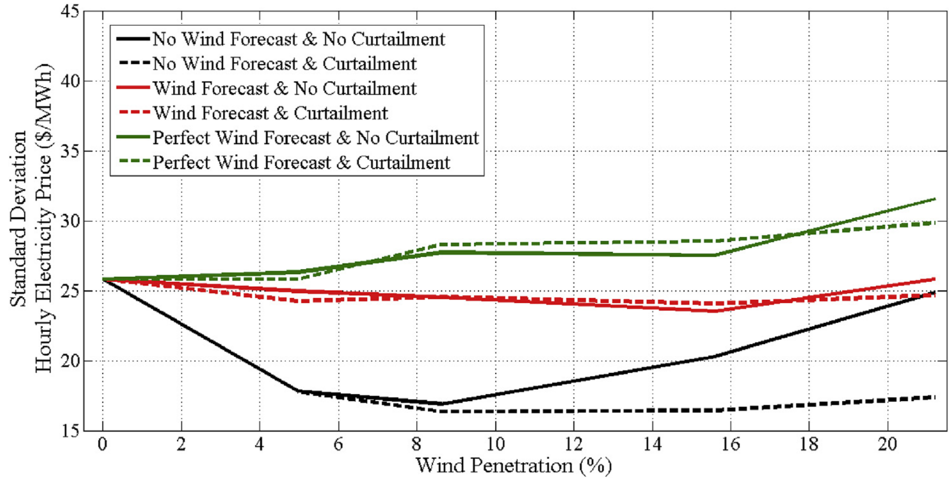

Fig. 6. Standard deviation (hourly) electricity price.

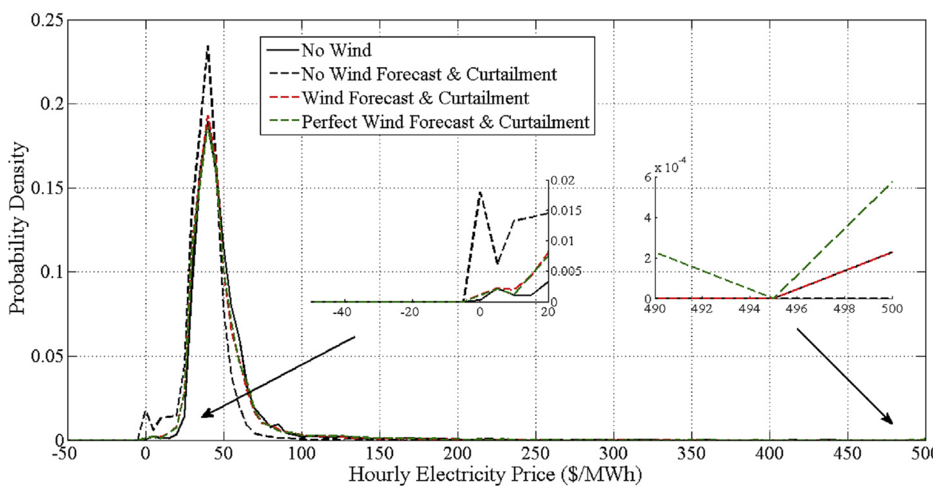

Fig. 7. Distribution of hourly electricity prices (curtailment).

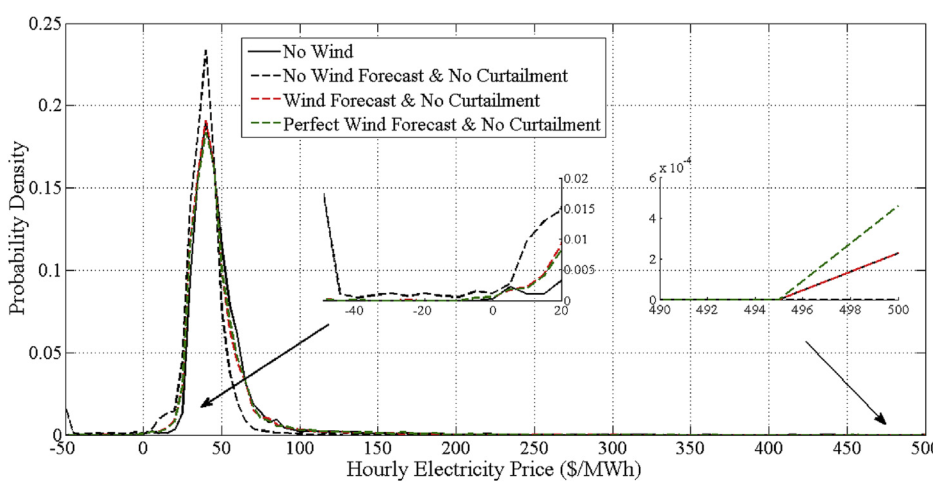

Fig. 8. Distribution of hourly electricity prices (no curtailment).

min absolute electricity price volatilities respectively, for the case without wind power and for the 15.6% wind penetration for the three wind power forecasting scenarios in the case in which wind power curtailment is allowed. Both distributions have very long and thin tails for all scenarios. As expected, the main difference between the two figures, as also shown in Figs. 9 and 10, is that the

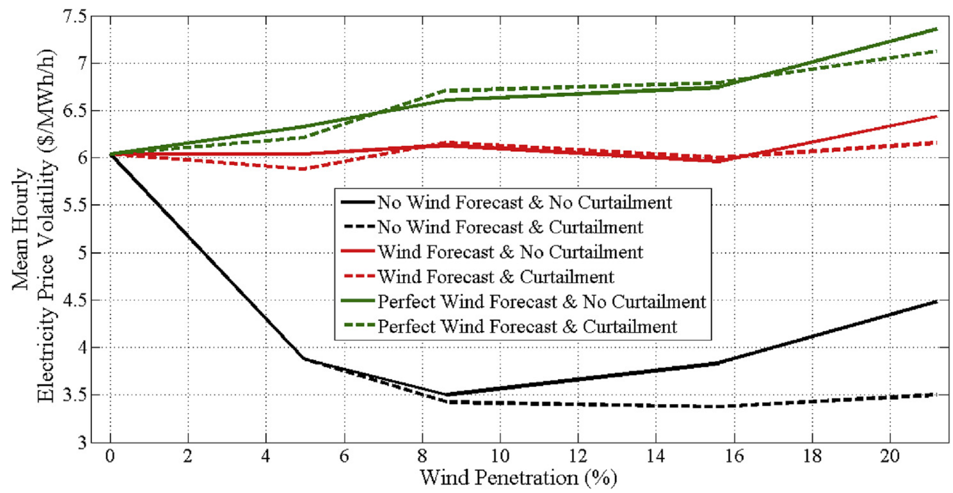

Fig. 9. Mean (hourly) electricity price volatility.

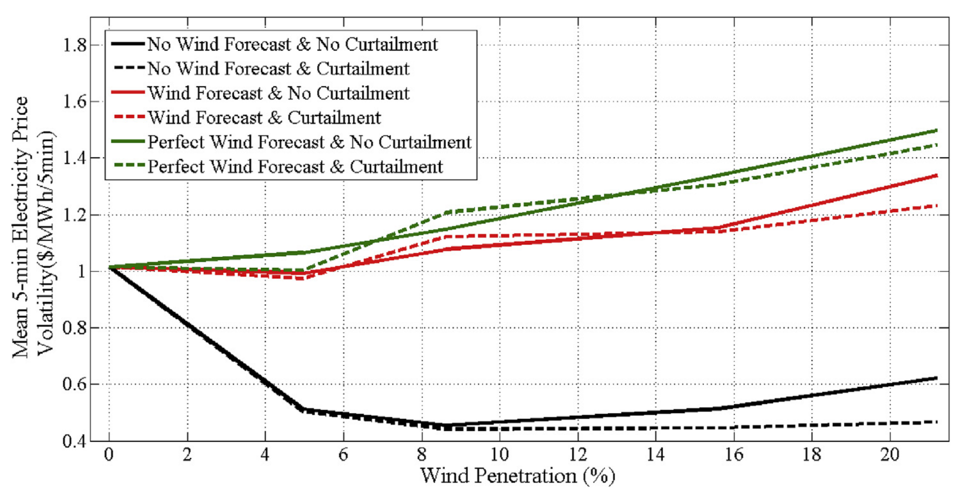

Fig. 10. Mean (5-min) electricity price volatility.

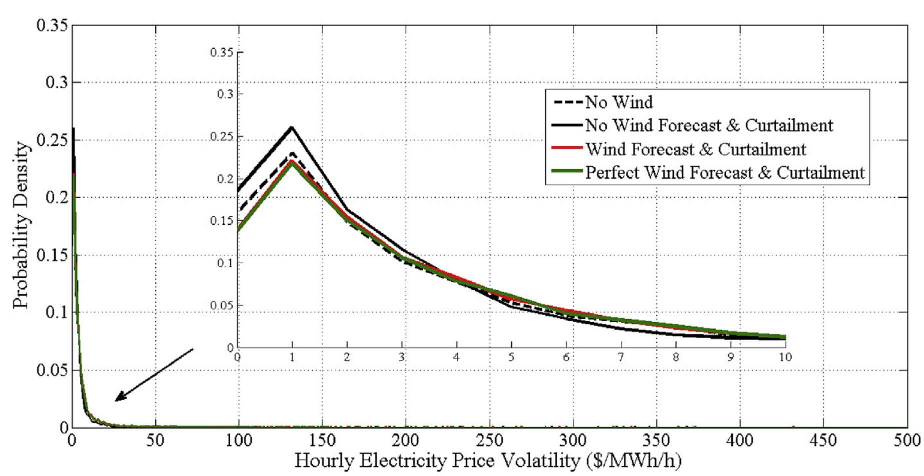

Fig. 11. Distribution of hourly electricity price volatility (curtailment).

5-min price volatility is much smaller than the hourly price volatility. Another considerable difference is that the distribution of the 5-min price volatility has a much higher and steeper peak.

3.3. 5-Day example

In order to better visualize and understand the results presented

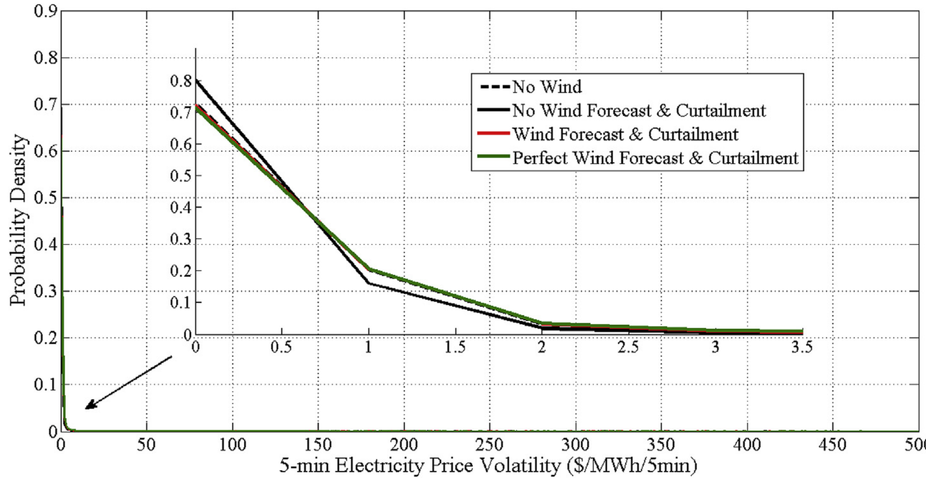

Fig. 12. Distribution of 5-min electricity price volatility (curtailment).

in sections 3.1 and 3.2, this section shows in detail how the electricity prices change in a 5 day-period, from 1 to 5 February 2010. This period has been chosen because it illustrates several impacts of wind power detailed in the previous sections. The operation of the power system is shown and described during the same time period. All the results are plotted with a 5-min time step. The results are given for the case without wind power and for the 15.6% wind penetration scenario. The results are shown for three wind integration conditions (no forecasts & no curtailment, forecasts & no curtailment, forecasts & curtailment). The first condition represents a very unlikely situation given the high wind penetration analyzed. However, it is important to compare the results with the other two scenarios (with wind power forecasts) in order to understand the impact of not considering wind power forecasts. The comparison of the two scenarios that consider wind power forecasts allow an investigation of the impact of allowing wind power curtailment, or in other words, of having control over the electricity generation of wind turbines.

Fig. 13 shows how the electricity price changes during the 5-day period for the four different scenarios. This time period has been selected because several impacts of wind power on electricity prices can be observed for different wind integration conditions. In Fig. 13, we can observed two periods (~hours 50–55 and hours 72–78) during which the electricity price is −50$/MWh for several hours when wind power forecasts and wind curtailment are not considered. As can be seen in Figs. 14 and 15, during these two periods, wind power production is relatively high (~4500–6000 MW) and load is relatively low (~below 13,000 MW). The resulting net load during these two periods is also very low (~below 8000 MW), as can be seen in Fig. 16. During these two periods, the system does not find a feasible solution without allowing wind curtailment. Therefore, the optimized system pays the wind curtailment penalty of 1000 $/MWh (prices are plotted as −50 $/MWh due to the post-processing of the results) and wind power is curtailed as shown in Fig. 17 (the green area above the blue (in web version) line on the upper right graph). A similar situation to the two situations just described can be seen around the 100th hour in Fig. 13. The net load is also quite low (~9000–10,000 MW) as shown in Fig. 16. In this case, electricity prices do not reach −50 $/MWh, but they are significantly lower when wind power forecasts are not considered compared to the other scenarios. As can be seen in Fig. 17, wind power is not curtailed during this period (the wind curtailment penalty is not paid). Electricity exports, hydro pumping, and the allowed reduction of conventional generators is

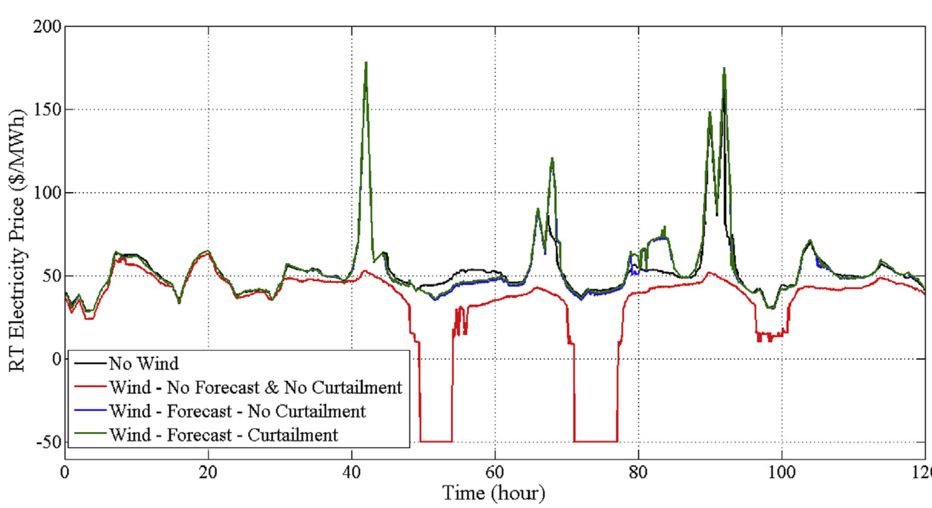

Fig. 13. RT electricity price (1–5 February).

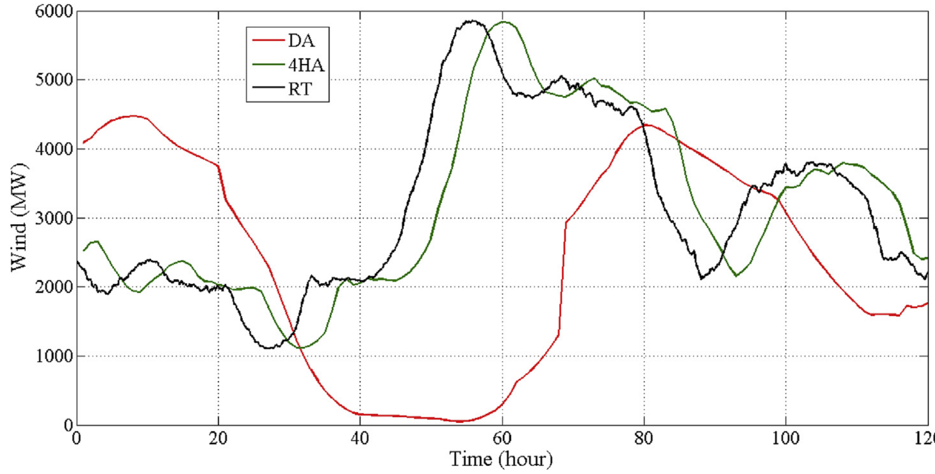

Fig. 14. DA, 4HA & RT wind power (1–5 February 2010).

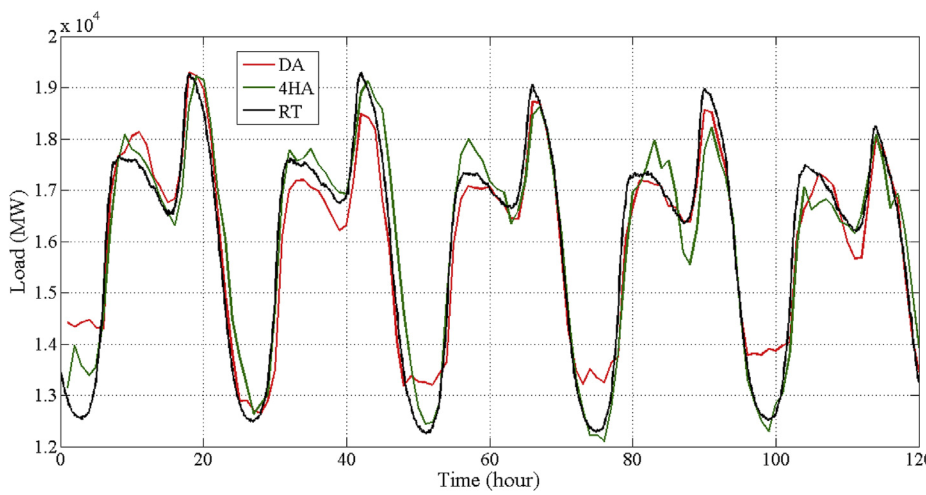

Fig. 15. DA, 4HA & RT load (1–5 February 2010).

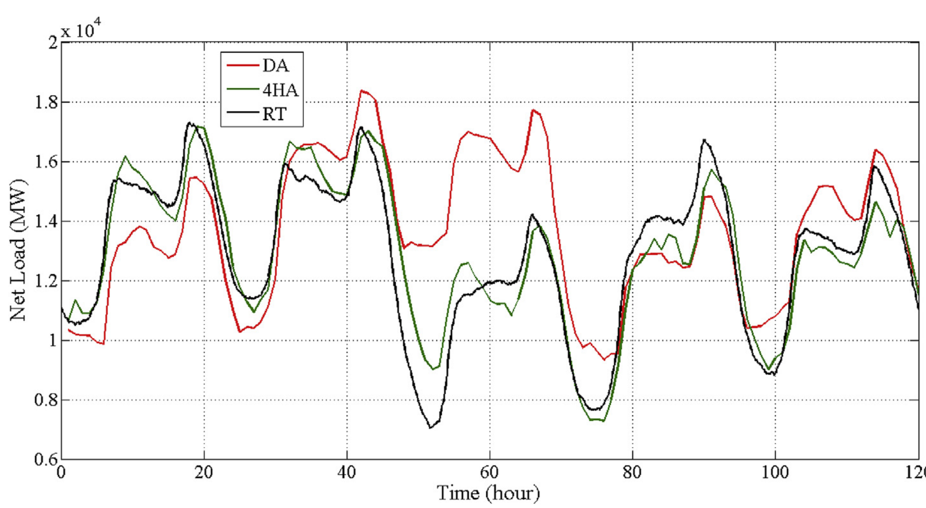

Fig. 16. DA, 4HA & RT net load (1–5 February 2010).

enough to compensate for the unexpected wind power. Table S5 in the Appendix shows the numerical values shown in Fig. 17.

During most of the 5-day period, the electricity price is very similar between the scenario without wind and the scenarios with

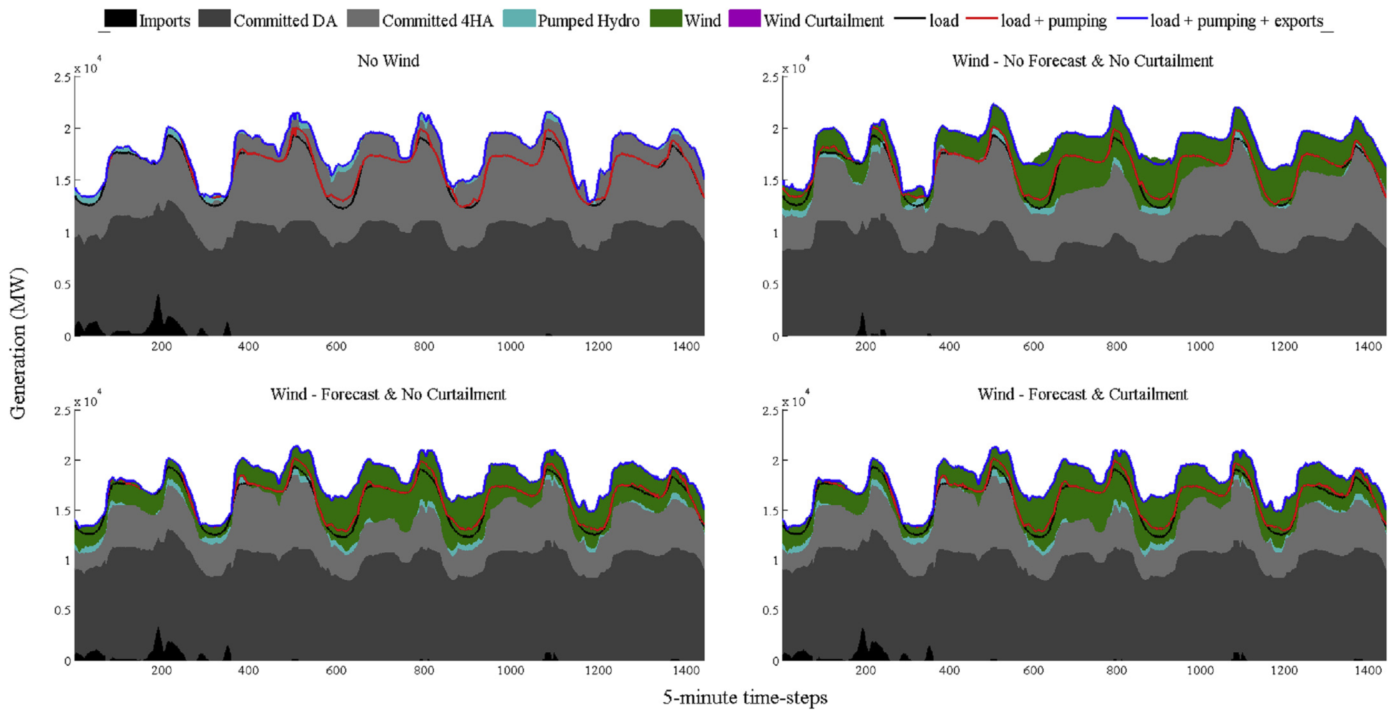

Fig. 17. Generation stack (1–5 February 2010).

wind that consider wind power forecasts, as can be seen in Fig. 13. However, there are two specific periods during which the electricity prices in the scenario without wind are significantly higher (~hours 50–60) and lower (~hours 80–85) than in the scenarios with wind that consider wind power forecasts.

In the first case (~hours 50–60), electricity prices are lower in the scenarios with wind due to the large wind generation and the very large DA wind power forecast error during the entire 10-h period and the large 4HA wind power forecast error during the first hours of the 10-h period (4HA persistence forecast errors are large during steep ramping of wind power), as can be seen in Fig. 14. The under-forecasting of wind power results in over commitment of electricity generation in the DA and 4HA runs. In the RT run, the under forecasted wind power reduces electricity prices by turning off generators committed in the 4HA run.

A similar behavior can be observed in Fig. 17 when comparing the two upper graphs that represent the scenario without wind and the scenario without wind power forecasts (in other words, a scenario with 100% under-forecasting of wind power). When comparing the two graphs we can see a large decrease in the gray area (generation committed in the 4HA run) in the scenario with wind and without wind power forecasts compared to the scenario without wind. Table 2 shows how coal-fired power plants are the power plant type committed in the DA run which are re-dispatched the most in the RT run, when wind power is under forecasted. In the case of generators committed in the 4HA run, CC power plants are the type that are shut-down and/or re-dispatched the most when wind power is under forecasted.

As can be seen in Fig. 17 electricity exports and hydro pumping are also largely increased in order to absorb the under forecasted wind power due to the ramping constraints and shut-down costs of conventional generators.

In the second case (~hours 80–85), instead, electricity prices are higher in the scenarios with wind due to the large DA and 4HA over-forecasting of wind power (as can be seen in Fig. 14). Over-forecasting wind power leads to the re-commitment and re-

Table 2
Generation committed and dispatched in DA and RT (1–5 February 2010).

Generation 1–5 Feb. '10 (GWh)	No wind		Wind – No forecast & No curtailment		Wind – Forecast & No curtailment		Wind – Forecast & curtailment	
	DA dispatch	RT dispatch	DA dispatch	RT dispatch	DA dispatch	RT dispatch	DA dispatch	RT dispatch
	Generation committed in DA							
Nuclear	585.36	585.36	585.36	579.63	585.36	585.36	585.36	585.36
Biomass	101.23	101.23	101.23	94.34	100.38	101.1	100.38	101.1
Coal	394.33	396.6	394.33	303.68	385.06	383.51	385.11	383.82
Hydro	140.41	140.29	140.41	140.29	140.41	140.28	140.41	140.28
Total	1221	1223	1221	1118	1211	1210	1211	1211
	Generation committed in 4HA							
Gas CC	801.61	805.35	801.61	648.68	473.64	471.53	471.03	468.77
Gas ST	35.28	40.19	35.28	33.87	17.71	21.94	18.23	22.5
Oil ST	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Total	837	846	837	683	491	494	489	491

dispatch of electricity generators with fast start-up and ramping capabilities. These types of generators have higher variable electricity generation costs which lead to higher electricity prices.

The only significant electricity price difference between the two wind scenarios with and without wind power curtailment (blue and green lines in Fig. 13) is during a very short period of time (~hours 79–80). This very short time period corresponds to a period during with a very steep and large net load increase, therefore a period during which the power system is under stress. The electricity price is higher when wind power curtailment is allowed. Even if it cannot be appreciated in Fig. 17, wind power is slightly curtailed (a few MW's) in the scenario in which wind power curtailment is allowed. This result confirms what is seen in Fig. 4, in which the mean electricity price is lower when wind power curtailment is allowed. In this short time period, even if it cannot be appreciated in Fig. 17, electricity exports are slightly higher when wind power curtailment is not allowed.

4. Conclusion

This paper presents a study that investigates the impact of very high wind power penetrations on electricity prices. The analysis is performed using a production cost model of the ISO-NE power system. Different scenarios in terms of wind penetration, wind forecasts, and wind curtailment are modeled in order to analyze the impact of wind power on electricity prices for different wind penetration levels and for different levels of wind power visibility and controllability.

The analysis of the outcomes of the simulations performed in the work presented in this paper result in the following conclusions. Electricity prices decrease and electricity price volatility increase with wind penetration. The impact of wind power on volatility is larger in the shorter term (5-min compared to hour-to-hour). If wind power is integrated in the power system without forecasting or without considering it in the generation commitment decisions, electricity prices will drop significantly due to the impact of high negative prices for conventional units unable to go past their minimum generation levels. Over-forecasting wind power increases electricity prices, while under-forecasting wind power reduces electricity prices. Having control over the electricity generation of wind turbines, or in other words, allowing wind power curtailment, increases electricity prices. The impact of allowing curtailment on electricity price volatility depends on the wind penetration level. For high wind penetrations, allowing wind power curtailment reduces electricity price volatility.

The results presented in this paper have led to several insights in terms of the impact of wind power on electricity prices. However, they have also paved the way for new research questions. Future work could, for instance, investigate how the impact of wind power on electricity prices changes in power systems with different market rules and different generation mixes. For instance, how would the results presented in this paper vary if the 4HA market is not considered and CC power plants are committed in the DA market? Or, how would the results vary if instead of modeling the power system of ISO-NE, which has a very large share of gas-fired power plants in the electricity generation mix, we would model a power system with, for instance, a higher share of base load generation?

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Appendix

Table S1
Mean (hourly) electricity price.

Wind penetration (%)	Mean (hourly) electricity price ($/MWh)			
0	48.77			
	No Forecast	**Forecast**	**Perfect Forecast**	**No Curtailment**
4.96	44.33	48.28	48.60	
8.62	42.26	47.88	48.59	
15.61	38.05	46.67	47.86	
21.21	33.55	45.64	47.26	
4.96	44.33	48.13	48.53	**Curtailment**
8.62	42.42	47.93	48.72	
15.61	39.35	46.91	48.25	
21.21	36.70	46.22	47.74	

Table S2
Standard deviation (hourly) electricity price.

Wind penetration (%)	Standard deviation (hourly) electricity price			
0	25.79			
	No Forecast	**Forecast**	**Perfect Forecast**	**No Curtailment**
4.96	17.80	24.96	26.31	
8.62	16.89	24.52	27.73	
15.61	20.28	23.50	27.50	
21.21	24.84	25.85	31.55	
4.96	17.79	24.26	25.82	**Curtailment**
8.62	16.33	24.56	28.27	
15.61	16.42	24.07	28.50	
21.21	17.36	24.66	29.84	

Table S3
Mean (Hourly) electricity price volatility.

Wind penetration (%)	Mean (hourly) electricity price volatility ($/MWh/h)			
0	6.04			
	No Forecast	**Forecast**	**Perfect Forecast**	**No Curtailment**
4.96	3.87	6.04	6.33	
8.62	3.50	6.13	6.61	
15.61	3.83	5.96	6.74	
21.21	4.48	6.44	7.36	
4.96	3.87	5.88	6.21	**Curtailment**
8.62	3.42	6.16	6.71	
15.61	3.37	6.00	6.79	
21.21	3.50	6.16	7.12	

Table S4
Mean (5-min) electricity price volatility.

Wind penetration (%)	Mean (5 -min) electricity price volatility ($/MWh/5min)			
0	1.01			
	No Forecast	**Forecast**	**Perfect Forecast**	**No Curtailment**
4.96	0.51	0.99	1.07	
8.62	0.45	1.08	1.15	
15.61	0.51	1.15	1.34	
21.21	0.62	1.34	1.50	
4.96	0.50	0.97	1.00	**Curtailment**
8.62	0.44	1.12	1.21	
15.61	0.45	1.14	1.31	
21.21	0.47	1.23	1.45	

Table S5
Generation (& Demand) Stack (1–5 February 2010).

(GWh)	No wind	Wind – No forecast & No curtailment	Wind – Forecast & No curtailment	Wind – Forecast & curtailment
Load	1917	1917	1917	1917
Imports	26	4	24	25
Generators committed DA	1223	1118	1210	1211
Generators committed 4HA	846	683	494	491
Pumped Hydro Generation	23	26	29	29
Wind	0	378	378	377
Wind Curtailment	0	0	0	0.42
Hydro Pumping	30	34	39	39
Exports	171	252	179	177

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