National Renewable Energy Laboratory
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Status of Centralized Wind Power Forecasting in North America

May 2009 – May 2010

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Columbia, Maryland

Subcontract Report
NREL/SR-550-47853
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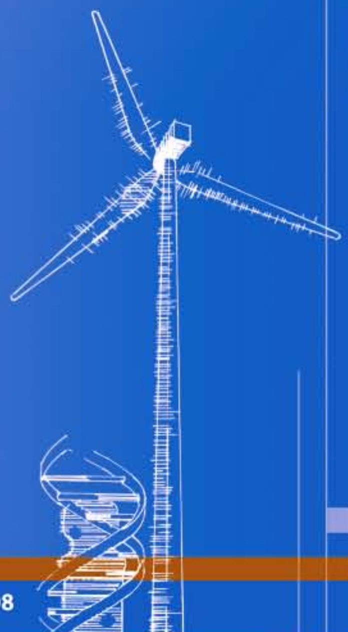

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Introduction

Wind energy development has increased dramatically over the last decade. Nearly 10,000 megawatts (MW) of wind came on-line in the United States in 2009, bringing the total U.S. installed wind capacity to over 35,000 MW (American Wind Energy Association, 2010). This represents nearly a twelve-fold increase in wind capacity since 2000. Installed wind capacity in Canada has more than tripled since 2005, from 684 MW to 2,369 MW as of the end of 2008. According to the North American Electric Reliability Corporation (NERC), another 145 gigawatts (GW) of variable resources (mostly wind) are in various stages of planning (NERC, 2009). While not all of this capacity will come on-line, the amount of variable resource capacity that is under consideration in North America is quite significant.

The rapid growth in installed wind power capacity has led to an increased interest in wind power forecasting. Historically, given its variable nature, wind generation has been taken on an as-available basis, where wind simply "shows up" and grid operators take whatever measures are necessary to accommodate it, mainly reducing the output of other committed generation. At low wind penetrations, such actions are reasonable. At higher levels of wind penetration, however, uncertainty surrounding the amount of wind that can be expected becomes more problematic. In addition, there are costs associated with having excess units online, as well as from reduced unit efficiency and increased O&M. Improved wind forecasting can help reduce these costs. A sample of various wind integration studies estimates that potential annual operating cost savings from using wind forecasting in the day-ahead market range from $20 million to $510 million, depending on the amount of projected wind capacity (see Table 1). A perfect forecast may add $10 million to $60 million more in savings (Piwko, 2009).

Table 1
Projected Impact of Wind Forecasts on Grid Operating Costs

			Projected Annual Operating Cost Savings	
	Peak Load	**Wind Generation**	**State-of-Art Forecast vs. No Forecast**	**Additional Savings from Perfect Forecast vs. State of Art Forecast**
California	64 GW	7.5 GW	$68 M	$19 M
	64 GW	12.5 GW	160 M	38 M
New York	33 GW	3.3 GW	95 M	25 M
Texas	65 GW	5.0 GW	20 M	20 M
	65 GW	10.0 GW	180 M	60 M
	65 GW	15.0 GW	510 M	10 M

Source: Piwko, 2009.

Other organizations have also emphasized the importance of and need for wind power forecasting. NERC stated that "enhanced measurement and forecasting of variable generation output is needed to ensure bulk power system reliability," and that wind forecasting "must be incorporated into real-time operating practices as well as day-to-day operational planning" (NERC, 2009, p. iii). The U.S. Department of Energy (DOE) reported that "the seamless integration of wind plant output forecasting—into both power market operations and utility control room operations—is a critical next step in accommodating large penetrations of wind energy in power systems" (DOE, 2008, p. 86). Wind power forecasting gained further attention when a wind power forecasting system that the Electric Reliability Council of Texas (ERCOT) was testing accurately predicted the large fall-off in wind generation during a well-publicized system event in ERCOT in February 2008 (Ela and Kirby, 2008).

In some markets, wind generators are required to offer a wind power forecast to the power purchaser or to the grid operator. These decentralized wind power forecasts, which are produced either internally or with the assistance of a wind power forecasting company, are not covered in this report. Instead, this report only addresses grid-wide wind power forecasts for all wind generators, which are administered by utilities or regional transmission organizations (RTOs), typically with the assistance of one or more wind power forecasting companies. Such forecasts are known as "central" wind power forecasts. This report focuses on the known central wind power forecasting programs in operation or under development by utilities and grid operators in North America.

Central wind power forecasts offer several advantages over their decentralized counterparts. First, a central wind power forecast will use a consistent wind power forecasting approach and methodology for all wind projects in the region, which will likely lead to more consistent (though not necessarily more accurate) results. Second, the grid operator will have access to wind generation data (and perhaps onsite weather data from all the wind plants) that can be used to improve the performance of centralized wind power forecasting systems, which individual wind plant forecasts may not have access to because of proprietary or confidentiality reasons. Third, a centralized wind power forecasting system may be able to utilize economies of scale, reducing the cost of forecasting per individual wind project as compared to decentralized forecasting systems.

Central wind power forecasts also have some disadvantages. Since they are often based on a single forecasting methodology and provider, the 'more consistent' result may be consistently wrong. They may also be biased for certain weather conditions or events, possibly leading to larger system errors. When a single central wind forecast is in place, competition and the ability to compare alternative results may be reduced or lost. The benefits of a diversity of forecasts and opinions may be significant; some system operators, such as those in Germany, have already implemented ensemble methods (i.e., systems that make use of a variety of methodologies or forecast providers) that use five or more forecasting services.[1] Clearly, system

[1] A study of one such case indicated a day-ahead wind forecast error of 4.2% RMSE using an ensemble wind forecast in Germany (Ernst, 2010, p. 12). However, the California ISO recently found no additional value from using wind power forecasts from multiple providers. The California ISO suggested that this conclusion could be altered if payments to wind power forecasting providers were based on a two-part fee structure, with a small flat rate and a second payment based on the quality of the wind power forecasts (Blatchford and de Mello, 2009, p. 10).

operators will need to weigh the benefits of reduced wind forecast errors versus the cost of having multiple wind forecasting providers (Zavadil, 2009).

Southern California Edison (SCE) was the first utility in North America to adopt central wind power forecasting in late 2000. Similarly, the California Independent System Operator (CAISO) was the first regional transmission organization in North America to adopt central wind power forecasting in 2004. In the case of CAISO, this was the result of negotiations between CAISO and the wind power industry as a quid pro quo for the wind power industry to minimize sizable scheduling deviation penalties in exchange for participating in central wind power forecasting. Since then, Hydro-Québec adopted central wind power forecasting in 2006; followed by the Midwest ISO, the New York ISO (NYISO) and ERCOT in 2008, and PJM in 2009. Xcel Energy, the Alberta Electric System Operator (AESO), and the Ontario Independent Electric System Operator (IESO) all have plans to implement central wind power forecasting in 2010. The Bonneville Power Administration (BPA) is considering whether to implement central wind forecasting as well. Among RTOs, only ISO New England and the Southwest Power Pool have not implemented central wind power forecasting.

This report describes the status of central wind power forecasting in North America, both planned and operating. This report does not discuss the types of wind power forecasting in any depth, as this has been covered elsewhere (Monterio et al., 2009; Zavadil et al., 2009; Grant et al., 2009; Ernst et al., 2007). The report begins with a summary of wind forecasting companies active in currently-operating central wind forecasting systems. The report reviews the individual central wind power forecasting systems in North America, both planned and operating, in more detail. The report then discusses some common characteristics of operating central wind power forecasting systems, reviews some preliminary wind power forecasting performance data, and closes with a summary.

II. Types of Wind Power Forecasts and Wind Power Forecast Performance

There are several types of wind power forecasts. A persistence forecast (i.e., assuming that future values equal the current value) can be reasonably accurate for the next one or two hours, although the accuracy decreases significantly over time. Climatological forecasts (the long-term or average value) may also be used and outperform persistence forecasts looking further out than four to six hours; however, at any time, the actual wind production may be quite different from what is predicted by a climatological forecast.

The wind power forecasting systems discussed in this paper use numerical weather forecast models that monitor and predict weather systems in three dimensions using the physical laws that govern atmospheric motion and represent the known state of the atmosphere. Numerical weather forecast models have limitations in that small atmospheric features cannot be accurately predicted. Numerical weather forecast models also have difficulty predicting large-scale features that evolve over a one-to-two-week period. Therefore, statistical methods are still necessary for very short-term time spans (1-2 hours) and the long-term (>14 days).

Other strategies can be implemented with numerical weather forecast models to improve forecast accuracy, such as using artificial intelligence software to decrease systematic model forecast error or to determine the relationship between wind speed and wind production. Similarly, an ensemble of multiple wind forecasts can reduce wind forecast errors, as the forecast errors from individual wind forecasting models will tend to cancel out (Smith, 2008).

Different wind power forecasts can be used for different time periods. A situational awareness wind forecast is used in real-time for severe weather events. Hour-ahead wind forecasts apply updates to generate forecasts as frequently as 5-minutes for the next four to six hours ahead. Day-ahead wind power forecasts provide hourly forecasts for the next two-to-four days and are typically updated every 6 to 12 hours (Smith, 2009). Additional wind forecasts may be prepared focusing on the potential for wind ramps.

Standard statistical analysis tools are used to evaluate the success of wind forecasting systems in predicting actual wind power generation. The Mean Absolute Error (MAE) takes the simple average of the absolute values of the individual wind forecast errors. Another measure, the Root Mean Square Error (RMSE), involves obtaining the total square error first, then dividing by the total number of individual errors, and then finally taking the square root. RMSE is more sensitive than MAE to outliers, giving a high weight to large errors since they are squared prior to being averaged. The RMSE will always be equal to or greater than the MAE, with a large difference between them signaling a high variance in the individual sample errors (Matsuura and Willmott, 2005; Ontario IESO, 2009d, p. 3-5). Still other means of evaluating wind power forecasts is to compare the performance of the wind power forecast to another forecasting method such as persistence or climatology (Zavadil, 2009).

Table 2 provides some general wind forecast error results. This report will also provide wind forecast error results from nearly all of the RTOs and utilities with wind forecasting, expressed in MAE or RMSE.[2]

Table 2

Average Wind Forecast Error by Time Frame

	Forecast Error	
	Single Plant	**Region**
Hour Ahead		
Energy (% Actual)	10 – 15%	6 – 11%
Capacity (% Rated)	4 – 6%	3 – 6%
Day Ahead		
Hourly Energy (% Actual)	25 – 30%	15 – 18%
Hourly Capacity (% Rated)	10 – 12%	6 – 8%

Source: Smith, 2009.

[2] These can be found in Table 4, and should be analyzed with caution, as discussed in Section VI.

III. Description of Individual Central Wind Forecasting Vendors

There are four central wind forecasting vendors discussed in this paper that are presently providing central wind power forecasting systems in North America – AWS Truewind, Energy & Meteo Systems GmbH, Environment Canada, and WEPROG. AWS Truewind is a forecast vendor that uses its 'eWind®' system to produce forecasts. When producing wind power forecasts for ERCOT, AWS Truewind uses a composite of the individual elements of an ensemble of forecasts for each wind project in the ERCOT territory. The ensemble includes both numerical weather model data and statistical prediction procedures. Currently, AWS Truewind is using statistical modeling for all sites providing valid data; a wind generation resource (WGR) output model with a mixed approach; and three Numerical Weather Prediction (NWP) models, one of which is run every three hours, while the others are run every six hours. AWS Truewind plans to add a nine-NWP model ensemble that will run every six hours; a single NWP model that will run every hour (known as a Rapid Update Cycle); a statistically optimized ensemble procedure that weighs each ensemble member according to its performance in a rolling training sample; and a statistical WGR power output model for all wind generation resources for which the data quality and quantity are adequate (Zack, 2009, p. 13).

When producing forecasts for the NYISO, CAISO, and SCE, AWS Truewind draws on meteorological models, adaptive statistical models, and a forecast delivery system. AWS Truewind also utilizes multi-variate linear regression and neutral network statistical models, as well as atmospheric models. The atmospheric models include a non-hydrostatic model known as the Mesoscale Atmospheric Simulation System, the Weather Research and Forecasting model, and ARPS, a model developed and optimized by the University of Oklahoma to forecast severe convection and rapidly changing atmospheric conditions (AWS Truewind; Kenneth Pennock, pers. comm.).

PJM and the Midwest ISO rely on Energy & Meteo Systems GmbH, a German-based company that uses the Previento forecast model. The Previento model is a physical model that relies upon NWP forecasts (Focken and Lange, 2007, p. 3). These NWP inputs include a combination of numerical weather models weighted according to the weather situation, site-specific power curves based on historical data, and a shortest-term model (0-10 hours) based on power measurements. Wind turbine de-rating data is integrated in the PJM forecast (Ulrich Focken, pers. comm.).

Environment Canada serves as the forecast vendor for Hydro-Québec, and utilizes a GEM 15-km NWP forecast. The wind power forecast uses multiple models, including the Anemos/WPPT model, Hydro-Québec's proprietary models, and forecasting tools installed at and operated by Hydro-Québec. The wind power forecast utilizes statistical models that draw on NWP forecasts, and wind project generation and turbine availability data as inputs. There is also an extensive research and development program on additional and complementary forecasting tools at the Institut de recherché d'Hydro- Québec (IREQ), Hydro-Québec's research institute. Part of this R&D effort includes collaboration with Environment Canada on the development of a high-resolution GEM LAM 2.5-km forecast, the next generation forecasting tool, which is currently under evaluation (Alain Forcione and Jacques Bourret, pers. comm.).

Finally, AESO contracted with the forecast vendor WEPROG in January 2010. WEPROG, which stands for Weather and wind Energy PROGnosis, is a company based in Germany and Denmark that uses a short-range ensemble prediction system based on a multi-scheme approach. The Multi-Scheme Ensemble Prediction System (MSEPS) is an integrated weather forecasting system that uses 75 individual forecasts to replicate weather uncertainty for the next six-days. The difference of WEPROG's 75-member ensemble to a multi-model ensemble using multiple different NWP models is that the ensemble members are based on a single NWP model kernel, where the ensemble members are generated by varying dynamic and physical processes within the NWP model (WEPROG; Corinna Möhrlen, pers. comm.).

IV. RTOs and Utilities with Operating Central Wind Power Forecasting Systems

California ISO

CAISO, which serves 75% of California's load, hit a record peak demand of 50,270 MW on July 24, 2006. CAISO has an available generating capacity of 48,954 MW, which does not include 10,350 MW of net imports. Of CAISO's 2,953 MW of installed wind capacity, 1,005 MW are involved in the ISO's wind forecasting program (CAISO, 2009a; Jim Blatchford, pers. comm.).

CAISO was the first ISO to implement centralized wind power forecasting in North America in June 2004. Its program is known as the Participating Intermittent Resource Program, or PIRP. Intermittent generators that participate pay CAISO a $0.10 per megawatt-hour (MWh) fee; agree to stay in PIRP for one year; install CAISO's telemetry equipment; schedule consistently with the CAISO's forecast of wind generation, and do not make advance energy bids into the California market in order to mitigate concerns that wind generators would try to game the market. The positive and negative imbalances associated with wind power generators are netted out monthly, with any remaining imbalances paid or charged at a monthly weighted Locational Marginal Price (LMP).

AWS Truewind provides the wind power forecasts to the PIRP scheduling coordinator, including:

- Hour-ahead forecasts for each of the next seven hours, by 15 minutes after each hour (hour-ahead is defined as 1 hours and 45 minutes before real time);
- Next day energy forecasts for each hour of the next day, submitted by 5:30 a.m.; and
- Extended hourly capacity forecasts for days two, three, and four, also delivered by 5:30 a.m. on Thursdays and Fridays and selected days before holidays.

CAISO uses the hour-ahead wind power forecast and treats the day-ahead wind power forecast as advisory. CAISO does not currently use a wind ramp forecast, but is working with DOE and BPA to develop a short-term event predictor and a ramp forecast tool (CAISO, 2009c, p. 3; Botterud and Wang, 2009, p. 10; Jim Blatchford, pers. comm.). Though the wind forecasting fee charged to participating intermittent resources is currently \$0.10 per MWh, the wind power forecasting costs have been higher than anticipated, and CAISO covers about \$0.09/MWh from within its operating budget (Ontario IESO, 2009d, p. 8). In addition, CAISO charges an export fee for energy from PIRP facilities exported outside of CAISO. CAISO has proposed to the Federal Energy Regulatory Commission (FERC) that eligible intermittent resources not participating in PIRP also pay the \$0.10 per MWh fee, though this has not yet been approved by FERC.

Wind generators must provide real-time data to CAISO, including wind speed, wind direction, barometric pressure, and ambient temperature. There is a minimum requirement of one meteorological tower, though CAISO plans to require a second meteorology tower; one which could be located in the same location as the first, but at 30 meters below average hub height. CAISO also has applied to FERC to require the reporting of outages of one MW or more if the generator's overall capacity is greater than ten MW (CAISO, 2009b).

CAISO also requires wind generators to supply real-time MW production and MW production revenue metering, as well as locational information for a designated turbine. A designated turbine is the turbine designated to send in anemometry data to represent a surrounding group of turbines. Wind companies must provide this turbine's longitude, latitude, and elevation of its hub height (Blatchford, 2008a, p. 9; Jim Blatchford, pers. comm.).

CAISO recently concluded a year-long wind power forecasting competition among three companies for providing day-ahead and hour-ahead wind power forecasts. Each wind power forecasting provider was responsible for supporting day-ahead and hour-ahead forecasts for four wind projects. AWS Truewind was selected as the winner of the competition and received a new contract to continue wind power forecasting for CAISO. As part of the competition, CAISO conducted a statistical analysis of the wind power forecasts and found the following:

- Aggregate day-ahead wind forecast error was decreased to less than 15% RMSE

- Aggregate hour-ahead wind forecast error was reduced to less than 10% RMSE, which is a 20% improvement over current hour-ahead forecasts used by CAISO for PIRP.

- Geographic diversity and aggregation of wind power forecasts for individual wind projects improved forecasting accuracy in both the day-ahead and hour-ahead time frames. This result suggests poor correlation among the direction of the wind power forecast errors for each wind project, and that the errors may offset each other.

- Wind forecast performance is higher at wind production levels over 80% of installed wind capacity and under 20% of installed wind capacity. This corresponds to a sharp rise in the power curves of wind turbines, and that the amount of energy in wind increases with the curve of wind speed, i.e., 10% increases in wind speed creates a 33% increase in available wind energy (DOE, 2008). Because of that, wind power forecasting is less predictable during the wind projects' mid-range of wind production (Blatchford and de Mello, 2009, p. 9).

Electric Reliability Council of Texas (ERCOT)

ERCOT serves 85% of the load in Texas, representing 75% of Texas geographically. ERCOT's record peak demand reached 63,400 MW in July of 2009. The ISO has an available generating capacity of 80,076 MW, with 8,916 MW of installed wind capacity (ERCOT, 2009; Saathoff, 2009). Total installed wind capacity in Texas is 9,410 MW as of the end of 2009 (American Wind Energy Association, 2010).

ERCOT's centralized wind power forecasting system became operational in July 2008. ERCOT pays for the wind power forecasts and uses them for managing grid operations. An 80% exceedance is applied to the wind power forecast that is used in day-ahead planning, meaning there is an 80% chance that wind production meets or exceeds the forecast (Zack, 2008, p. 18; Botterud and Wang, 2009, p. 10). ERCOT is considering whether to decrease the 80% exceedance in its day-ahead wind power forecast to 50%, as the 80% results in more reserves than are probably needed. Qualified scheduling entities (QSEs) are required to use an ERCOT-provided day-ahead wind forecast as the planned operating level for wind power in their day-ahead resource plan, but QSEs are permitted to provide a lower value if wind capacity will be unavailable or operating at a lower capacity level. QSEs are not required to use the ERCOT day-ahead wind power forecast once ERCOT has completed its capacity studies for the next day (Maggio, 2010a).

The short-term wind power forecast is produced hourly, is delivered fifteen minutes after the hour, covers the next forty-eight hours and represents a 50% exceedance that wind production meets or exceeds the forecast. During the operating day, QSEs may use their own short-term wind power forecast, on the condition that it must outperform ERCOT's wind power forecast. As with the day-ahead wind power forecast, QSEs may provide a lower value if wind capacity is unavailable or operating at a lower capacity level (Maggio, 2010a).

A long-term climatology report, which is not currently required but will be required when the nodal market begins in late 2010, is a facility-by-facility daily wind power forecast, by hour, for the next thirty-six months. The long-term wind power forecasts will be required monthly, and ERCOT is also in the process of developing a large ramp alert forecast (ERCOT, 2008a, p. 4-7; Zack, 2009, p. 16; David Maggio, pers. comm.; Doggett, 2009).

Several data inputs are used for each wind project, including observed generation, the capacity rating and model of each individual turbine, the total number of wind turbines, and the average hub heights and geographic location of the center of the wind project. Additionally, ERCOT requires meteorological data such as wind speed in miles per hour, wind direction in degrees, temperature in degrees Celsius, and barometric pressure measured by millibars. Turbine outage and availability data is currently provided on a voluntary basis, but ERCOT will likely require this data in the future. Observed availability and observed base point for each wind project is required, and intended to be available and used under ERCOT's Nodal Market, however they are not currently available to the wind power forecaster. The base point is the dispatch signal that is sent to the resource based on ERCOT's Security Constrained Economic Dispatch algorithm, and is intended to be used by the wind power forecast vendor to determine if a wind resource is curtailed or not (ERCOT, 2008a, p. 17; ERCOT, 2008b, p. 5; David Maggio, pers. comm.). ERCOT is also developing rules for forecasting potential wind capacity if a wind generator is being curtailed in order to estimate future wind output when ERCOT releases wind generation from curtailment. Such a requirement would allow system operators to have a better sense of future wind output after curtailment and may result in releasing wind generation from curtailment earlier (Maggio, 2010b).

ERCOT also uses the wind power forecast as an input for determining the need for monthly non-spinning reserve service — an ancillary service that ERCOT procures which must be able to reach a specified capacity level within 30 minutes. To determine the monthly requirement for non-spinning reserve service, ERCOT divides the month into four-hour blocks and establishes the monthly requirement to ensure that the combination of regulation up and non-spinning reserve service will cover the 95^{th} percentile of the net load forecast error. Should the net load forecasts be conservative, ERCOT will remove any bias from the net load forecasts and add that value to non-spinning reserve service when determining the monthly requirement (Maggio, 2010a).

Hydro-Québec

Hydro-Québec, which serves the Québec province of Canada, reached a record peak demand of 37,230 MW on January 16, 2009. Hydro-Québec has an available generating capacity of 43,664 MW, with 657 MW of installed wind capacity (Hydro-Québec, 2009; Francis Gosselin, pers. comm.).

The first phase of Hydro-Québec's wind power forecasting system was launched in November 2006, with Environment Canada as the wind power forecast vendor (Balvet et al., 2009). At present, the NWP models are updated twice daily, at midnight and 12 p.m. (UTC), and look forward 48 hours. Hydro-Québec recently augmented their wind power forecasts with additional runs at 6 a.m. and 6 p.m. There is no wind ramp forecast currently. The wind power forecasts are updated hourly, and meteorologists send alarms to grid operators and wind project operators if weather conditions are present that could lead to conditions where wind turbines stop generating because of high wind speeds. These wind power forecasts are paid for by Hydro-Québec (Alain Forcione and Jacques Bourret, pers. comm.).

Hydro-Québec uses the wind power forecasts for day-ahead scheduling (including transaction schedules), reserve requirements, as well as for intra-day rescheduling. Hydro-Québec also sends the wind power forecast to wind project operators for use in short-term maintenance scheduling (Alain Forcione and Jacques Bourret, pers. comm.).

Wind companies must provide Hydro-Québec operational planning data for each wind turbine, including planned turbine availability, the wind turbine power curves, control system information, and information on "cold weather packages" that boost thermal limit capabilities during periods of cold weather (Alain Forcione and Jacques Bourret, pers. comm.). Hydro-Québec also requires real-time data for each wind turbine, including the average, maximum, minimum, and standard deviation of the following: kW of active power; nacelle direction in degrees relative to true North; blade position in degrees; temperature at the nacelle level in degrees Celsius; wind speed in meters per second, which is measured by the nacelle anemometer; and wind direction in degrees, relative to true North, measured by the nacelle wind vane. The wind status of each wind turbine in real-time must also be supplied (Hydro-Québec Distribution, 2009, p. 5).

For each wind project, Hydro-Québec also requires information regarding the wind project layout and facility level real-time data, including the average, minimum, and maximum of the following: the kW of active power, for which the standard deviation is also required; the kW of power available from the substation, the facility, and from individual wind turbines; the number of available wind turbines; and the number of wind turbines not operating because of low or high wind speeds, or low temperatures (Alain Forcione and Jacques Bourret, pers. comm.; Hydro-Québec Distribution, 2009, p. 2). Hydro-Québec also wants the average, minimum, maximum, and standard deviation of a range of data drawn from meteorological towers, including the horizontal and vertical wind speeds in meters per second at each mast anemometer, the wind direction in degrees relative to true North at each weather vane, the temperature in degrees Celsius at each mast anemometer, the percent relative humidity, and the atmospheric pressure in kilopascals (Hydro-Québec Distribution, 2009, p. 3).

Midwest ISO

The Midwest ISO footprint covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, and Ohio. The Midwest ISO has a total available generating capacity of 138,556 MW, and about 7,200 MW of installed wind capacity. On July 31, 2006, the Midwest ISO experienced its record peak demand of 116,030 MW (Midwest ISO, 2009a; Kris Ruud, pers. comm.).

The Midwest ISO began using centralized wind power forecasting in June 2008. The Midwest ISO uses the wind power forecast for next day and multi-day-ahead transmission security planning and outage coordination, as well as next-day and intraday reliability analysis. The Midwest ISO also uses the wind power forecast to project the impact of wind variability on transmission flowgates and to manage transmission constraints (Botterud and Wang, 2009, p. 10; Midwest ISO, 2010).

Energy & Meteo Systems uses three NWP models, each of which is used at four levels. The four levels include commercial pricing (CP) nodes, zones, regions, and the entire Midwest ISO. The CP nodes typically signify a single wind project, while the regions match up geographically with the Midwest ISO's Reliability Regions (East, Central, and West), and the zones represent smaller areas, such as states. In addition, Energy & Meteo Systems also provides a wind power forecast of the MW power output for the optimal combination of all three wind power forecasts, and a statistical power curve for each wind project (Ontario IESO, 2009b, p. 6; Michael McMullen, pers. comm.; Ulrich Focken, pers. comm.).

The Midwest ISO receives forward hourly projections updated from Energy & Meteo Systems providing projected wind power output for each hour over the next seven days. The first six hours are considered the short-term forecast, while the remainder of the wind power forecast period is considered medium- or long-term. Several wind power forecasts indicating possible wind ramps are provided, but the ramp forecasting metrics are still under development (Ulrich Focken, pers. comm.; Michael McMullen, pers. comm.). The Midwest ISO shares its wind forecast with PJM for coordinating transmission security between the two RTOs (Midwest ISO, 2010).

The Midwest ISO pays for the central wind-power forecasting service, and market participants are required to provide the Midwest ISO with non-binding, day-ahead intermittent resource forecasts. These consist of an hourly forecast of projected next-day output and are not currently used for dispatch purposes. For each wind plant, the Midwest ISO provides Energy & Meteo Systems with the latitude and longitude, the hub height, the maximum and historical MW output, and the real-time output. Wind turbine outages are not currently factored into the wind power forecast, but the Midwest ISO anticipates doing so in the future (Ontario IESO, 2009b, p. 6; Midwest ISO, 2009b, p. 2; Michael McMullen, pers. comm.).

New York ISO

The New York ISO (NYISO), which serves the state of New York, reached a record peak demand of 33,939 MW on August 2, 2006. The ISO has a total available generating capacity of 38,190 MW, with an installed wind capacity of 1,275 MW (Edelson, 2009c; NYISO, 2009).

NYISO implemented central wind power forecasting in June 2008, using AWS Truewind's eWind® forecast. NYISO uses wind power forecasts to review day-ahead unit commitment schedules to ensure that there is enough generation committed to meet predicted load and reserve requirements, and to make real-time commitment and dispatch decisions (Botterud and Wang, 2009, p. 10; David Edelson, pers. comm.). In May 2009, NYISO also began using the wind power forecasts to make individual wind plant economic dispatch decisions, also known as economic curtailments (David Edelson, pers. comm.; NYISO Market Issues Working Group, 2007, p. 4).

NYISO receives an updated, day-ahead wind power forecast twice daily – once at 4 a.m., and again at 4 p.m. – that covers the next two operating days. They also receive a real-time wind power forecast that is updated every fifteen minutes and provides fifteen-minute interval data for the next eight hours (Edelson, 2009b, p. 5). The wind power forecasts are blended with persistence forecasts to generate a wind forecast for the next 2½ hours at fifteen-minute intervals. These forecasts are used when making real-time commitments and when scheduling external transactions. Wind power and persistence forecasts for the next hour at five- to fifteen-minute intervals are also used in the real-time dispatch. NYISO may vary the actual blend between persistence and the wind power forecast depending on grid conditions and the wind power forecast. There currently is no wind ramp forecast; however, it is under consideration (Edelson, 2009a, p. 7; David Edelson, pers. comm.).

NYISO assesses a fee to each wind project to pay for central wind power forecasting. The charge, which is subject to change as more wind projects are added, includes a fixed monthly fee of $500 and a separate monthly charge of $7.50 per MW of installed wind capacity (NYISO, 2010). The wind projects are also required to supply data for the wind power forecast, with daily penalties of the greater of $500 or $20/MW if there is a persistent lack of data provided (Federal

Energy Regulatory Commission, p. 4). The required information includes turbine manufacturer specifications, the latitude and longitude coordinates of each turbine, the manufacturer's power curve, plant/turbine availability, and plant or turbine level power output data. On-site meteorological data is also required, including wind speed, wind direction, pressure, temperature, humidity and dew point. NYISO wants data to be taken from multiple heights and from as many points at the wind plant as possible. NYISO prefers that several measurements be taken from a number of stand-alone meteorological towers. While NYISO will accept turbine-mounted sensors for data retrieval, they are not considered ideal because they are impacted by wake effect. Also, while NYISO does not require off-site meteorological towers, it notes that upwind, off-site towers are helpful in predicting large ramp events. Currently, the meteorological data is required from at least one point every 15 minutes, but this requirement will be increased in June 2010 to require data every thirty seconds, and from locations such that no individual turbine is more than 5 km from a reporting sensor (Edelson, 2009b, p. 6-12; David Edelson, pers. comm.).

PJM

The PJM footprint covers all or parts of thirteen states and the District of Columbia, including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The record peak demand for the RTO is 144,644 MW, which was reached on August 2, 2006. PJM has a total available generating capacity of 164,895 MW, with an installed wind capacity of about 2,500 MW (PJM, 2009a; Sanjay Patil, pers. comm.).

PJM launched its centralized wind power forecasting program in April of 2009. Wind power forecasting is done for 28 of the 32 wind projects in PJM; the other four are considered too small to include (Ontario IESO, 2009d, p. 9; PJM, 2009c; PJM, 2009d). PJM pays for the centralized wind power forecast, and uses them in its reliability assessment. The wind power forecast uses a PJM-defined confidence interval, is conducted on five aggregation levels, and includes a statistical power curve for each wind project (Ulrich Focken, pers. comm.).

For the real-time reliability assessment, PJM utilizes a short-term wind power forecast to assess current-day congestion and to ensure that there is enough generation available to account for variability in wind power output. The short-term wind power forecast is updated every ten minutes with a forecast interval of five minutes for the next six hours. For the day-ahead reliability assessment, PJM uses a medium-term wind power forecast, which runs from six hours ahead to 48 hours ahead. The medium-term wind power forecast is used to assess day-ahead congestion and to check that there is enough generation scheduled to supply the forecasted load, transaction schedules, and reserve requirements. In addition to this, PJM also employs a long-term wind power forecast that runs hourly from 48 hours ahead to 168 hours ahead, and is used for forecasting wind power over holidays and weekends. A ramp forecast is also provided, updated every ten minutes in intervals of five minutes for a six-hour time horizon. All wind power forecasts are prepared for individual or aggregate wind projects, as designated by PJM (PJM Power System Coordination Department, 2009, p. 58-60). PJM uses the same wind power forecasting vendor as the Midwest ISO, and both RTOs are exchanging forecasts. Energy & Meteo Systems is also using telemetered data across both RTOs to increase the accuracy of the wind power forecast.

PJM requires certain data and information from wind projects. For each wind turbine, wind generators must provide general information such as the class of the turbine, power generation threshold rates (i.e. minimum and maximum wind speeds), the turbine's capacity, the manufacturer power curves for each individual wind turbine, the longitude and latitude of the wind project site or each turbine, and the hub height of the wind power facility. In addition, wind projects are expected to supply the historic data on measured MW output, outages, and wind speeds at hub height for existing facilities that connect to PJM or bid into the PJM market (PJM Intermittent Resource Working Group, 2009; PJM Power System Coordination Department, 2009, p. 58-59).[3]

PJM also wants data regarding ambient temperature operating limits and information on cold-weather package data. In addition, PJM requires the aggregate reactive capability curve, or 'D-Curve,' and real-time aggregate wind project MW output, telemetered at the low-side net and high-side net of the wind project. The 'low-side net' and 'high-side net' refers to the transformer at the point of interconnection to the grid. Metering is required for both the high-voltage and low-voltage sides (PJM Power System Coordination Department, 2009, p. 58; Ken Schuyler, pers. comm.).

Finally, PJM requires that wind projects install at least one meteorological tower for providing real-time meteorological data, including wind speed in meters per second and wind direction measured in degrees from true north. Alternatively, a wind plant may use wind speed and direction data from select turbines' anemometers and wind vanes. PJM prefers, but does not require, temperature in degrees Fahrenheit and pressure in hectopascals. Percent humidity data is also accepted, though not required (PJM Power System Coordination Department, 2009, p. 58-59).

Southern California Edison

SCE serves a 50,000-square-mile area of California and reached a record peak demand of 23,303 MW on August 31, 2007. SCE considers its available generating capacity data to be confidential, but has reported its 1,073 MW of installed wind capacity (Barry Gilman, pers. comm.; Arthur Canning, pers. comm.). Although SCE is a participating transmission owner in CAISO, SCE has its own central wind forecasting system and does not participate in PIRP.

SCE began using wind power forecasting in November of 2000 and uses AWS Truewind as their wind power forecast vendor. SCE uses the wind power forecasts for scheduling wind energy, and pays for the wind power forecasting service internally. The wind power forecasts are updated twice daily, once at 5 a.m. and again at 5 p.m. Both forecasts look ahead seven days. While no wind ramp forecast is currently prepared, SCE is considering developing such a forecast (Barry Gilman, pers. comm.; Bailey et al., 2001; AWS Truewind).

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[3] 'Outages' refers to any planned, forced, or unplanned outage of turbines of 1 MW or more, or an outage lasting 1 hour or more. Outages related to wind speed, however, will be modeled by the wind power forecasting system, and do not have to be reported (PJM, 2009c).

SCE uses an outside company to collect wind data, which is taken directly off the meters and remotely read. They then make it available to both AWS Truewind and SCE. The data includes MW production metering and meteorological information, including wind speed, direction, temperature, and humidity. SCE uses twelve meteorology towers, with six each in Tehachapi and San Gorgonio. Data on outages and curtailments are incorporated into the wind power forecast system both before wind power production (for forecast correction) and post-production (for calibration of the wind power forecast) (Barry Gilman, pers. comm.).

V. Central Wind Power Forecasting Systems under Development

At least four utilities or regional grid operators have central wind power forecasting programs under development, including Xcel Energy, the Independent Electric System Operator of Ontario (IESO), the Alberta Electric System Operator (AESO), and the Bonneville Power Administration (BPA). These are described in this section.

Alberta Electric System Operator

AESO, which serves the Alberta province of Canada, reached a record peak demand of 9,806 MW in December 2008. AESO has an available generating capacity of about 12,700 MW, with about 560 MW of installed wind capacity (Alberta Electric System Operator; Alberta Electric System Operator, 2009b).

Following completion of a wind forecasting pilot project in 2008, AESO issued a two-year contract in January 2010 with WEPROG to provide a long-term wind power forecast of up to six days and a wind ramping forecast out several hours and updated every 10 minutes. WEPROG is also to provide AESO with visualization tools, uncertainty forecasts, and notifications of any potential system events such as multi-hour wind ramping (Kehler, 2010). The AESO eventually wants to expand hourly wind power forecasting up to 72, 96, or 120 hours ahead, and to have intra-hour forecasts at ten-minute intervals for the next six hours (Alberta Electric System Operator, 2009d, p. 21-28).

AESO plans to begin consulting with industry participants on rules, procedures, standards, technical requirements, communication protocols, and data requirements for central wind power forecasting. AESO also proposes to make near-term and real-time aggregated wind power forecasts available to market participants and to establish a standing work group on wind power forecasting.

All wind generators interconnected with AESO will have to participate in the wind power forecast. AESO has proposed that wind generators pay the costs of central wind power forecasting through a $/MWh charge, escalating the charge by 10% annually, reconciling the differences between wind power forecast costs and revenues from the surcharge annually (Alberta Electric System Operator, 2009a). AESO also has proposed data requirements for wind projects, such as ten-minute meteorology tower and wind generation data, and available capacity. The wind power forecasts will incorporate up to two years of historical meteorological and power data (Frost, 2009).

Bonneville Power Administration

BPA serves an area of 300,000 square miles that includes all of Washington, Oregon, Idaho, western Montana, and small contiguous portions of California, Nevada, Utah, Wyoming and eastern Montana. BPA has a record peak demand of 10,500 MW. It has an available generating capacity of 21,580 MW, with 2,284 MW of installed wind capacity (Bonneville Power Administration, 2009a; Bonneville Power Administration, 2009b, Silverstein, 2009).

Though BPA does not currently have an operational centralized wind-power forecasting system, it is considering whether to prepare its own wind power forecast or to contract out to a third party. A decision is expected in 2010. BPA also installed fourteen meteorology devices in its balancing authority area. Thirteen of these meteorology sites are currently posting data publicly, with the fourteenth under study.[4] Dispatchers and schedulers are expected to be working with wind generation and forecast displays in late 2010. BPA will also be developing a "wind desk" over the next two years to aid dispatchers (Bart McManus and Matthew Neel, pers. comm.; Bonneville Power Administration, 2009c, p. 25).

Independent Electric System Operator of Ontario

The Ontario IESO, which serves the Ontario province in Canada, reached a record peak demand of 27,005 MW on August 1, 2006. It has an available generating capacity of about 35,465 MW, with about 1,200 MW of installed wind capacity (Ontario IESO, 2009c; Ontario IESO, 2009g; Ontario IESO, 2009f).

IESO does not currently have central wind power forecasting. IESO uses a decentralized wind forecasting approach by requiring each wind generator to provide a day-ahead wind power forecast by 11 a.m. Wind generators are required to update their forecasts where actual output is reasonably expected to differ from original forecasts by 2% or 10 MW, whichever is greater. Wind companies comply with this requirement differently, with various companies submitting updates to their forecasts hourly, while other wind companies only submit the day-ahead forecast. The Market Assessment and Compliance Division of IESO, which is charged with enforcement of the market rules, assesses whether generators have exercised due diligence in revising and updating dispatch data/forecasts to reflect changed conditions or expected injections (Ontario IESO, 2009b, 2; Martin Hastings, pers. comm.).

Presently, day-ahead wind power forecasts are used to help assess expected system conditions leading up to real-time. The wind power forecasts are inputted into the run-through of the pre-dispatch every hour, and the results are used to help make decisions regarding day-ahead unit commitment, spare generation on-line actions, and intertie transaction scheduling (Ontario IESO, 2008, p. 2). Real-time power scheduling in Ontario is done on a 5-minute basis. IESO uses 5-minute forecasting in real-time, relying upon a telemetry snapshot of wind output from 10 minutes prior to setting the schedule in real-time.

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[4] Bonneville Power Administration, "Meteorological Information from BPA Weather Sites," http://www.transmission.bpa.gov/Business/Operations/Wind/MetData.aspx.

IESO announced it will convert to central wind power forecasting and will issue an RFP for a wind power forecasting vendor by the end of the second quarter of 2010 (Ontario IESO, 2009f; Deven Huber, pers. comm.). IESO also anticipates issuing new telemetry requirements for wind production data, metrological data and for planned and forced wind plant outages (Rochester, 2010). IESO plans to assign the wind forecasting costs to wind companies, with costs expected to be about $0.135/MWh, in Canadian dollars (about $0.127/MWh in U.S. dollars as of January 2010) (Ontario IESO, 2009a).

Xcel Energy

Though Xcel Energy serves parts of eight states, the information contained in this paper is only applicable for Xcel Energy's operations in Colorado. The record peak demand for this area is 6,884 MW, which was reached in the summer of 2005. It has an available generating capacity of 7,738 MW, with 1,234 MW of installed wind capacity (Public Service Company of Colorado, 2009; Craig Cox, pers. comm.).

Xcel Energy expects to launch centralized wind power forecasting in August 2010. The National Center for Atmospheric Research (NCAR) is working with Xcel to develop the wind power forecast system. NCAR plans to develop a prototype system and run test forecasts during an eighteen month period before transferring the wind power forecasting system over to Xcel; receipt of these 'test' forecasts from NCAR began on September 25, 2009 (University Corporation for Atmospheric Research, 2009; Keith Parks, pers. comm.).

NCAR's wind power forecasting system will use observations of current atmospheric conditions from several sources. Turbine-level and onsite meteorology tower information will be collected from the wind projects into an Xcel Energy scheduling system, and Xcel will also deploy remote sensing technologies for short-term forecasting purposes. The data will then be fed into three NCAR-based tools: the Real-Time Four-Dimensional Data Assimilation System, which constantly renews the simulations with observation updates; the Weather Research and Forecasting computer model, which generates detailed simulations of future atmospheric conditions; and the Dynamic Integrated Forecast System, which statistically optimizes the output based on recent performance. The wind forecasting system involves a 3-kilometer nested forecasting grid, which is updated every three hours (University Corporation for Atmospheric Research, 2009; Parks, 2009, p. 5).

VI. Characteristics of Operating Central Wind Power Forecasting Systems

Centralized wind power forecasting has evolved over time as more utilities and RTOs consider adopting and using forecast data. This section compares and discusses some of the characteristics of central wind power forecasting systems.

Wind Power Forecasting Services: Wind forecasting systems have become more evolved and more complex over time. For instance, the California ISO emphasizes hour-ahead wind power forecasting for the hour-ahead market, and a separate day-ahead wind power forecast is prepared, but is considered advisory. The California ISO also receives extended hourly forecasts for two to four days ahead. In contrast, both the Midwest ISO and PJM, for instance, receive hourly wind forecasts for the next seven days, with PJM's shorter term wind forecasts of 5-minute intervals over the next six hours updated every 10 minutes. The Midwest ISO's wind forecast is prepared at four aggregation levels (commercial pricing nodes, zones, regions, and the entire Midwest ISO footprint) while PJM's covers five aggregation levels.

Who Pays: Two RTOs, the California ISO and NYISO, at least partly recover the wind power forecasting costs directly from wind generators, and AESO and IESO have also proposed charging wind generators for their central wind forecasting programs. Other RTOs and utilities have absorbed the full costs of central wind power forecasting, including PJM, ERCOT, the Midwest ISO, and SCE. Those with central wind power forecasting initiatives under development, other than AESO and IESO, have not announced whether they will assess a fee to wind generators or absorb the costs of central wind power forecasting.[5]

Data Quality and Availability: Data quality and availability has emerged as an important issue in implementing central wind power forecasting. Turbine availability is often assumed at 100% in central wind-power forecasting models, and the reporting of wind turbines being off-line has not always been incorporated in wind power forecast models. Furthermore, the communication links between wind projects and the central wind power forecaster have not always functioned well. The performance of central wind-power forecasting systems has sometimes suffered as a result. Consequently, RTOs and utilities have made data access and quality priorities for launching and maintaining a central wind-power forecasting system. Table 3 shows that wind projects with greater amounts of data available to forecasters have a lower annual MAE for forecasting the next operating hour.

Table 3

Examples from the California ISO on Data Availability and Wind Forecasting Performance

Facility	Data Availability	Next Operating Hour Forecast Annual MAE (% Capacity)	Next Operating Hour Forecast Annual Net Deviation
A1	98.37%	11.30%	-0.18%
A2	87.18%	14.59%	2.18%

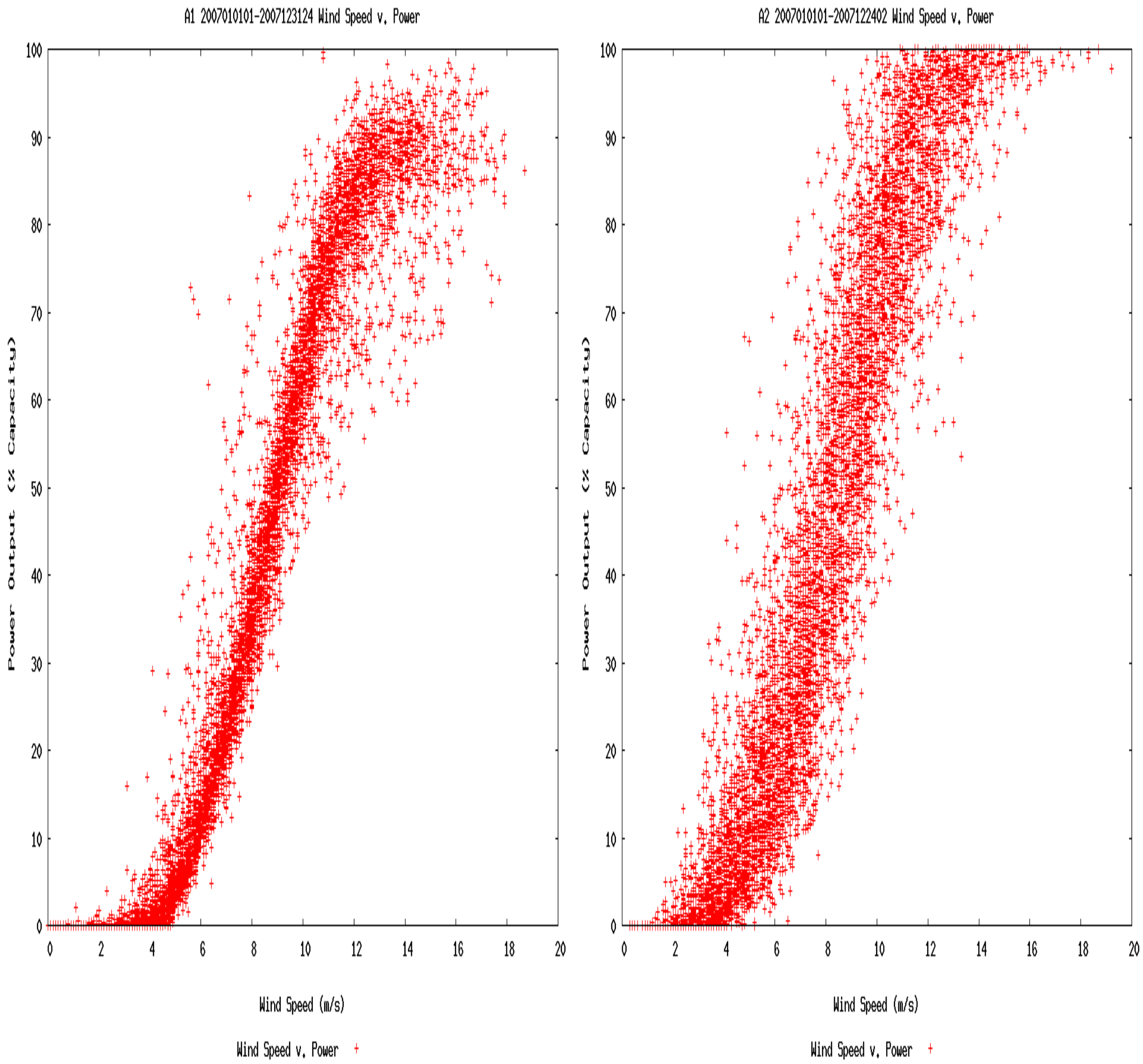
Source: Derived from Blatchford, 2008b, p. 13.

Figure 1 illustrates the forecasted wind speed and power output as compared to a wind turbine power curve. A wind forecast with good data quality and availability will have projected output that tracks close to the manufacturer's power curve, as seen in the figure on the far left. Poorer quality data results in more spread around the power curve, as seen in the figure on the right.

[5] This includes the Bonneville Power Administration and Xcel Energy.

Figure 1

Forecasted Wind Speed vs. Output (an example from the California ISO)



Source: Derived from Blatchford, 2008b, p. 12.

Ramp Forecasts: Few of the operating central wind power forecasting systems include a forecast for ramps from wind generation, although several are considering adding such a forecast. PJM receives an updated wind ramp forecast every ten minutes, covering 5-minute intervals for the next six hours. The Midwest ISO receives wind forecasts that indicate potential wind ramps, but ramp forecasting metrics are still under development. ERCOT, NYISO, and CAISO are all considering incorporating a wind ramp forecast.

How Central Wind Power Forecasts Are Used: The day-ahead markets provide a financial vehicle for market participants to buy and sell energy. In most regions, the day-ahead market uses a security constrained unit commitment (SCUC) that determines the most economic selection of resources to meet bid in load requirements with consideration of the transmission network. Additionally, a second SCUC estimates what additional resources are necessary (if any) over and above what has already been self-committed for bilateral contracts and committed by other markets, such as the day-ahead market and the ancillary services market, to meet the expected real-time demand. This is often referred to as a reliability unit commitment and will usually differ from the day-ahead market in that an ISO provided forecast is used as input.

Centralized wind power forecasting is not generally used to affect day-ahead market schedules. Instead, wind power forecasts are normally used to ensure that enough generation is committed to meet expected load. The Midwest ISO also uses its wind power forecast to conduct week-ahead and intra-day reliability analysis and to determine wind's impact on transmission flowgates. ERCOT uses an 80% exceedance factor (i.e., there is an 80% probability that the projected wind power will exceed a certain level) for the wind power forecast in evaluating whether there are sufficient generating resources for the next day. NYISO uses its wind power forecasts to review day-ahead commitments to ensure there is sufficient generation, but in addition, uses wind power forecasts to assist in real-time commitment and dispatch. Wind power forecasts in the California ISO are used in the hour-ahead market.

When the unit commitment process is centralized, wind integration studies have shown very significant benefits of using a wind power forecast in day-ahead market schedules. If the contributions from wind power are not taken into account when producing the day-ahead market schedule, then conventionally fueled generators may be used inefficiently when wind energy is added to the system in real-time. Indeed, the economic gains reported from use of the wind power forecast are savings to other generators and to retail electric customers (not necessarily the wind generators themselves) due to more efficient dispatch, and saved fuel and lower O&M costs. In addition, if wind power forecasts are used in the centralized reliability unit commitment, it will help identify the additional reserves needed to maintain system reliability, as well as the congestion points that need to be relieved.

The economic and reliability gains from using wind power forecasting can only be realized if wind power forecasts are integrated with day-ahead schedules. Some may contend that this would represent a significant change in procedure for ISOs and RTOs, or a preferential treatment of wind relative to other types of generation. However, similar to the ISO's and RTO's creation of a load forecast today, the ISO's and RTO's creation of a combined "load net wind" forecast could be used after clearing the financial day-ahead market in the reliability commitment process (usually considered the first stage of the next day's real-time market). The ISO and RTO process to commit sufficient resources to supply anticipated load may have to account for the increased uncertainty around the wind power forecast. That said, the "load net wind" forecast should contribute to more efficient market operation and dispatch, improve overall operating reliability, and should not financially benefit wind generators over what they would otherwise receive as price-takers in the real-time market, so this is quite analogous to the use of an improved system load forecast that is created by the ISO or RTO.

Certain system- or market-specific issues may require further study. For example, available forecasts and tools must be investigated to ensure that they are sufficiently accurate for use in security constrained unit commitment. The forecast error may be also be reflected in the day-ahead commitment schedule and prices, and issues around cost responsibility for deviations from the forecast must be considered. Nevertheless, the value of incorporating the wind power forecast into day-ahead scheduling is significant.

Wind Power Forecast Performance: Specific performance data of wind power forecasts is provided in Table 4, though caution should be used in its interpretation. The data in Table 4 encompasses different time periods, making comparisons difficult. Also, many wind power forecasting systems have not been in operation for very long. Added to that, wind power forecast performance may vary significantly (5% or more of the installed capacity of wind) because of location, season, and weather regime. Some weather regimes are also more sensitive to small variations in the start-up conditions of the wind power forecast. Therefore, small differences in current weather conditions can lead to large differences under future weather conditions. In these weather regimes, the performance of wind power forecasting systems is generally not as good as weather regimes with less sensitivity (Zavadil, 2009).

Most importantly, the wind power forecast error numbers in Table 4 cannot be compared with the typical errors for single wind plants because they are aggregated values for the entire system. Geographic distribution of multiple wind plants will reduce the aggregated error rates when compared with the errors from individual wind plants. Comparing the error values from various RTO regions is difficult, however, since each RTO varies in terms of its geographic distribution and penetration of wind plants. Conversely, the wind forecast error statistics provided for Hydro-Québec are for a specific wind project which is located in complex terrain, and should not be compared to the wind forecasting errors that are aggregated values.

Table 4. Wind Forecast Errors for Various Central Wind Power Forecasting Programs[6] (as a percent of installed wind capacity)

	Record Peak Demand	Available Generating Capacity	Installed Wind Capacity	MAE: Time Period	MAE: Forecast Description	MAE	RMSE: Time Period	RMSE: Forecast Description	RMSE
PJM	144,644 MW	164,895 MW	About 2,500 MW	May 2009-July 2009	Monthly for intra-day forecast (0-24hrs-ahead): Monthly for day-ahead forecast (24-48 hrs-ahead): Monthly for evening 4pm forecast (8-32 hrs-ahead):	4.9% - 5.1% 5.9% - 7.9% 5.2% - 5.6%	May 2009 - July 2009	Monthly for intraday forecast (0-24hrs-ahead): Monthly for day-ahead forecast (24-48 hrs-ahead): Monthly for evening 4pm forecast (8-32 hrs-ahead):	6.5% - 7.3% 8.3% – 10.3% 6.9% - 7.6%
ERCOT	62,339 MW	80,076 MW	8,916 MW	May 2009-August 2009	Monthly for 4:30 pm system-wide day-ahead forecast, all-hours	8.28% - 10.73%	N.A.	N.A.	N.A.
Midwest ISO	116,030 MW	138,556 MW	About 7,200 MW	May 2009-July 2009	Monthly for 4:30 pm day-ahead forecast, all-hours	3.3% - 4.5%	Aug 2008 - Aug 2009	Monthly for intraday forecast (0-24hrs-ahead): Monthly for day-ahead forecast (24-48 hrs-ahead)	4% - 7% 5% - 10%
NYISO	33,939 MW	38,190 MW	1,275 MW	June 2008 - March 2009	One hour ahead Day ahead	4.8% 11.5%	N.A.	N.A.	N.A.
CAISO	50,270 MW	48,954 MW[7]	1,005 MW[8]	N.A.	N.A.	N.A.	July 2008 to July 2009	PIRP anticipated accuracy error hour-ahead PIRP anticipated accuracy error day-ahead	<7% RMSE <15% RMSE
Hydro-Québec[9]	37,230 MW	43,664 MW	657 MW	March 15, 2009 – June 1, 2009	1 hr-ahead [10] 4 hrs-ahead 8 hrs-ahead 12 hrs-ahead 24 hrs-ahead	8.5% 13.0% 14.2% 14.4% 15.0%	March 15, 2009 – June 1, 2009	1 hr-ahead 4 hrs-ahead 8 hrs-ahead 12 hrs-ahead 24 hrs-ahead	12.6% 18.0% 19.8% 20.1% 20.7%

6 Although the Ontario IESO does not currently have a central wind forecast, it reported that as of June 2009, the year-to-date MAE system-wide for wind forecasting was 6.7% for the hour-ahead forecast, and 13.6% for the day-ahead. The system-wide RMSE was 8.6% for hour-ahead and 17.9% for day-ahead. Forecast errors for individual wind power projects were slightly higher: MAE ranged between 11% to 17% for the hour-ahead forecast, and 17% to 30% for the day-ahead; RMSE ranged from 16% to 23% for the hour-ahead forecast, and from 17 % to 30% for the day-ahead (Ontario IESO, 2009d, p. 8).

7 Does not include 10,350 MW of net imports.

8 There is a total of 2,953 MW of installed wind capacity in CAISO, of which 1,005 MW is in CAISO's wind forecasting program.

9 Wind forecast error statistics are for a single wind project.

10 By comparison, there was a 7% MAE, and a 10.4% RMSE, one hour ahead pure persistence performance for HQ.

VII. Summary

More and more utilities and RTOs are adopting, or planning to adopt, central wind forecasting systems as a means of more effectively integrating greater amounts of wind power. SCE and the California ISO adopted central wind forecasting in 2000 and 2004, respectively. Hydro-Québec implemented central wind forecasting in 2006 followed by ERCOT, NYISO, and the Midwest ISO in 2008, and PJM in 2009. At least four other entities have plans to implement central wind forecasting in 2010. A majority of the RTOs and utilities absorb the costs of wind forecasting internally, while the California ISO and New York ISO charge wind generators to recover at least part of the wind forecasting costs.

Data quality and availability have emerged as important issues for RTOs and utilities in implementing central wind forecasting systems, though several difficulties have surfaced in data transfer and communication. Information such as turbine availability and whether wind plants were curtailed or not was not always made available to wind forecasters, affecting wind forecast accuracy. As a result, RTOs and utilities are increasingly imposing data requirements on wind generators. The New York ISO has taken the additional step of imposing penalties for failure to provide data.

Day-ahead wind forecasts are being used in reliability planning, but not directly in day-ahead market decisions, despite results from several wind integration studies that suggest significant savings from reduced fuel and O&M costs if wind forecasts were used as part of day-ahead unit commitment schedules. Some of this may reflect the fact that wind forecasting is still in the early stages of implementation. Ultimately, the RTO could create and use a "load net wind" forecast to clear the day-ahead market (albeit with some additional consideration for the increased uncertainty around the forecast), which could contribute to more efficient market operation and dispatch.

Wind forecasting is widely seen as a pre-requisite for integrating larger amounts of wind power, in minimizing operating impacts of wind power, and providing critical information to system operators to help maintain grid reliability. Wind forecasting is also seen as an important tool for minimizing the costs of integrating more wind power. Therefore, more utilities and RTOs will likely adopt central wind power forecasting in North America in the near future. Continuing research and experimentation may also lead to increases in wind power forecasting accuracy, also seen as an important step towards successfully managing the power grid with large amounts of wind power.

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This report addresses and surveys grid-wide wind power forecasts for all wind generators, which are administered by utilities or regional transmission organizations (RTOs), typically with the assistance of one or more wind power forecasting companies.

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