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Economic Evaluation of Short-Term Wind Power Forecasts in ERCOT: Preliminary Results

Preprint

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To be presented at the 11th Annual International Workshop on Large-Scale Integration of Wind Power into Power Systems as Well as on Transmission Networks for Offshore Wind Power Plants Conference
Lisbon, Portugal
November 13–15, 2012

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Conference Paper
NREL/CP-5500-56257
September 2012

Contract No. DE-AC36-08GO28308

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Economic Evaluation of Short-Term Wind Power Forecasts in ERCOT

Preliminary Results

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***Abstract*—A number of wind energy integration studies have investigated the monetary value of using day-ahead wind power forecasts for grid operation decisions. Historically, these studies have shown that large cost savings could be gained by grid operators implementing the forecasts in their system operations. To date, none of these studies have investigated the value of shorter term (0- to 6-h ahead) wind power forecasts. In 2010, the Department of Energy and the National Oceanic and Atmospheric Administration partnered to form the Wind Forecasting Improvement Project (WFIP) to fund improvements in short-term wind forecasts and determine the economic value of these improvements to grid operators. In this work, we discuss the preliminary results of the economic benefit analysis portion of the WFIP for the Electric Reliability Council of Texas. The improvements seen in the wind forecasts are examined and the economic results of a production cost model simulation are analyzed.**

Keywords-wind power forecasting; numerical weather prediction; economic value; grid operations

I. Introduction

Wind power forecasting is recognized as a key technology needed to aid in the integration of increasing penetrations of variable and uncertain wind power. Previous wind integration studies have shown the economic and reliability benefits of wind power forecasting for grid operators but have primarily focused on day-ahead forecasts needed for the unit commitment process [1–4]. The Wind Forecasting Improvement Project (WFIP) was formed as a partnership between the United States Department of Energy, the National Oceanic and Atmospheric Administration, private industry, and academia. It is unique in that it focuses on the potential value provided by improvements in very short-term wind power forecasts, defined here as between 0 and 6 h ahead. Within the meteorological community, it is commonly believed that increasing the number and quality of meteorological measurements assimilated into numerical weather prediction (NWP) models will have a positive impact on the quality of wind power forecasts derived from them. The WFIP was designed to test this assumption. Additional information on WFIP can be found in [5]. Fig. 1 shows the project region.

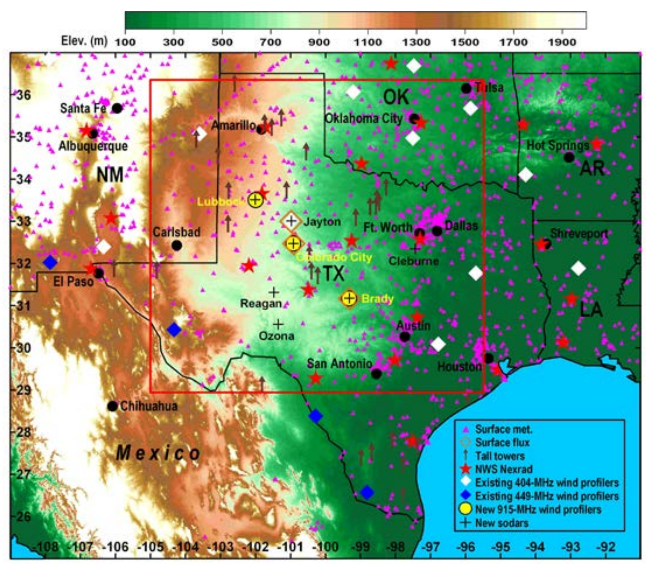

Figure 1. Southern study region and instrumenation.

II. Analysis Process

A preliminary analysis to understand the impact of improving accuracy of short-term wind power forecasts was performed using production simulation software. The tool used was GE-MAPS (MAPS) [6], which is a security-constrained unit commitment and dispatch model simulating the operation of a locational marginal price (LMP)–based power market. MAPS simulates the hour-by-hour operation of the power market, committing and dispatching generating units to meet hourly system load with the objective of minimizing overall system production cost subject to generating unit constraints (such as minimum up-/down-times, minimum and maximum capacity levels, etc.), transmission constraints (including DC-based power flow and contingency constraints), and other system constraints (such as operating reserves). System production cost is defined as the sum of fuel costs, variable operation and maintenance costs, start-up costs, and emission costs for all generators that are chosen to provide energy. Wind generators in MAPS were modeled using hourly wind shapes and assumed to have a zero variable cost.

The key direct benefits because of improved accuracy of short-term forecasts are reduced system production costs because of more efficient commitment of medium-start generators (e.g., with start-up times less than 6 h) and reduced curtailment of wind generation. Other potential benefits include reduction in energy imbalance cost because of possible decrease in penalties paid by wind generators that deviate from forecast (applicable in markets that allow participation in the day-ahead and real-time market by wind units with energy imbalance fulfillment requirements), decreases in total wholesale electricity price paid by demand (otherwise known in this paper as load payment costs/cost to serve load), and possible reductions in NO_x emissions and unit start-ups, depending on specific changes in unit commitment and dispatch decisions in response to changes in wind forecasts.

Using MAPS, the system benefits mentioned above were estimated for the impact of an improved 6-h-ahead wind forecast for an historical six-month period, from October 2011 to March 2012. This analysis was performed for the Electric Reliability Council of Texas (ERCOT). First, MAPS was run using day-ahead wind forecasts. Then, MAPS was run twice—once with the old 6-h-ahead wind forecasts and then with the new and more accurate 6-h-ahead wind forecasts. In both of these runs, the commitment patterns of generating units with start-up times greater than 6 h were fixed. In ERCOT, these units were the nuclear units and primarily large coal and large steam, oil, and gas units. The generating units that were allowed to change their unit commitment status in MAPS were those with minimum down times of less than or equal to 6 h because these were the units that can respond, if needed (by turning on or off), to accommodate the new 6-h wind forecast. Those units whose commitment status was allowed to change to the 6-h forecasts were primarily combined-cycle units, combustion turbines, and some small steam units. Once the commitment was revised to consider the impact of the 6-h forecasts, unit dispatch was performed in MAPS utilizing the actual output of wind generators.

Another benefit from improved short-term wind power forecasts is the cost savings from the reduced need to carry operating reserves. In 2008, ERCOT completed a study evaluating the impacts that high wind penetrations would have on operating reserve requirements [7]. Requirements for various reserve categories in ERCOT are now based on the wind power penetration and its associated impact to wind power forecast errors [8]. In WFIP, we focus on the impact to non-spinning reserve service, which is the most impacted by short-term forecast errors of wind.

III. SHORT-TERM FORECAST ACCURACY IMPROVEMENT

Before looking at the economic benefits from the production cost simulation process, it is instructive to understand the forecast improvements for the six-month period and their variations in space (between various wind generators) and time (during a day/week). It is also useful to look at a brief statistical analysis of improved wind forecasts to understand error distributions.

Fig. 2 shows a sample of the improvements in forecast for various wind generators (as a percent of their installed capacity) and the net improvement if the output from those wind generators were aggregated.

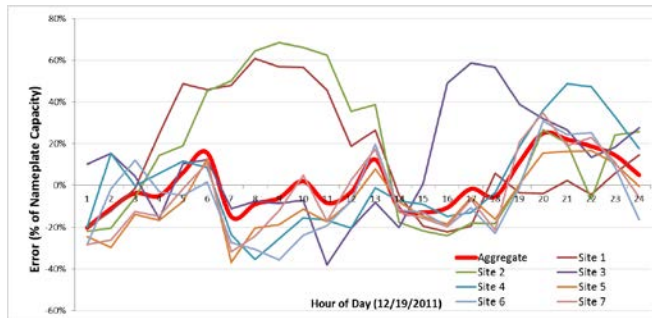

Figure 2. Benefits of aggregation.

A few observations can be made from Fig. 2. First, at any point in time there are generally a few wind generators with outputs that are over-forecast and a few wind generators with outputs that are under-forecast. Therefore, although individual wind generators can have relatively high forecast errors, the aggregate forecast error can be quite low. This is shown in Fig. 1, which is a visual comparison of the variations in error for each of the sites versus the variation of the aggregate curve. The lower overall error in the aggregate wind forecasts was because of the net sum of the under-forecast and over-forecast errors for individual wind generators. It is important to note that in the production simulation process, to create the net hourly load at each bus the outputs of wind generators (either forecast or actual) are subtracted from load at the bus at which the wind generator is interconnected. Hence, barring transmission constraints between individual wind generators, the system simulations (and system operations, in reality) will see the error of the aggregated curve shown in Fig. 2 and therefore could see correspondingly less forecast errors than those for individual wind generators. Fig. 3 and Table 1 and Table 2 show a summary statistical description of the overall improvements in short-term forecasts at a system level by aggregating the forecasts for all wind generators.

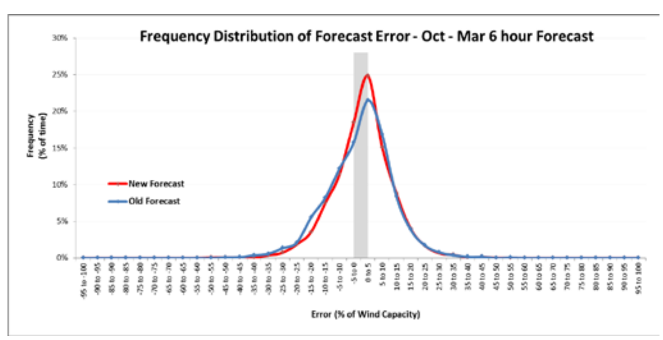

Figure 3. Distribution of 6-h forecast errors (old and new) for the 6-month period.

TABLE I. STATISTICAL SUMMARY OF OLD AND NEW FORECASTS (ERROR AS % OF CAPACITY)

	Percent Error (% of Total Wind Capacity)					
	Mean Absolute Error (%)			*Standard Deviation (%)*		
Month	***New***	***Old***	***Improve-ment***	***New***	***Old***	***Improve-ment***
October	6.8	8.6	-1.7	6.3	7.1	-0.7
November	6.6	7.4	-0.8	5.6	6.3	-0.7
December	8.6	9.1	-0.6	7.4	7.4	0.0
January	7.8	8.6	-0.8	6.5	6.9	-0.4
February	9.7	10.1	-0.4	8.8	9.3	-0.5
March	8.1	8.9	-0.8	6.8	6.7	0.0
All	7.9	8.8	-0.8	7.0	7.4	-0.3

TABLE II. STATISTICAL SUMMARY OF OLD AND NEW FORECASTS (MW ERROR)

	MW Error (Based on 8,132 MW of Wind Capacity)					
	Mean Absolute Error (MW)			*Standard Deviation (MW)*		
Month	***New***	***Old***	***Improve-ment***	***New***	***Old***	***Improve-ment***
October	556	697	-141	514	574	-59
November	539	601	-62	459	512	-53
December	696	741	-45	600	598	2
January	635	699	-65	531	564	-33
February	789	824	-35	718	756	-38
March	661	723	-61	549	548	1
All	645	714	-68	572	599	-26

As shown in Fig. 3, the new forecast was much sharper than the old—reducing the frequency of larger deviations from the actual, thus increasing the overall accuracy of the forecast. The accompanying Table 1 and Table 2 show the improvements in accuracy from a percentage and absolute MW basis using mean absolute error (MAE) and standard deviation as metrics. Table 1 shows that an average sustained improvement of about 0.8% was achieved in the accuracy of the 6-h-ahead forecasts, translating into 68 MW of reduction in average MAE, as shown in Table 2. Although these numbers may seem relatively small, they have an impact on system production costs, as shown below. Further, the reduction in MAE will also result in potential reductions in the amount of operating reserves that need to be carried by the system and the reductions in cost.

Figs. 4 through 7 show the hourly variation of the new and old 6-h forecast errors for three different days to illustrate the significant changes in behavior of the forecast errors. Fig. 4 shows a day in March in which the new forecast was better than the old forecast (lesser magnitude of deviations from actual output) during all hours of the day. Fig. 5 shows a sample day in which the old forecast was more accurate than the new forecast during all hours of the day, and Fig. 6 depicts a sample day in which the old forecast was better than the new during peak hours of the day. Finally, Fig. 7 shows the variations in forecast errors (shown as deviations from actual output) during the week of March 22, 2011, as an illustration of the temporal variations of the forecast errors over the commitment horizon of MAPS.

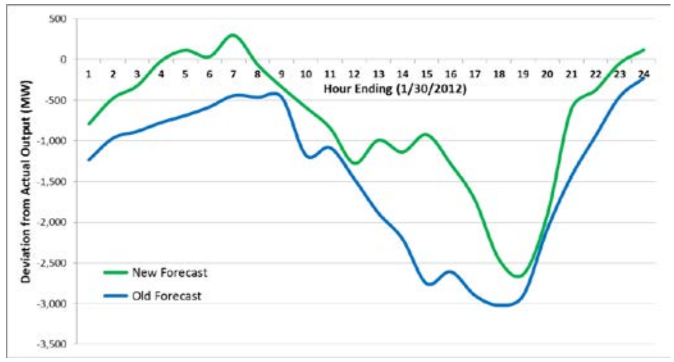

Figure 4. New forecast closer to actual than old forecast.

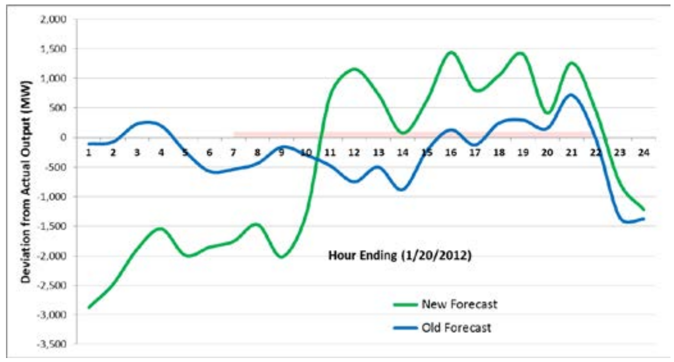

Figure 5. Old forecast closer to actual than new forecast.

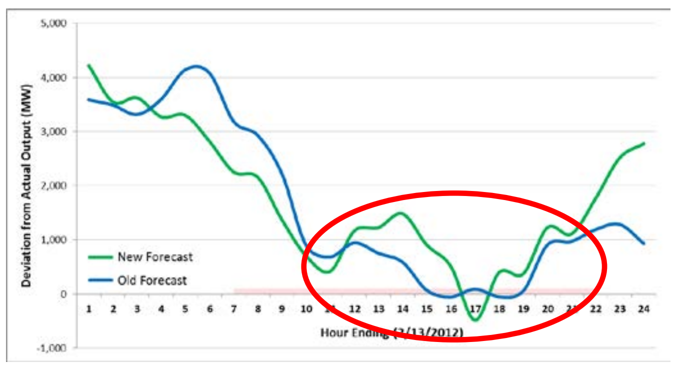

Figure 6. Old forecast closer to actual than new forecast—primarily during peak hours.

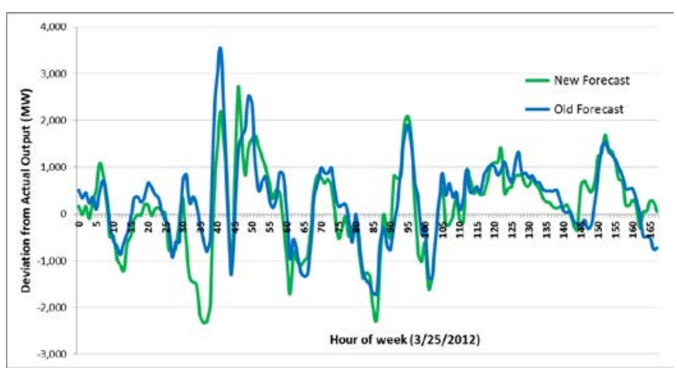

Figure 7. Typical weekly variation in forecast error.

The above figures show that the forecast accuracy improvements varied significantly during a day and during multiple days. There were periods during which the old forecast was better than the new forecast, as shown in Fig. 7 during peak hours. This implies that the corresponding benefits because of improved accuracy of forecasting will also vary, with some hours showing a decrease in system production cost and other hours showing an increase as the impact of change in accuracy of the wind forecasts.

IV. ERCOT Market Simulation Results

This section presents the results of the production simulation analysis to estimate the benefits of short-term forecast accuracy improvement. The simulation was performed for six months from the period of October 2011 to March 2012. The ERCOT power system was calibrated for actual system capacity, including fuel prices, peak load, installed capacity, and generating unit and transmission line outages. The key input assumptions are shown below in Tables III through V.

TABLE III. System Peak Demand (Based on Historical Data) Used in Study

Month	Peak Demand (MW)
October	49,328
November	41,375
December	50,049
January	46,914
February	42,093
March	42,607

TABLE IV. Gas Prices ($/MMBTU) Used in Study (Based on Historical Data)

Year	Month	Houston	South	North	West
2011	October	3.45	3.45	3.42	3.40
2011	November	3.21	3.18	3.14	3.19
2011	December	3.15	3.11	3.09	3.15
2012	January	2.65	2.62	2.61	2.62
2012	February	2.44	2.46	2.45	2.45
2012	March	2.10	2.07	2.09	2.08

TABLE V. Coal Prices ($/MMBTU) Used in Study (Based on Historical Data)

Month	Merchant	Regulated	Average
October	1.91	1.97	1.91
November	1.97	2.07	1.99
December	1.85	1.96	1.88
January	2.67	2.04	2.55
February	1.87	2.01	1.83
March	1.77	1.96	1.68

The impacts on production costs, load payments, wind curtailment, and energy imbalance costs paid by wind generators are shown below in Table VI.

In the total six-month period, there was a measurable sustained reduction in system production cost of approximately $1 million. The decrease in production cost was a direct result from a more efficient unit commitment of resources with start-up times less than 6 h. Also, it can be observed that the total price paid by system loads, as determined by the resulting LMP, decreased significantly because of more efficient operation of conventional units, resulting from improved forecast accuracy. This result is noteworthy because it indicates a reduction in electricity prices that result from improved forecast accuracy. The reduction in wind curtailment is a function of the level of wind penetration and system conditions such as transmission sufficiency. In ERCOT, there is a relatively high penetration of wind; therefore, wind energy is curtailed during hours in which actual wind generation deviates significantly from forecast or because of insufficient transmission or conventional unit minimum up-/down-time constraints. The wind energy curtailed was reduced, as shown in Table VI, because the accuracy of the forecast was higher, resulting in more efficient usage of maximum wind power with given generation and transmission constraints. It can also be noted from Table VI that the benefits in load payments were significantly higher in the January-to-March period compared to the October-to-December period. This was because there were considerably higher wind over-forecast errors in the new forecast than in the old forecast during the month of December, which contributed to increase in energy prices (because the energy expected to come from wind had to be supplied from conventional generation) and, hence, to load payments in December that "netted out" some of the benefits realized during the months of October and November.

The relatively low amount of benefits in system production cost for six months (~ 0.05% of total system production cost) was because of the modest improvement in forecast accuracy (at ~ 1%) and almost directly correlated to natural gas prices because natural gas–burning generators set the price in ERCOT most of the time. To illustrate this point, and to better understand the variation in results to natural gas prices, a sensitivity case was run in which the natural gas prices were doubled (from an average of ~ 2.8 $/MMBtu in the base case to ~ 6 $/MMBtu). Table VII shows the results of this sensitivity.

TABLE VI. Summary of Benefits for Base Case

Parameter	Benefit ($ Savings)		
	Oct.–Dec. 2011	**Jan.–Mar. 2012**	**Total**
Production Cost ($)	833,355	137,706	971,061
Load Payment ($)	3,898,864	28,316,608	32,215,472
Reduction in Wind Curtailment (MWh)	10,407	24,400	34,807
Energy Imbalance Costs Paid by Wind Generators ($)	1,562,626	845,930	2,408,556

TABLE VII. Summary of Benefits for Gas Sensitivity Case

Parameter	Benefit ($ Savings)		
	Oct.–Dec. 2011	**Jan.– Mar. 2012**	**Total**
Production Cost ($)	1,173,509	1,119,428	2,292,937
Load Payment ($)	1,535,411	21,823,012	23,358,423
Reduction in Wind Curtailment (MWh)	17,197	21,103	38,301
Energy Imbalance Costs Paid by Wind Generators ($)	693,983	295,842	989,825

A comparison of Tables VI and VII shows that a doubling in natural gas price doubled the system production cost reductions for the new, more accurate short-term wind forecast. This illustrates the highly dependent nature of benefits on system conditions such as natural gas prices in the case of ERCOT. The comparison between the two cases also revealed that the savings in load payments and the energy imbalance costs actually decreased with increased gas prices. Although there are benefits to improved forecast accuracy and corresponding savings, the doubling of gas prices results in the benefits coming primarily from savings because of energy displacement between lower efficiency and higher efficiency combined-cycle units rather than from energy displacement between coal and natural gas units in the base case, where a smaller gap between coal and gas prices made the fuel switching more economical.

V. Reserve Requirement Reductions

Although the benefits currently shown in the economic evaluation were modest, other benefits are expected to accrue as well. For example, because the forecasts are expected to improve in the 0- to 6-h timeframe, the amount of operating reserves necessary to compensate for wind power forecasting errors is expected to decrease. This study will focus on the non-spinning reserve service requirements (NSRS). The NSRS requirements are currently calculated by ERCOT with direct impact on the net load, and therefore wind power, forecast uncertainty. The calculation assumed in this study follows that of (1).

$$NSRS = \mathrm{Max}\{P^{max} – 500, \mathrm{Min}\{2000, \Phi_{95} – 500 – Regup\}\} \quad (1)$$

where P^{max} is the largest unit in the ERCOT system, Φ_{95} is the 95^{th} percentile of 4-h-ahead net load forecast errors from the previous month, and Regup is the average regulation up-requirement for the period.

This value is calculated for 4-h blocks for each month. The floor of P^{max}—500—is used only for peak hours of 0700 through 2200. The average net load uncertainty will also be calculated for each of these blocks to see if the net load had been on average over-forecasted during those periods. If so, the average over-forecasted value will be added to the NSRS requirement.

Because the 95^{th} percentile value is the main driver for the NSRS requirements, the value may be different than the other benefits seen thus far. This analysis will be part of the final results, where the change in NSRS requirements will be part of the production simulation analysis. This will allow the study team to quantify benefits from efficient commitment of resources as well as those from reduced NSRS requirements to understand the details of benefits coming from improved short-term wind power forecasts.

VI. Conclusion

Preliminary analysis on estimating the economic system-level benefits for improved short-term forecast accuracy on the ERCOT system showed sustained savings in system production cost and load payments, reductions in wind energy curtailed and in energy imbalance payments from wind generators. The analysis was performed for a historical time period of six months, from October 2011 to March 2012. However, the amount of savings in production cost was relatively small when compared to total system production cost. Although this is to be expected for an aggregate average forecast accuracy improvement of approximately 1% MAE combined with low natural gas prices, note that this savings was sustained over the six-month period and is expected to continue into the future. Also, as natural gas prices increase from the historic current lows of around 2 to 3 \$/MMBtu, the benefits will only increase, as shown in the sensitivity case. Future work will include repeating this analysis for one year of improved forecast data as it becomes available. It will be further augmented by considering benefits because of reductions in operating reserves from increased short-term forecast accuracy and exploring the benefit of improved forecast accuracy on system reliability.

Acknowledgments

The authors would like to thank the U.S. Department of Energy and the National Oceanic and Atmospheric Administration for the sponsorship and support of this project.

This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08-GO28308 with the National Renewable Energy Laboratory.

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