INTEGRATING WIND ENERGY WITH THE BPA POWER SYSTEM: PRELIMINARY STUDY

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Disclaimer

This paper is a preliminary study concerning the integration of wind energy into the BPA system. It is based on four months of BPA wind and area load data. This study is not a comprehensive study, and further analysis is needed to more definitively estimate the potential impacts of large amounts of wind energy on the BPA system. The analysis and conclusions contained in this study are the author's and do not necessarily represent the views of BPA. This study is preliminary and is based on data and information derived from a four month period. Only recently have commercial scale wind projects been integrated with the existing BPA system. Consequently, further analysis will be needed to assess the full impact of large scale wind integration on the BPA hydro/thermal and transmission system.

CONTENTS

SUMMARY

As the amount of wind capacity installed in the Pacific Northwest increases, so too does the need to carefully analyze and quantify its effects on bulk-power planning and operations. These effects are both physical (MW of capacity reassigned from one function to another) and financial (generating-unit operating costs and wholesale-market opportunity costs).

Integrating wind output into a large power system is challenging because of wind’s unique characteristics. Relative to other electricity-production technologies, wind output is uncertain, uncontrollable, and variable.

This study focuses on the time between day-ahead operational planning (e.g., production of a system load forecast and preparation of hourly schedules for generating-unit operation) and real-time operations (i.e., the minute-to-minute movements of certain generating units to maintain the necessary generation:load balance). Specifically, this study examined day-ahead forecasting errors for the Bonneville Power Administration (BPA) system load and wind output plus the real-time requirements for the regulation and load-following (intrahour balancing) ancillary services.

This study uses data on the electric-energy outputs from wind farms as well as data from the BPA hydroelectric system to address these wind-integration issues. These data cover the first four months of 2002. They include 1-minute energy outputs from four wind farms in Washington and Oregon (with a total capacity of 164 MW), BPA’s day-ahead hourly system-load forecast and forecast errors, BPA control-area load at the 1- and 5-minute levels (to analyze regulation and load following requirements, respectively), and the amount of generating capacity available each hour but not needed for energy or ancillary services.

Because wind output is largely uncorrelated with BPA load, the effects of wind on the BPA power system are small. In addition, the effects of wind are roughly symmetrical, sometimes “consuming” capacity and at other times “producing” capacity. For example, 1000 MW of wind capacity might require or provide about 100 MW of capacity to the BPA system. Therefore, it is difficult to unambiguously determine how much, if any, generating capacity BPA should set aside day ahead to accommodate wind output.

Fig. S-1 shows the effects on BPA’s real-time capacity requirements of errors in its day-ahead load forecast and the combined effects of this load-forecast error and 1000 MW of wind capacity (i.e., the day-ahead error in the forecast of wind output and the real-time requirements for regulation and intrahour balancing). The effects of wind are generally small, occasionally large, and roughly symmetrical.

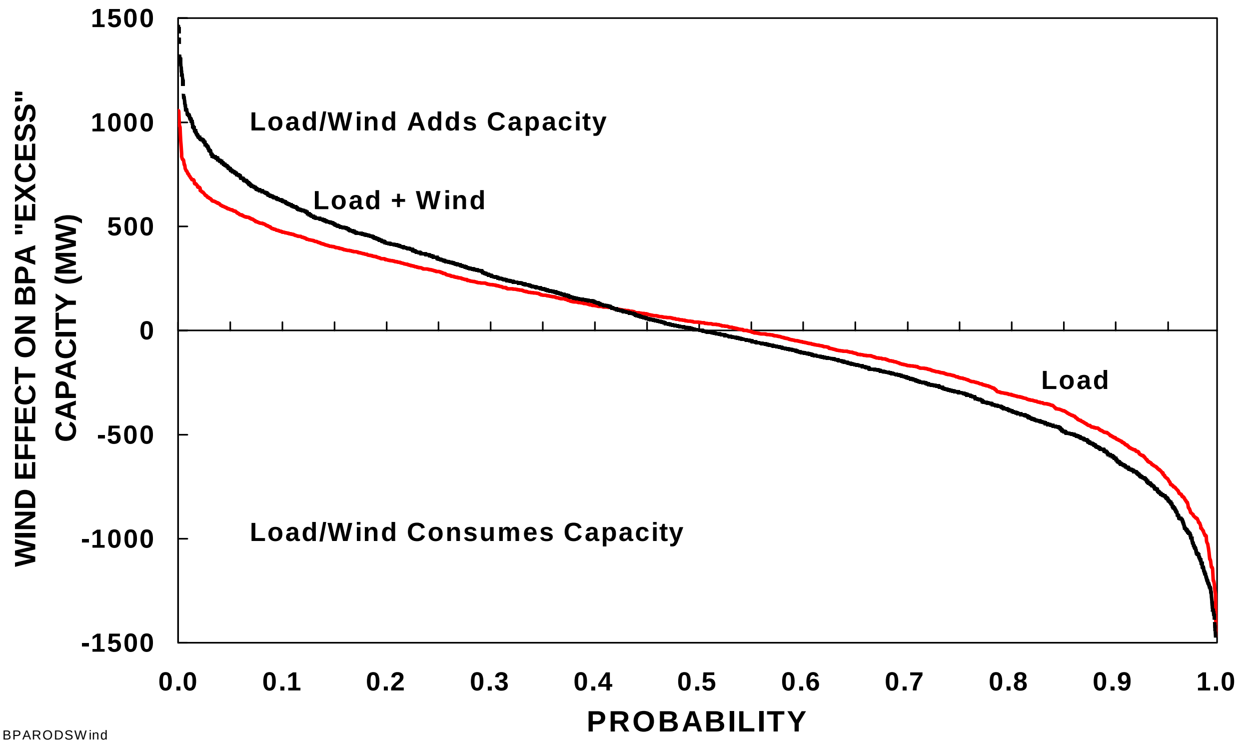

Fig. S-1. Probability distribution of the effects of errors in day-ahead forecasts of BPA system load and 1000 MW of wind capacity.

Although the physical requirements for wind integration appear, based on this initial analysis, to be small, BPA should consider additional research in this area. BPA might repeat the present analysis with additional data as they become available (e.g., with a full year of data). Also, BPA should use its new optimization model (Columbia Vista) to quantify the physical and economic effects of day-ahead uncertainties (not just in wind, but in loads, customer contracts, and other factors) on operations, power purchase and sale opportunities, and costs.

LIST OF ACRONYMS

ACE	Area control error
AGC	Automatic generation control
BPA	Bonneville Power Administration
CPS	Control Performance Standard
DA	Day ahead
FERC	U.S. Federal Energy Regulatory Commission
ISO	Independent system operator
NERC	North American Electric Reliability Council
PJM	Pennsylvania-New Jersey-Maryland Interconnection, LLC
PBL	Power Business Line
RT	Real time
RTO	Regional transmission organization
SMD	Standard market design
TBL	Transmission Business Line

BACKGROUND

Probably no major electric utility in the United States generates as large a share of its energy from hydroelectric resources as does the Bonneville Power Administration (BPA). BPA may soon become one of the largest U.S. buyers of wind power as well.

Hydro and wind power share several similarities and also some stark differences. Both are renewable resources. Converting wind and water into electricity produces no harmful air pollutants. And both resources depend on nature: when, where, and how hard it rains and snows for hydro and when, where, and how hard the wind blows for wind energy.

On the other hand, the two resources are quite different, especially for short-term (day-ahead, DA) planning and real-time (RT) operations. Hydro resources are very fast and flexible compared to typical steam-powered thermal plants. For example, coal plants can ramp up and down (in MW/minute) at 1 to 2% per minute, whereas hydro units can typically ramp 5 to 20 times as fast. The startup times and costs for hydro units are also small compared with those for thermal plants.

The electrical output from wind farms, however, is characterized by its relative unpredictability, lack of control, and variability (Hirst 2001b; Milligan et al. 2002). These three characteristics complicate integration of wind energy with a typical bulk-power system. Because electricity cannot be readily stored, power-system operators must balance generation to load on a near-real-time basis. In addition, the essentially passive nature of transmission systems requires system operators to use dispatchable generating units to keep transmission elements within their thermal, voltage, and stability limits. Because of wind's variability, unpredictability, and lack of control, wind resources cannot be used to help maintain RT reliability (called security) on the electrical grid. On the contrary, wind imposes costs on the grid because system operators must deploy other, flexible resources to offset the effects of wind.

This study discusses the physical (and, to a lesser extent, financial) costs that wind imposes on the BPA bulk-power system. The focus is on the period between day ahead (when units are committed for the following day) and real time (when units are dispatched up or down to meet the two sets of constraints noted above). This study addresses three sets of costs: those associated with the commitment (or decommitment) of capacity to address errors in the day-ahead forecast of hourly wind output, real-time regulation, and real-time load following. The study does not deal with transmission, the costs associated with transmission access, congestion, or losses.

This study is timely for several reasons. First, the amount of wind capacity in the Pacific Northwest is growing rapidly. As of mid-2001, BPA had received proposals for more than 2500 MW of wind (BPA 2001). As of mid-2002, BPA's Power Business Line (PBL) had 198 MW of wind under contract and another 580 MW under consideration. BPA's Transmission Business Line (TBL) has received requests for interconnection of about 5000 MW of wind capacity in Oregon and Washington (Darr 2002).

Second, until recently, data on the output (on a minute-by-minute basis) from wind farms was not available. As a consequence, the charges for wind integration lacked a solid foundation of data and analysis. These charges were typically based on simple assumptions and rules of thumb. For example, the pro forma tariff in the Federal Energy Regulatory Commission's (FERC 1996) Order 888 included an energy-imbalance service. The charge for undergeneration could be $100/MWh, regardless of the actual cost to the utility control area to offset this undergeneration. And Order 888 permitted the utility to take any overgeneration without any payment. While such penalties might be reasonable for energy resources that can be controlled to follow a schedule, they are punitive for intermittent resources, such as wind.

Third, the electricity industry is rapidly changing, from a world dominated by engineering decisions and administrative rules to one in which market forces (primarily prices) encourage market participants to act in ways that benefit the electrical system. For example, the Pennsylvania-New Jersey-Maryland Interconnection [PJM, a large independent system operator (ISO) in the Mid-Atlantic region] operates a RT balancing market in which prices are set every five minutes. These prices are based on the bids of the marginal generators running during each interval. Resources that overgenerate relative to their schedule receive the market-clearing price for the excess generation. Resources that undergenerate pay the market-clearing price for their deficiency. PJM, in contrast to the energy-imbalance schedule in Order 888, imposes no penalties on generators or loads that produce or consume at levels different from their schedules. Such a market-based system is much more hospitable—and, more important, fair—to intermittent resources.

In recognition of the success of the PJM (and New York) ISO markets, FERC (2002a and b) is developing a standard market design (SMD), with a notice of proposed rulemaking issued in July 2002 and a final rule planned for the end of 2002. This rule will include DA and RT markets for energy, ancillary services, and transmission congestion. One of the FERC principles for SMD is that "… intermittent supply resources should be able to participate fully in energy, ancillary services and capacity markets."

In light of these and other factors, BPA may develop an analytical method and standard data requirements (from both the wind farm and the TBL system operator) to determine the costs of wind integration. This study represents an important step in this development, dealing with the balancing and integration requirements from day ahead (e.g., noon on the day before the operating day) through real time. This integration encompasses the following activities:

- DA unit commitment: Most utilities and ISOs make decisions on which units to turn on and when to do so about 12 hours before the start of the operating day. In today's ISOs [and tomorrow's regional transmission organizations (RTOs)], these decisions are based on generator offers and demand bids provided to the system operator. The ability of a wind farm to bid into such DA markets will depend strongly on the accuracy of the wind forecast used by the wind-farm manager.

- Intrahour balancing: In real time, the system operator dispatches resources participating in its intrahour energy market to maintain the necessary balance between generation and load (discussed in Chapter 6). Once every 5 to 15 minutes, the system operator runs an economic-dispatch model to move generators up or down to follow changes in load and unscheduled generator outputs at the lowest possible operating cost. Generators that participate in the system operator's balancing market provide the load-following ancillary service.

- Regulation: To track changes in the minute-to-minute balance between generation and load, the system operator uses its automatic-generation-control (AGC) system to dispatch those generators providing the regulation ancillary service. These generators respond to short-term generation:load imbalances that are not addressed by the economic-dispatch process.

The remainder of this study is organized as follows. Chapter 2 reviews briefly BPA's operation of its hydroelectric system. Chapter 3 describes the data resources used in this study. Chapter 4 summarizes output data for four wind farms with a total capacity of 164 MW, for the 4-month period from January through April 2002. Chapter 5 compares DA forecast errors for BPA system load and wind output for the same period. Chapter 6 discusses the intrahour load-following (energy-imbalance) and regulation requirements for wind and the BPA load. Chapter 7 combines the results of Chapters 5 and 6 with data on the "excess" capacity BPA has available each hour to show how much of this capacity is "consumed" by wind. The final chapter summarizes the results of this study and suggests additional work on wind integration.

OPERATION OF THE BPA HYDROELECTRIC SYSTEM

My initial plan had been to determine how BPA manages its system today and the cost and price implications of these operating decisions. I had envisioned a study in which detailed information on current operations and their cost and price implications (top half of Fig. 1) would provide a baseline against which to compare cases in which the output from wind farms is introduced into the power system (bottom half of Fig. 1). The difference between the with- and without-wind cases (right hand side of the figure) would show the costs to integrate various amounts of wind capacity with the BPA electrical system.

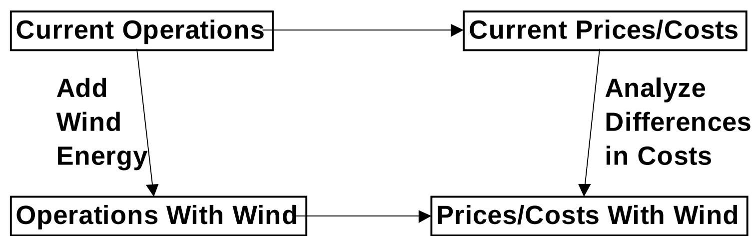

Fig. 1. Schematic of original plan to analyze the costs of integrating wind resources with the BPA power system.

I had assumed that, like nonhydro utilities and ISOs in other parts of North America, BPA would use mathematical optimization models to schedule its generating units day ahead (unit commitment) to meet expected changes in loads and interchange schedules on an hour-to-hour basis. In addition, I had assumed that BPA would use an economic dispatch model to move generators once every 5 or 10 minutes to ensure that electricity is produced at the lowest possible operating cost.

In reality, BPA operates the Federal hydro system from an engineering perspective, rather than an economic perspective. That is, the computer models BPA uses to guide decisions on hourly, daily, and longer-term reservoir and project (dam)* operations focus on engineering characteristics rather than cost or market-price considerations. Perhaps more important, electricity is only one of many products and services provided by the river. Its production is constrained by these other factors, including flood control, navigation, recreation, irrigation, and, especially, fish protection. The BPA models indicate how much water can/should move

*Most of the BPA decisions on hydroelectric operations are made at the project level. Decisions on which units to operate at what level are made by the Corps of Engineers and the Bureau of Reclamation operators at each dam. It is not clear whether unit operations seek to minimize operating costs, maximize efficiency of converting water to electricity, or meet some other objective. The only exception to this rule is if TBL, the BPA control-area operator, needs additional spinning reserve, in which case its system operator will ask the dam operators to turn on additional units.

through each project to meet the various constraints imposed on the system, conditional on the amounts and timing of releases from upstream dams and tributary flows. These water flows are then converted into power production, with any surplus or deficit made up by either adjustments of operations at Grand Coulee or by short-term power sales or purchases. In general, BPA market decisions (i.e., whether to buy or sell power) are based more on hydro constraints than on market conditions (wholesale electricity prices). BPA relies primarily on the judgments of its schedulers and traders, rather than mathematical models, in deciding how to operate individual projects and whether and when to buy or sell power on the wholesale market.

Further complicating assessment of the costs of wind integration is the absence of explicit wholesale markets for energy, especially ones that operate at an hourly level, either day ahead, hour ahead, or in real time. The primary indicator of wholesale power prices in the Pacific Northwest is the Dow Jones index, which provides estimates of onpeak (16 hours) and offpeak prices (8 hours) for the following day. No markets or proxies exist for the prices of ancillary services in the Northwest.

Finally, TBL performs all of its balancing functions using hydroelectric generators that are on AGC. In other words, the units that are normally thought of as providing the regulation ancillary service provide regulation and load following (i.e., intrahour balancing) as well as adjustments for the hour-to-hour interchange schedule changes and for load-forecast errors. Compared with the fossil-fired generators used by most control-area operators to balance generation to load, hydro units are very fast, flexible, and inexpensive to ramp up and down.

Fortunately, BPA is in the process of enhancing its analytical capabilities in important ways. It is building a new computer model, called Columbia Vista, that features optimization (i.e., cost minimization) of the hydroelectric system (Acres Productive Technologies 2001 and 2002). Based on various user inputs (e.g., expected market prices for energy and ancillary services, limits on power sales and purchases, transmission limits, streamflow forecasts, firm-load requirements, and hydraulic constraints), Columbia Vista will establish an hourly schedule (e.g., day ahead) for the BPA hydro resources to maximize its operating earnings from the production, sale, and purchase of electricity.

Because of these current limitations in BPA's hydroelectric modeling capability and the lack of performance data on wind farms in the Pacific Northwest, prior BPA efforts to estimate the costs of wind integration have been ad hoc. For example, one analysis of wind pricing calculated a cost to wind of about \$2/MWh for the regulation service. By comparison, the market costs of regulation in the PJM and New York ISOs averaged \$0.5/MWh and \$0.2/MWh, respectively, for 2001. Why, given the BPA hydro resources, should regulation cost four to ten times as much as it does in areas where regulation is provided primarily by more expensive fossil units?

DATA RESOURCES

I used several data sets provided by staff in PBL and TBL. With one exception (discussed below), the data covered the 4-month period from January through April 2002. PBL sent me 2-second data on the wind output (in kW) from four wind farms: Vansycle (25 MW), Stateline (90 MW), Condon (25 MW), and Klondike (24 MW), with a total capacity of 164 MW (Fig. 2). For the present analytical purposes, I aggregated the 2-second data to the 1-, 5-, and 60-minute levels. PBL also provided hourly data on the output from a 15-MW wind farm in southeastern Wyoming, used to analyze the benefits of geographical dispersion in Chapter 4.

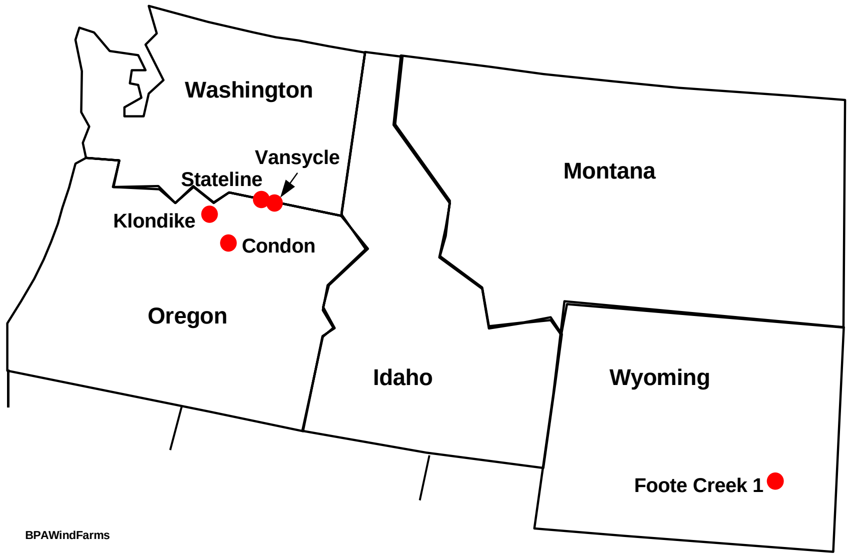

Fig. 2. Map of the Pacific Northwest showing the approximate locations of the wind farms analyzed here.

PBL sent me data on hourly loads for the BPA system as well as the DA load forecasts for each hour.

TBL provided three sets of data. The first was BPA control-area load* at the 5-minute level and the second was hourly data on the amounts of capacity required for contingency reserves and regulation and the amounts of capacity available for these functions. The third data set included 2-second data on the BPA control-area load for the last 13 days of June 2002.#

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*The BPA *system* load is the responsibility of PBL and can include loads outside the BPA control area. The BPA *control-area* load is the responsibility of TBL and refers to the loads that are within the electrical boundaries of the control area.

#It would have required considerable effort for TBL staff to retrieve these short-interval load data for the January-to-April period. However, they could easily provide these data on a going-forward basis, which is why the analysis of regulation in Chapter 6 covers a different time period than the other analyses.

In organizing the data, I did very little data-quality management. My philosophy was to leave the data intact unless I was confident that a particular number was wrong. Wind data were missing for 0 hours in January, 39 hours in February, 2 hours in March, and 10 hours in April. In addition, BPA did not provide wind output data for the last four days of April (April 27 through 31). Some of the wind data showed small negative amounts, which I assumed referred to parasitic consumption at the wind site. At the other end of the spectrum, some of the data for the Klondike wind farm showed outputs as high as 110% of capacity. In all cases, I retained these values, which likely leads to an overestimate of wind-output variability.

Some of the 5-minute values for BPA load were completely inconsistent with the adjacent values; I adjusted these values to better fit with the adjoining values. I "corrected" the DA load forecasts for eight hours on April 15, a period during which the original load forecasts were off by several thousand megawatts. Enough 2-second wind and load data were missing that I had to drop about 5% of the hours for the June 2002 analysis of regulation requirements.

WIND CHARACTERISTICS

As expected, the wind output shows substantial variability, from minute to minute, hour to hour, day to day, and week to week (compare the top and bottom portions of Fig. 3). For the four months analyzed here, the capacity factor, averaged over the 164 MW at the four sites, was 32%.[*]

Because the four sites are close to each other (about 150 miles from Klondike to Vansycle; Fig. 2), the hourly wind output is highly correlated among them (Fig. 4). Although the four sets of outputs are correlated, the existence of multiple sites reduces overall variability. Figure 5, the top part of which shows the standard deviations of the aggregate hourly wind output for each month, illustrates this phenomenon. The triangles (top of each line) are the standard deviations that would have occurred if the outputs of the wind farms were perfectly correlated (i.e., if they were colocated).[#] The squares are the actual standard deviations. And the circles at the bottom of each line are the values that would occur if the outputs of the wind farms were completely *un*correlated.[§] Because the squares are closer to the top of each line than to the bottom, I conclude that the outputs are more correlated than uncorrelated. These observations suggest that if wind farms are geographically dispersed, the variability of the total output will be reduced. Such a reduction in hourly variability would likely reduce the costs of wind integration.

To test this hypothesis on geographical dispersion, BPA provided hourly data on a 15-MW wind farm in Wyoming (Foote Creek #1), located almost 1000 miles from the four other sites. The correlation coefficient between the hourly output at the four wind farms analyzed here and the Wyoming farm was only 0.18, far below the average of the correlation coefficients (0.56) among the four original sites. As shown in the bottom of Fig. 5, this lack of correlation substantially reduces the standard deviation of the combination of wind farms. In

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[*]On a month by month basis, the capacity factors were 33% in January, 22% in February, 38% in March, and 32% in April. For this 4-month period, the capacity factors varied across the four sites: 42% at VanSycle, 31% at Stateline, 20% at Condon, and 33% at Klondike.

[#]The standard deviation of the total (T) for i variables that are completely correlated with each other is the sum of the standard deviations of the individual components ($\sigma_T = \sum \sigma_i$).

[§]The standard deviation of the total for i variables that are completely uncorrelated with each other is the square root of the sum of the squares of the individual components [$\sigma_T = \sqrt{\sum (\sigma_i)^2}$].

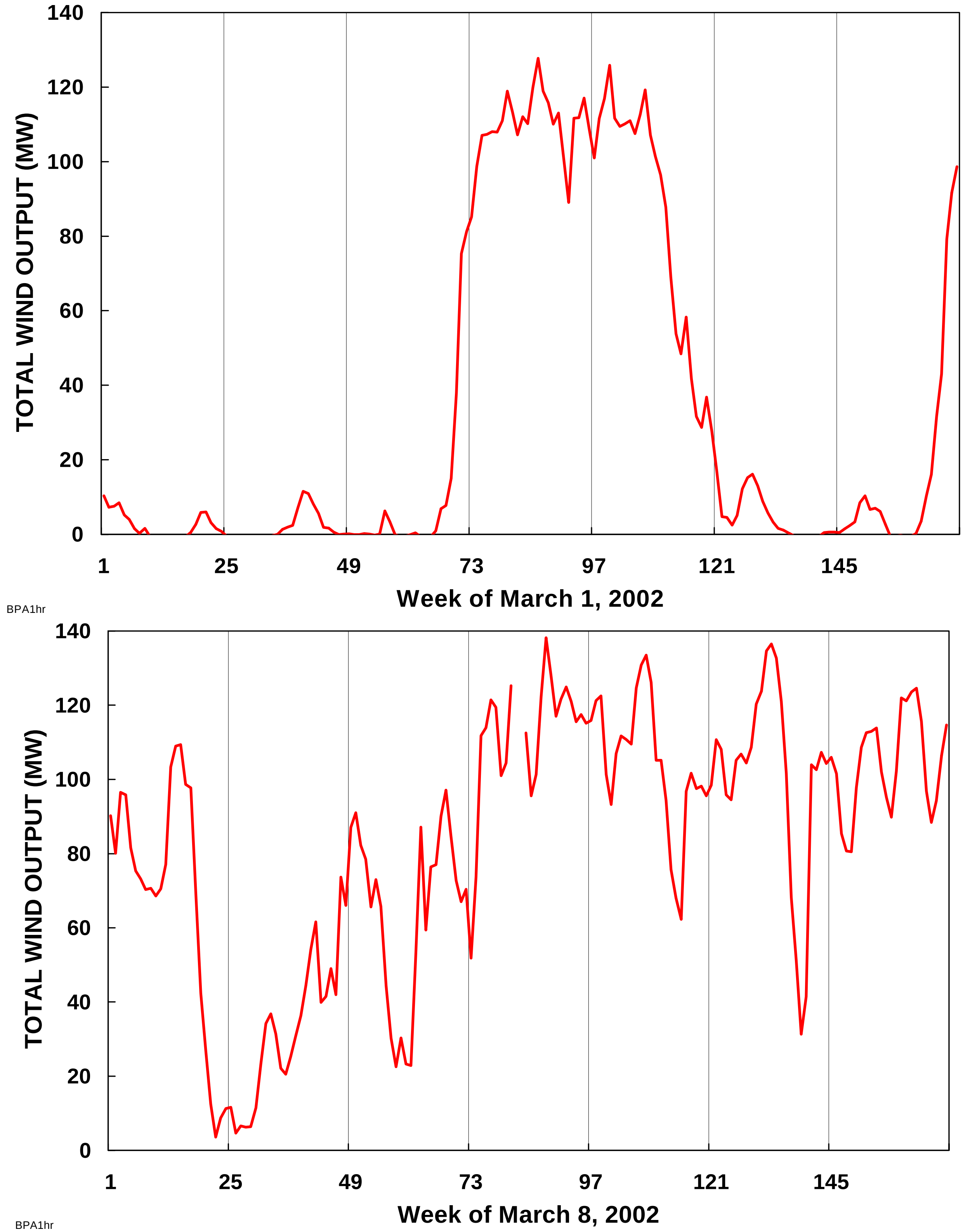


Fig. 3. **Aggregate hourly output for the first (top) and second (bottom) weeks in March 2002. Wind-output data were missing for two hours on March 11.**

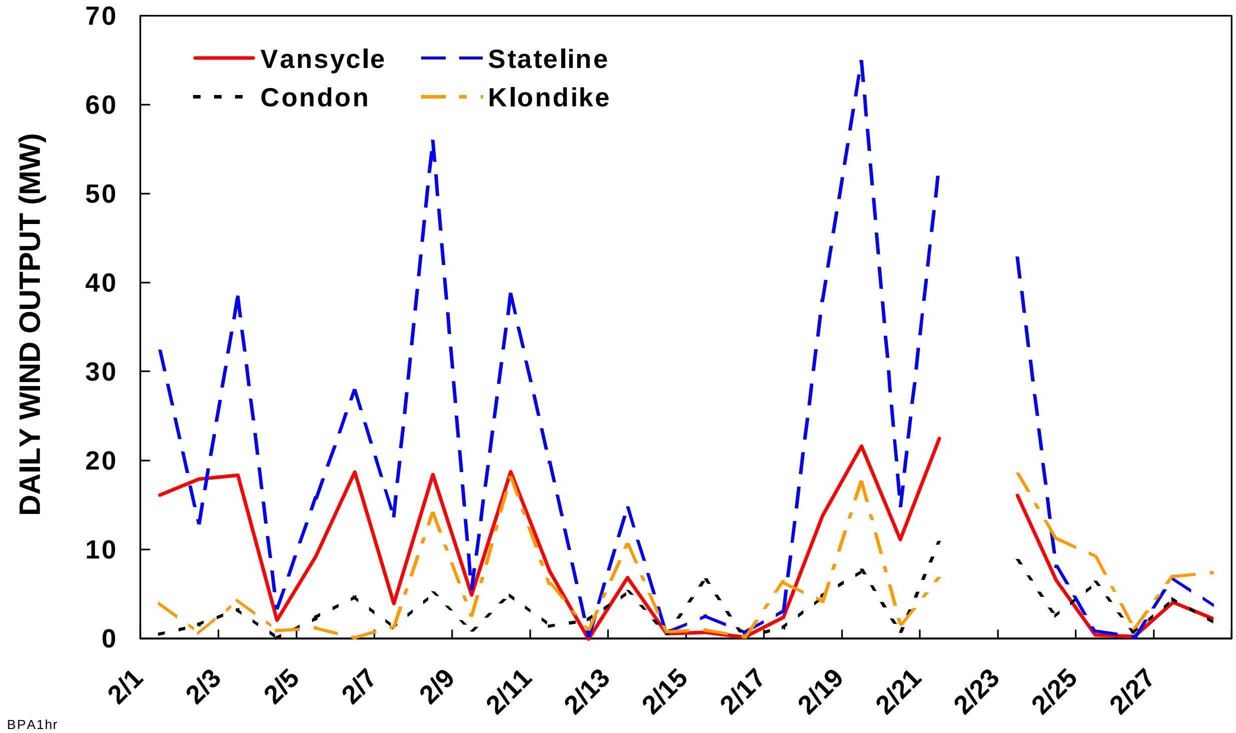


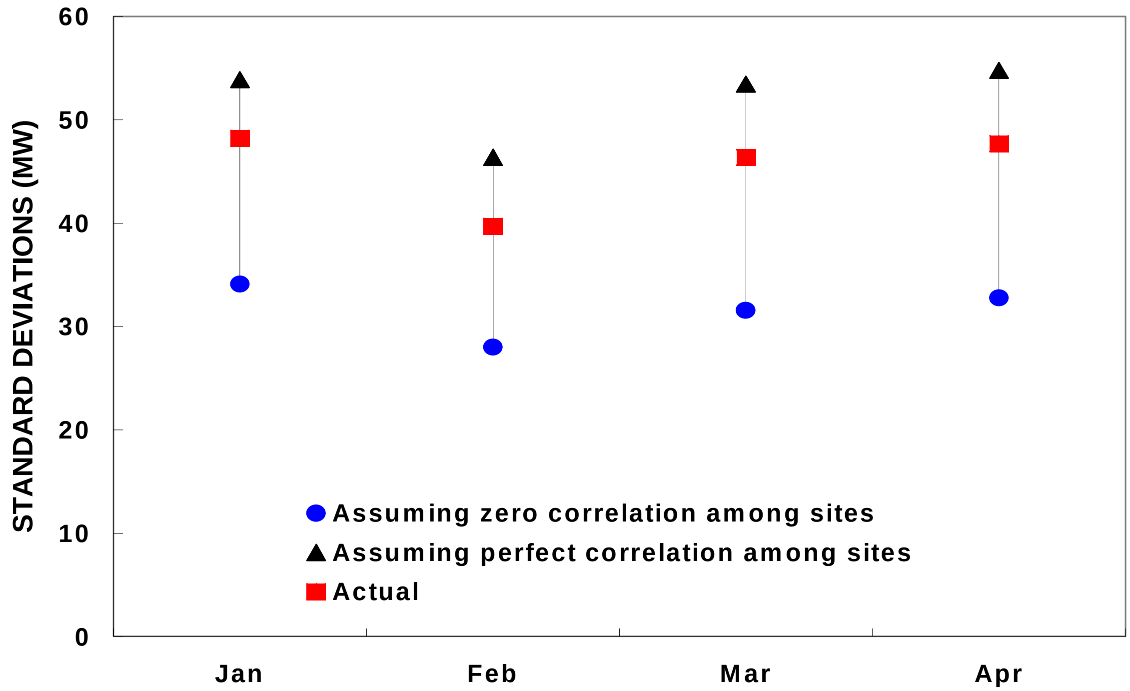
Fig. 4. **Daily wind output from four sites for February 2002. Wind-output data were missing for all of February 22.**

this figure, I assumed that the installed capacity at the Wyoming wind farm equaled that of the original four wind farms.* If the Wyoming farm was colocated with the other four, the standard deviation of the total would have been 103 MW, 30% higher than the 79 MW calculated here. This comparison demonstrates the substantial benefits of geographically dispersing wind sites.

During the four-month period analyzed here, the four wind farms produced an hourly average of 52 MW (Table 1). The wind output averaged almost 1% of the BPA system load during this time. The variability of wind output, as measured by its coefficient of variation, was much greater than that for the BPA load, 0.90 vs. 0.14.

Finally, the correlation coefficient between the wind output and system load was 0.0; in other words, there is no statistical relationship between when the wind blows and produces electricity and when BPA customers use electricity.

*This assumption ignores the reduction in wind-output variability that would occur with larger, more geographically dispersed wind farms. In essence, this assumption assumes that additional or larger turbines are installed at exactly the same locations as the existing turbines in this Wyoming wind farm.



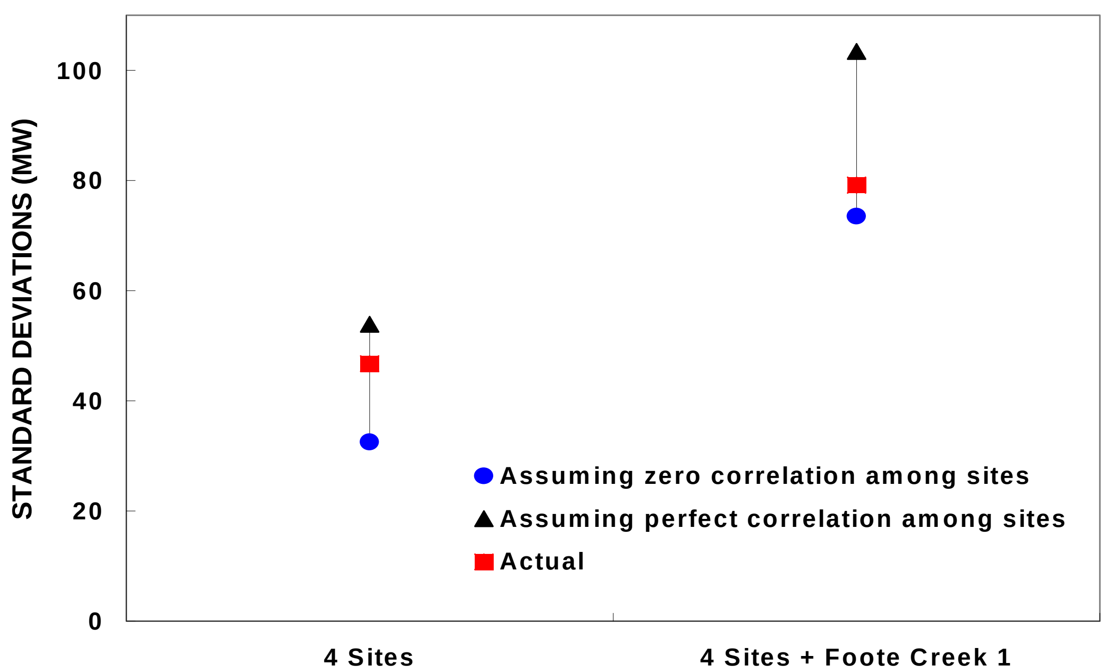


Fig. 5. **Standard deviations of hourly wind output. The top graph shows results for the four sites by month. The bottom graph shows results for the four wind farms analyzed here plus the combination of these sites and another in Wyoming. The squares are the actual values, the triangles those that would occur if there was perfect correlation among the outputs, and the circles are those that would occur if there was zero correlation among the outputs.**

Table 1. Summary data on hourly electricity output (MWh) from four wind farms and on BPA system load, January through April 2002.

	Vansycle	Stateline	Condon	Klondike	Total	BPA Load
Average	10.6	28.3	4.9	8.3	52.0	5554
Maximum	24.3	82.5	22.8	27.8	151.5	8054
Minimum	-0.2	-0.2	-0.3	-0.7	-1.1	3748
Coefficient of variation[a]	0.92	1.03	1.15	1.15	0.90	0.14
Capacity Factor	0.42	0.31	0.20	0.33	0.32	

[a]The coefficient of variation is the ratio of the standard deviation to the mean, a dimensionless measure of variability.

DAY-AHEAD LOAD AND WIND FORECAST ERRORS

UNIT COMMITMENT AND ECONOMIC DISPATCH

Vertically integrated utilities typically run their unit-commitment optimization computer programs the afternoon of the day before operations (Hirst 2001a). These large, complicated computer programs accept as inputs detailed information on the characteristics of the individual generating units that are available to produce electricity on the following day. These characteristics include current unit status, minimum and maximum output levels, ramprate limits, startup and shutdown costs and times, minimum runtimes, and unit fuel costs at various output levels. In addition, the operations planner inputs to the model the utility's DA forecast of system loads, hour by hour, as well as any scheduled wholesale sales or purchases for the following day. Finally, the inputs include details on the characteristics of the transmission system expected for the operating day (in particular, any lines or transformers out of service for maintenance).

The optimization model is then run to identify the least-cost way to meet the following day's electricity demands while maintaining reliability. The reliability requirements include the ability to withstand the loss of any single generation or transmission element while maintaining normal service to all loads. The optimization model performs two functions in its search for a least-cost solution. First, it tests different combinations of generating units that are available and, therefore, could be scheduled to operate the following day (i.e., the times each unit will start, operate, and then be turned off). Second, given the units that are online and operating during any hour, it selects the least-cost mix to meet that hour's loads.

Solving this optimization problem is complicated because of all the intertemporal constraints that generators have. For example, one unit may be cheap to operate (in terms of its variable costs, expressed in $/MWh) but may have high startup and no-load costs (expressed in $/startup and $/hour, respectively), while another unit has just the opposite characteristics. Which unit to commit depends on how many hours it is expected to operate the following day. In addition, the unit-commitment solution must respect system constraints, which include contingency-reserve and regulation requirements and transmission constraints (thermal, voltage, and stability). Finally, the optimization model must consider many different combinations of generating units that could meet the hour-by-hour loads during the day.

Once generators are committed (turned on and synchronized to the grid), they are available to deliver power to meet customer loads and reliability requirements. Utilities typically run their least-cost dispatch model every five minutes or so. This model forecasts load for the next 5-minute interval and decides how much additional (or less) generation is needed during the next interval to meet system load.* The model may look ahead several intervals (up to an hour or more) to see if any quick-start units (e.g., combustion turbines and hydroelectric units) should be turned on to meet projected demand over the next several intervals. The model then selects the least-cost combination of units that meet the need for more or less generation during the next intrahour interval. This combination must respect the constraints of each generator, including minimum and maximum operating levels and ramprates.

The primary difference between RTO and vertically-integrated-utility unit commitment and dispatch is that the RTO owns no generation resources. As a consequence, it must sign bilateral contracts, operate markets, or both to acquire the resources it needs to maintain reliability and match generation to load in real time.

FERC's (2002b) SMD devotes considerable attention to these issues. FERC proposes to require RTOs to operate integrated DA markets for energy, ancillary services (regulation and operating reserves), and transmission congestion. In addition, FERC wants RTOs to resolve RT congestion problems and energy imbalances using bids and offers, rather than engineering rules. In other words, FERC wants RTOs to dispatch the system on the basis of RT markets. With such markets in place, any differences between DA schedules and RT amounts are settled at the RT price.

As an example, consider a generator that offered 100 MW for the hour ending 10 am at $24/MWh in the DA market. Assume this offer was accepted and the market-clearing price for that hour was $26/MWh. If the unit delivered 110 MW during the hour and the RT price was only $23/MWh, the unit would receive $2830 for its energy that hour (100 MW at $26 plus 10 MW at $23). On the other hand, if the unit delivered only 95 MW during the hour, it would receive $2485 (100 MW at $26 minus 5 MW at $23).

PJM accepts bids and offers for its voluntary DA market until noon of the day before (Ott 2002). At 4 pm, it posts the results of its unit-commitment process, establishing hourly prices for energy and the regulation service and energy schedules for each generator whose offer was accepted. This schedule balances generation to load on an hourly basis, honors all scheduled interchange transactions and bilateral transactions, and meets all the transmission constraints within the PJM area. If the PJM load forecast exceeds the sum of the scheduled load, PJM will commit additional units to meet its forecast load.# If the startup and no-load costs for these PJM-committed units are not recovered from real-time energy prices, PJM pays the units for these costs and collects the same amount from customers through an uplift charge.

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*In addition, the dispatch model will seek to return the units providing the regulation ancillary service to their midpoints so these units are ready to provide the full range (up and down) of this service.

#BPA might not need to reserve additional capacity ahead of time because its hydroelectric system is so flexible in real time.

Between 4 and 6 pm, PJM accepts bids and offers for its RT balancing market, the resources it will use intrahour to balance generation to load, manage congestion, and maintain system security. PJM settles RT imbalances (the differences between actual performance and the DA schedules) on the basis of RT prices with no penalties for over- or undergeneration.

In the kinds of market-based systems described above, the inability to accurately forecast loads or generation output day ahead has very simple effects. These forecast errors are settled at RT, rather than DA, prices. Thus, the forecast errors impose risks on the users of these forecasts for the difference between DA and RT prices.

How do forecast errors affect unit commitment and operations in regions where wholesale markets are not yet so advanced? In such areas, the traditional utilities may need to commit additional resources DA to prevent reliability problems from occurring in real time if the actual and forecast output and load differ materially. Thus, the utility might incur costs to start up additional units and to run units out of economic merit order.

The next section of this chapter examines the BPA-PBL DA forecasts for hourly loads and their accuracy. The third section simulates the effects of different forecasts of wind output. The final section combines the uncertainties in DA wind and load forecasts.

BPA LOAD FORECASTS

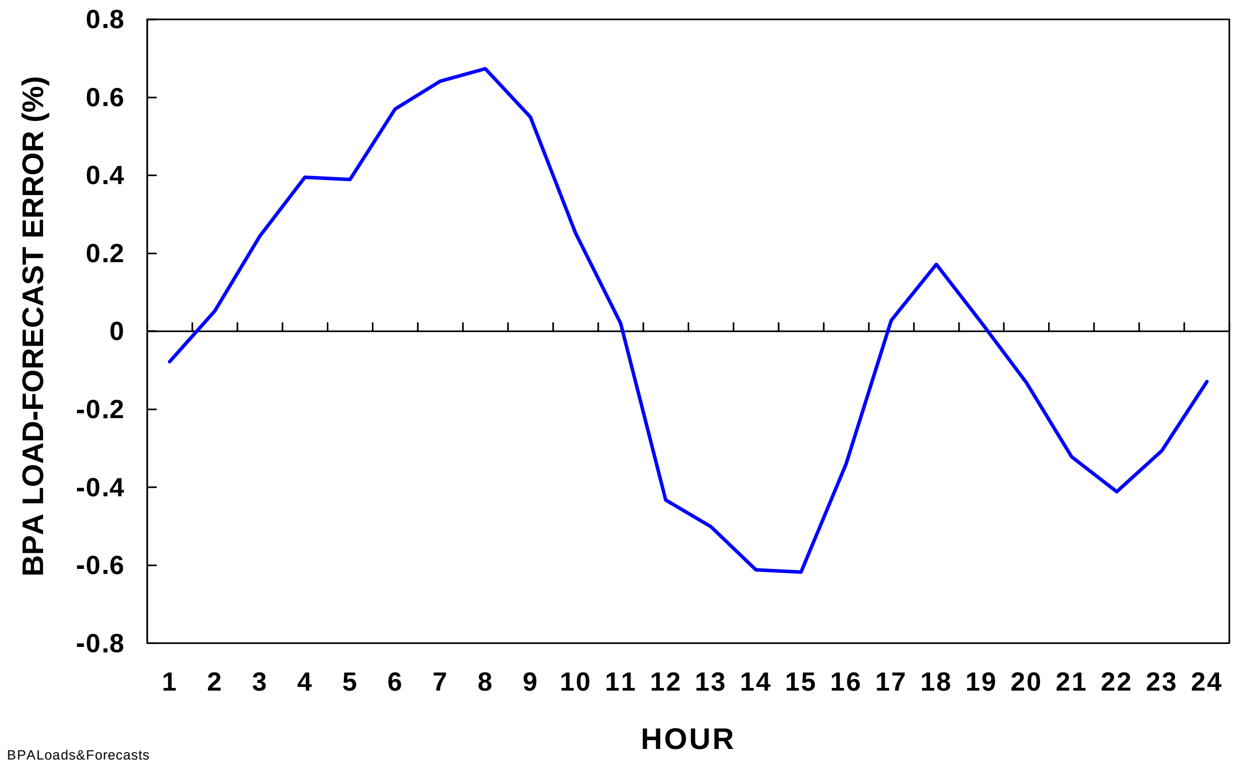
On average, the DA BPA load forecasts are quite accurate (Fig. 6), with an average error of only 0.4% of actual load for the four-month analysis period. The error averaged -5 MW, with a range from -1080 to +960 MW. These errors were roughly symmetrical (bottom part of Fig. 6). The 90% confidence interval for this forecast was roughly ±350 MW. In other words, forecast errors were larger than ±350 MW for only 10% of the hours.

The average of the absolute values of the errors was 170 MW, about 3% of total load. The 90% confidence interval for the absolute error was 10 to 430 MW.

The BPA power system faces many other uncertainties between day ahead and real time. These other factors include changes in interchange schedules, the exercise of options within contracts between other entities and BPA, and the use of the 22.5% of the BPA system assigned as "slice" to BPA customers. Additional uncertainties concern supplies, such as unit outages and precipitation and snow melt that might affect stream flows, reservoir levels, and required reservoir discharges. In aggregate, the uncertainties associated with these other factors likely exceed that associated with the DA forecast of system load.

WIND FORECASTS

Methods to forecast the energy output from wind farms fall into two general categories (Milligan 2001). Persistence models use data on wind output during prior intervals to produce



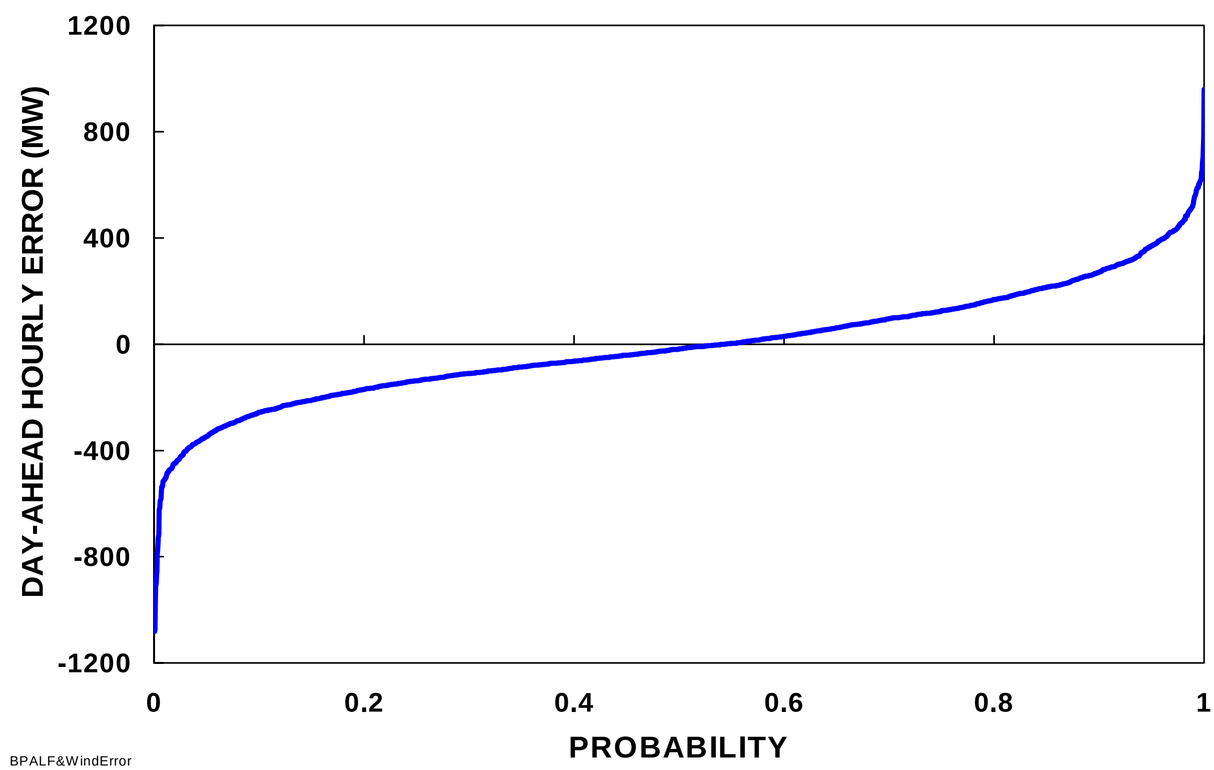


Fig. 6. **Accuracy of BPA DA hourly load forecasts. The top figure shows the average percentage error by hour, and the bottom figure shows the distribution of errors by magnitude.**

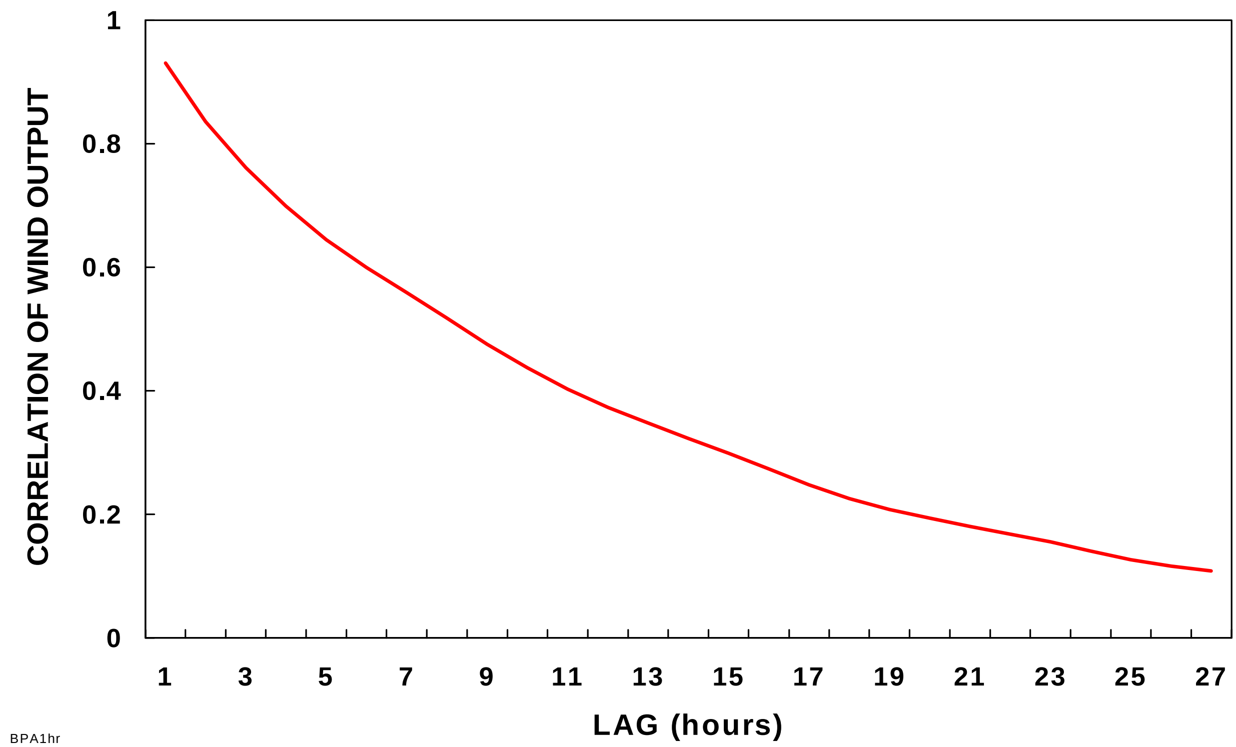


Fig. 7. The correlation (R^2) between wind output during an hour and prior hours.

forecasts from one to a few hours in the future. Meteorological models use weather data (in particular, wind speed) to forecast wind output for the next one to two days.

In a prior project involving a 100-MW wind farm in Minnesota, I developed a persistence model as a function of only two variables, the wind output two and three hours before (Hirst 2001b). This simple model explained 81% of the hourly variation in wind output.

Because the hour-to-hour correlation of wind output drops rapidly with time, persistence models are unlikely to be useful in preparing DA forecasts (Fig. 7). Although the output from the four wind farms during hour t explains more than 80% of the variation in wind output during hour $t+2$, the wind output during t explains only 14% of the variation in output 24 hours later.

Because this study did not call for development of wind-forecasting models, I developed two very simple proxies for wind forecasts to roughly bound the size of the error that might occur in practice.

- The lower bound (error #1) assumes that the hourly forecast is equal to the daily average of the wind farm's output; in other words, the output is the same hour-to-hour throughout a particular day.

- The upper bound (error #2) assumes that the hourly forecast is equal to the monthly average output of the wind farm; in other words, the output is invariant from hour to hour within a month.

In both cases, the forecast error averages to zero, in the first case over the course of each day and in the second case over the course of a month.

For the 164-MW wind capacity, the average of the absolute value of the hourly errors was 24 MW for error #1 and 41 MW for error #2 over the 4-month analysis period (Table 2). Relative to the average wind output of 52 MW, these errors equal 46% and 79%, much higher than the 3% for the DA load forecast.

Table 2. Absolute values of DA errors for 164 MW of wind, BPA load, and the combination of load and wind

	Wind Error #1[a]	Wind Error #2[b]	Load	Load + Error #1	Load + Error #2
Average	24	41	167	168	171
Standard deviation	24	21	139	139	141
90% confidence interval	1 - 77	6 - 76	10 - 433	10 - 427	13 - 435

[a]Error #1 is calculated relative to the average daily wind output.
[b]Error #2 is calculated relative to the average monthly wind output.

COMBINED WIND AND LOAD FORECAST ERRORS

Although interesting, examining the wind-forecast error in isolation says nothing about the costs of wind integration. To be meaningful, the DA error in the wind forecast needs to be assessed relative to all the other DA uncertainties facing the BPA power system. In this study, I examined only the load forecast, although many other factors (noted above) affect differences between DA estimates and RT operations.

Because the wind errors are uncorrelated with the load-forecast errors (r = 0), the wind and load errors do not sum. As shown in the right hand side of Table 2, the combined effects of errors in the wind forecast and load forecast are much less than the simple sum of the two effects. Indeed, the use of daily wind output as a predictor of wind output reduces slightly the overall DA uncertainty facing the BPA power system. On the other hand, the use of the monthly wind output increases the uncertainty slightly.

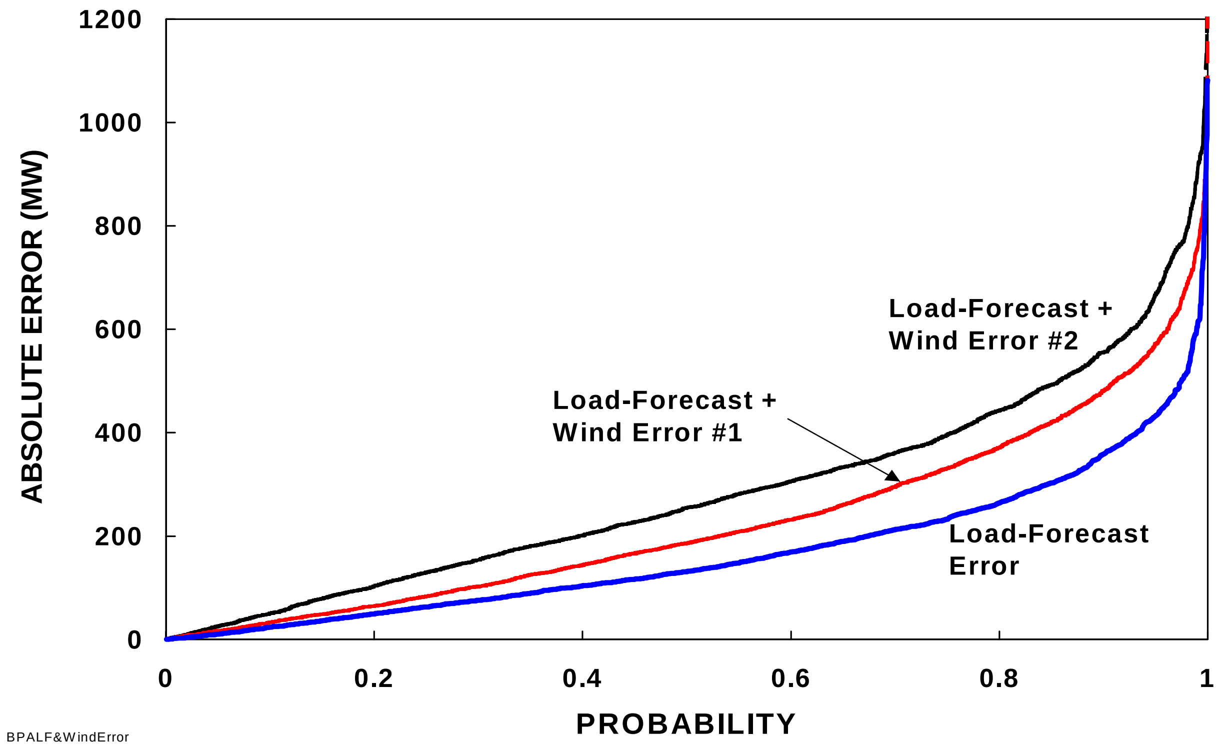


Fig. 8. **Distribution of absolute values of DA forecast errors for BPA system load and load plus 1000 of wind.**

Part of the reason for the small effect of wind-forecast error is the small size of the wind farm. Table 3 and Fig. 8 show the effects of a 1,000-MW wind farm with the same 32% capacity factor. I increased the hourly outputs from the 164-MW wind farms linearly, in essence assuming larger wind turbines at the same locations as the existing turbines. In reality, greater wind capacity would involve more wind turbines spread over a larger geographical area. Thus, the simulation results presented here for larger wind farms overestimate their variability because these results ignore the greater geographical dispersion of larger facilities (Fig. 5).

Interpretation of these probabilistic data can be complicated. Therefore, I calculated the hypothetical cost to a wind farm of its forecast error, the result of which is a single number. To make these calculations I assumed a rather high charge of $5/MW for any increase in total forecast error caused by wind.* That is, wind is charged $5/MW if its error increases a positive load-forecast error, and wind is charged $5/MW if its error reduces a negative load-forecast error. However, wind receives, in this exercise, no credit for reducing the absolute value of the total forecast error, a situation that, as noted above, occurs about half the time.

*The prices for spinning reserve, nonspinning reserve, and 30-minute reserve in New York averaged $2.56, $1.95, and $1.09/MW-hr during 2001, much less than the $5/MW-hr used here.

As was true for the combined effects of the DA forecast errors in wind and load for the 164-MW wind farms now in operation, the cost for this amount of capacity is de minimus. For 1000 MW of installed capacity, however, the wind farms would pay, on average, $320/hour (equivalent to about $1.0/MWh of wind output) with error #1 and $560/hour (equivalent to about $1.8/MWh) with error #2.[*] The bottom part of Fig. 9 shows how these costs increase with expanding wind capacity.

Figure 9 shows the effects of DA errors in wind-output forecasts as a function of wind capacity. The top part of Fig. 9 shows how the wind-forecast error combines with the load forecast error as the amount of wind capacity increases from 0 to 2000 MW, and the bottom part of the figure shows the associated costs, assuming a charge of $5/MW-hr. The addition of 1,000 MW of wind capacity (with an energy output equivalent to 6% of the BPA load) might increase the average BPA load-forecast error by 23 to 71%. Even here, however, the errors in the wind forecast offset (i.e., reduce) the overall forecast error for about 50% of the hours. This positive situation occurs because of the lack of correlation between the two sets of forecasts. On the other hand, under the worst conditions (e.g., with a probability of occurring less than 5% of the time), wind-forecast errors can increase total DA errors by about 80 MW for error #1 and 260 MW for error #2, as shown in Table 3 and on the right hand side of Fig. 8.

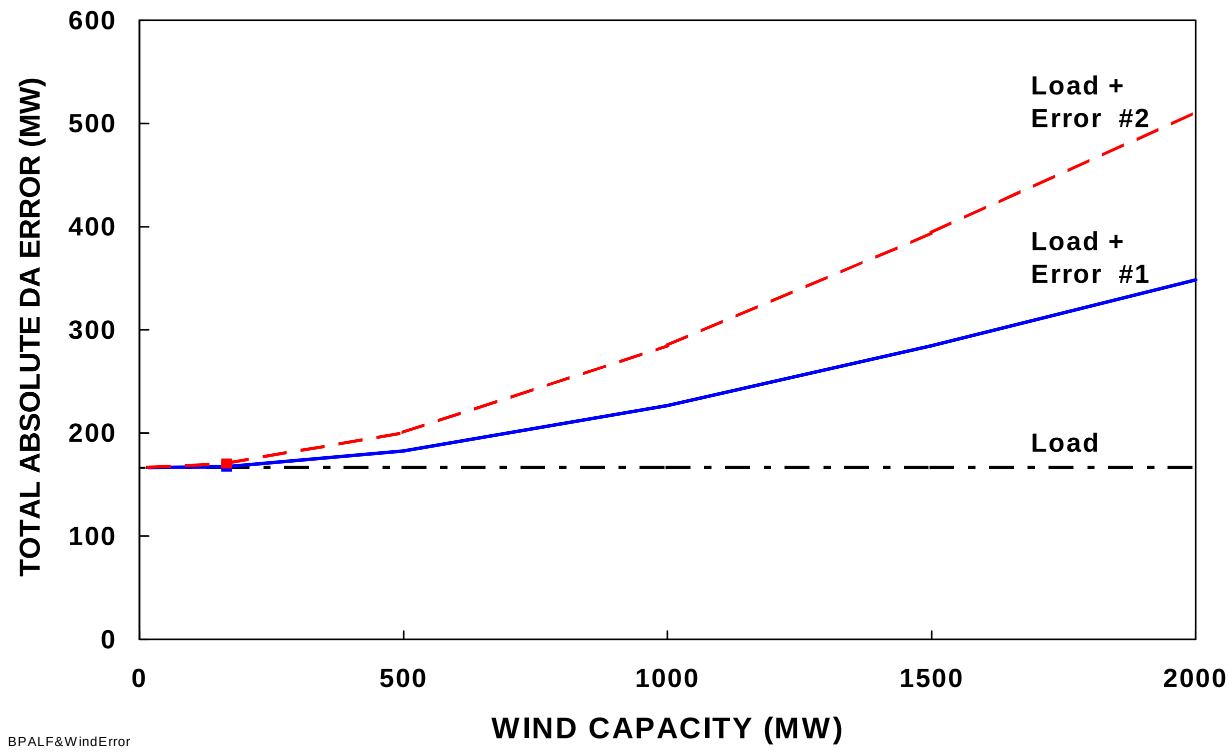
Although BPA is concerned about the effects of wind on commitment of its generating *capacity*, it may be even more concerned about the *energy* implications of errors in wind forecasts. Because BPA's generating capacity is almost exclusively hydro, its operations are much more often energy than capacity constrained. These energy constraints, related both to nonpower issues as well as to energy production, are much more important at the daily level than at the hourly level. That is, an overforecast of wind output during one hour (which causes BPA to let additional water through its turbines) that is offset by an underforecast a few hours later (which permits BPA to keep more water behind its dams) can generally be accommodated. However, persistent under- or overforecasts can cause problems.

Table 3. Absolute values of DA errors for BPA load, and the combination of load and 1000 MW of wind

	Load	Load + Error #1[a]	Load + Error #2[b]
Average	167	205	285
Standard deviation	139	163	202
90% confidence interval	10 - 433	15 - 517	26 - 668

[a]Error #1 is calculated relative to the average daily wind output.
[b]Error #2 is calculated relative to the average monthly wind output.

[*]These simple, hypothetical results suggest an annual value of $2.1 million from a more accurate wind-forecasting model (i.e., to improve the accuracy from that of error #2 to error #1).



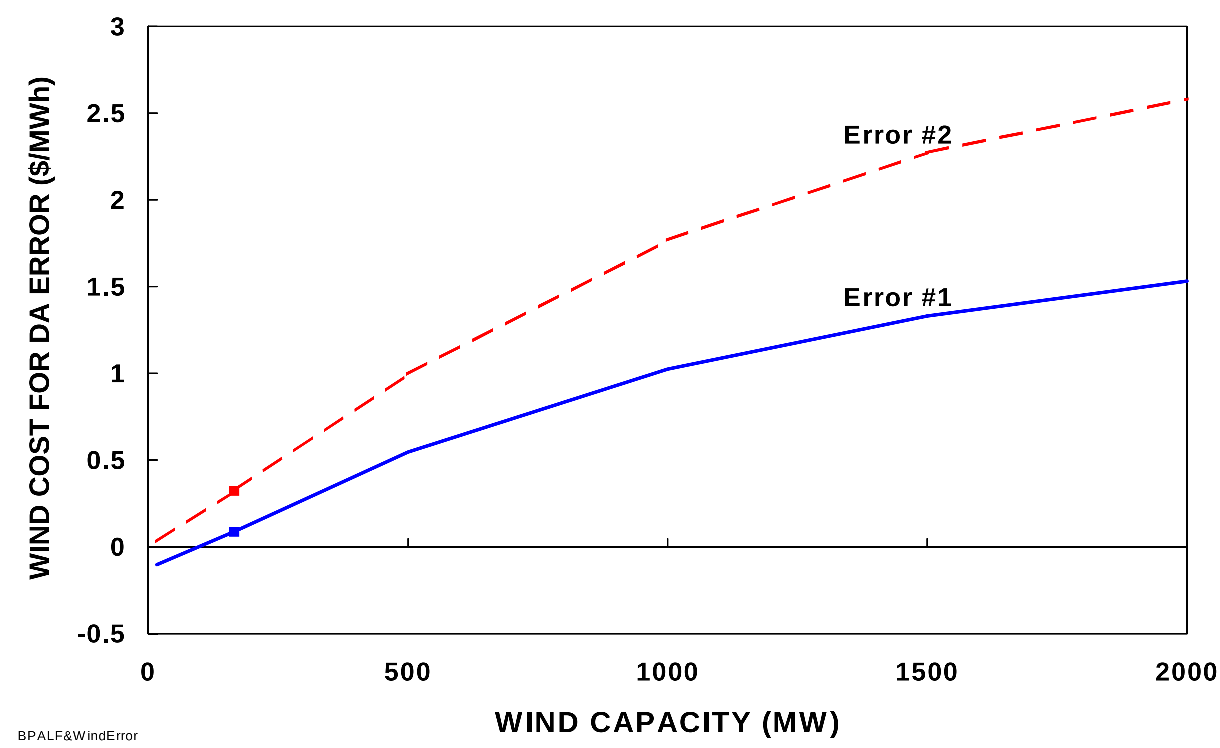


Fig. 9. **The effects of wind-farm capacity on the absolute DA error for wind and BPA system load (top) and the hypothetical cost to wind for the incremental error (bottom). The small squares represent the currently operating wind capacity of 164 MW.**

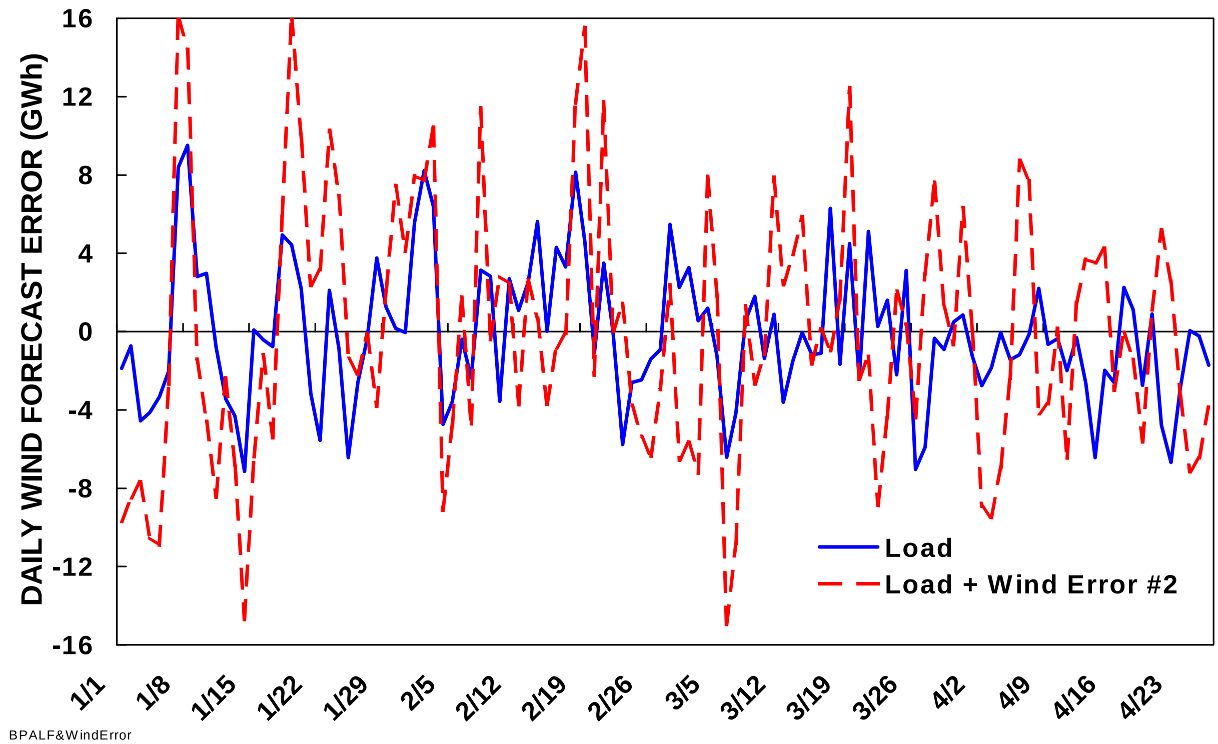


Fig. 10. **Daily energy (GWh) forecast errors for load and for load plus 1000 MW of wind.**

Although the average daily load forecast error was quite small, it varied from −7100 to +9600 MWh with a standard deviation of 3500 MWh (Fig. 10). Adding the forecast error for 1000 MW of wind capacity had almost no effect on the average, but it did increase the daily range (−15,000 to +16,100 MWh) and standard deviation (6500 MWh).* In other words, the introduction of wind increased the variability of the daily energy requirements imposed on the BPA system. This increase in standard deviation is equivalent to 5% of average daily energy consumption.

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*I consider only error #2 here because error #1, by definition, has a zero energy imbalance at the daily level.

INTRAHOUR ENERGY BALANCING

INTRODUCTION

In real time, the system operator dispatches generation (and, perhaps, some load) resources participating in its intrahour energy market to maintain the necessary balance between generation and load. Once every several minutes,* the system operator runs an economic-dispatch model to move generators up or down to follow changes in load and unscheduled generator outputs at the lowest possible operating cost. Generators that participate in the system operator's balancing market provide the load-following ancillary service.

To track changes in the minute-to-minute balance between generation and load, the system operator uses its AGC system to dispatch those generators providing the regulation ancillary service. These generators respond to short-term generation:load imbalances that are not addressed by the economic-dispatch process.

The primary purpose of these intrahour resource movements is to maintain area control error (ACE) within certain limits. ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of Interconnection frequency. In plain language, it measures how well the system operator maintains the necessary generation-load balance. The North American Electric Reliability Council (2001) established the Control Performance Standard (CPS) to determine the amount of imbalance that is permissible for reliability purposes. CPS1 measures the relationship between the control area's ACE and Interconnection frequency on a 1-minute average basis. CPS1 values can be either "good" or "bad." When frequency is above its reference value, undergeneration benefits the Interconnection by lowering frequency and leads to a good CPS1 value. Overgeneration at such times, however, would further increase frequency and lead to a bad CPS1 value. CPS1, although recorded every minute, is evaluated and reported on an annual basis. NERC sets minimum CPS1 requirements that each control area must exceed each year.

CPS2, a monthly performance standard, sets control-area-specific limits on the maximum average ACE for every 10-minute period. Control areas are permitted to exceed the CPS2 limit no more than 10% of the time. This 90% requirement means that a control area can have no more than 14.4 CPS2 violations per day, on average, during any month.

*PJM, New York, and New England use 5-minute intervals for their intrahour economic dispatch, California uses 10 minutes, and the Electric Reliability Council of Texas uses 15 minutes.

Neither CPS1 nor CPS2 requires a control area to maintain a zero ACE. Small imbalances are generally permissible, as are occasional large imbalances. Both CPS1 and 2 are statistical measures of imbalance, the first a yearly measure and the second a monthly measure. Also, both CPS standards measure the aggregate performance of a control area, not the behavior of individual loads and generators.

SPLITTING REGULATION FROM INTRAHOUR IMBALANCE

As noted above, regulation is the ancillary service that adjusts for short-term variability (minute-to-minute) in loads, and intrahour imbalance adjusts for longer-term variations in load. There is no hard-and-fast rule to define the temporal boundary between these two services. If the time chosen for the split is too short, more of the fluctuations will appear as imbalance and less as regulation. If the boundary is too long, more of the fluctuations will show up as regulation and less as intrahour imbalance. But in each case, the total volatility is unchanged and is captured by one or the other of these two services.

In practice, the temporal boundary between the two services should be based on the design of the wholesale power markets in the region of interest. That design should reflect the characteristics of the generation resources and loads in the region. Because TBL manages intrahour generation on a 5-minute basis, I defined intrahour imbalance as the linear ramp (constant movement in MW/minute) from the midpoint of one 5-minute interval to the midpoint of the next interval. Regulation is the difference between actual load each minute and the imbalance component for that minute.

Figure 11 shows the results, for one hour, of the method used to disaggregate total wind output into its regulation and intrahour-imbalance components. The average wind output for this hour was almost 87 MW, with minimum and maximum 1-minute values of 75 and 105 MW. The regulation value, by definition, averages zero for the hour, with minimum and maximum values of -2.0 and +1.9 MW; the standard deviation of these 60 values is 1.0 MW. Because the imbalance interval is so short (five minutes), the load-following component follows the raw data closely, and the regulation component is small.

REGULATION

TBL, based on detailed analysis of its ACE performance, decided it does not need to chase 1-minute ACE values (McReynolds et al. 2002). The high ramprates and rapid response times of the BPA hydro units very close track load and off-dispatch-generator movements. Thus, although BPA uses units on AGC to follow intrahour loads, it does not, strictly speaking, provide the regulation service.

Nevertheless, BPA decided to calculate the share of the BPA regulation requirement that could reasonably be assigned to wind if, at some later time, TBL decides it does need to follow 1-minute load variations. Allocating the regulation requirement to wind (or any other load or

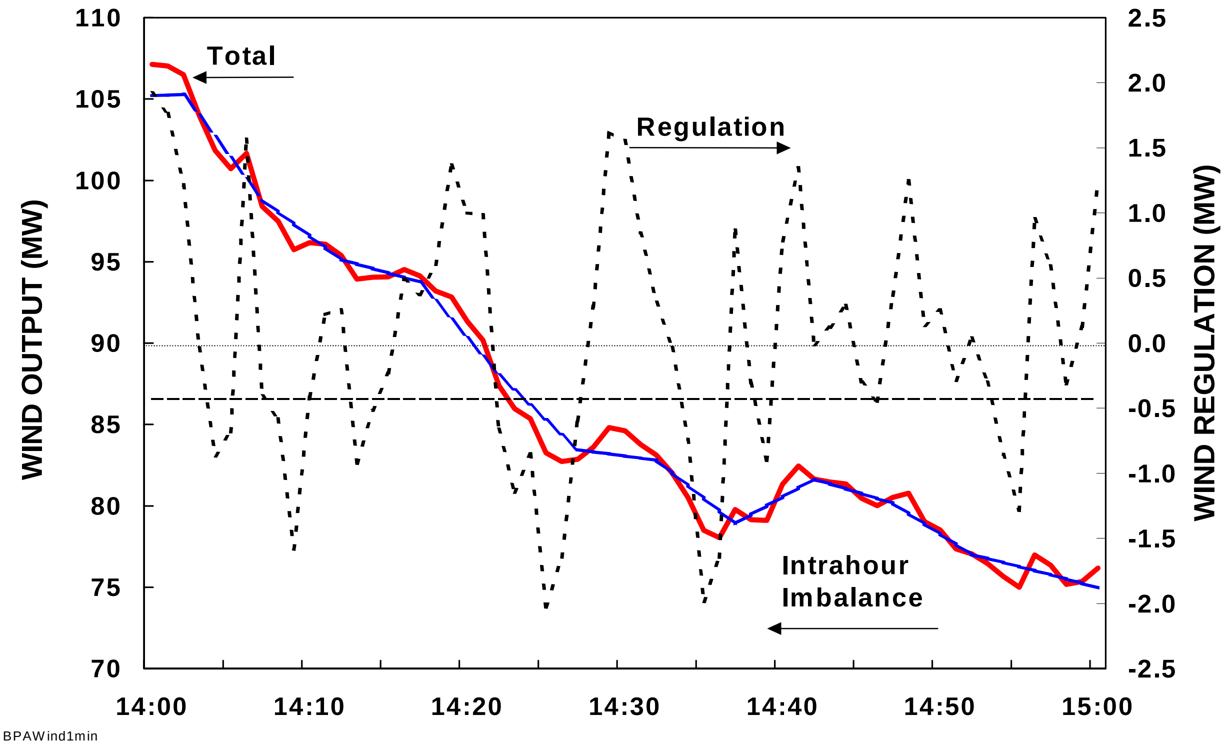
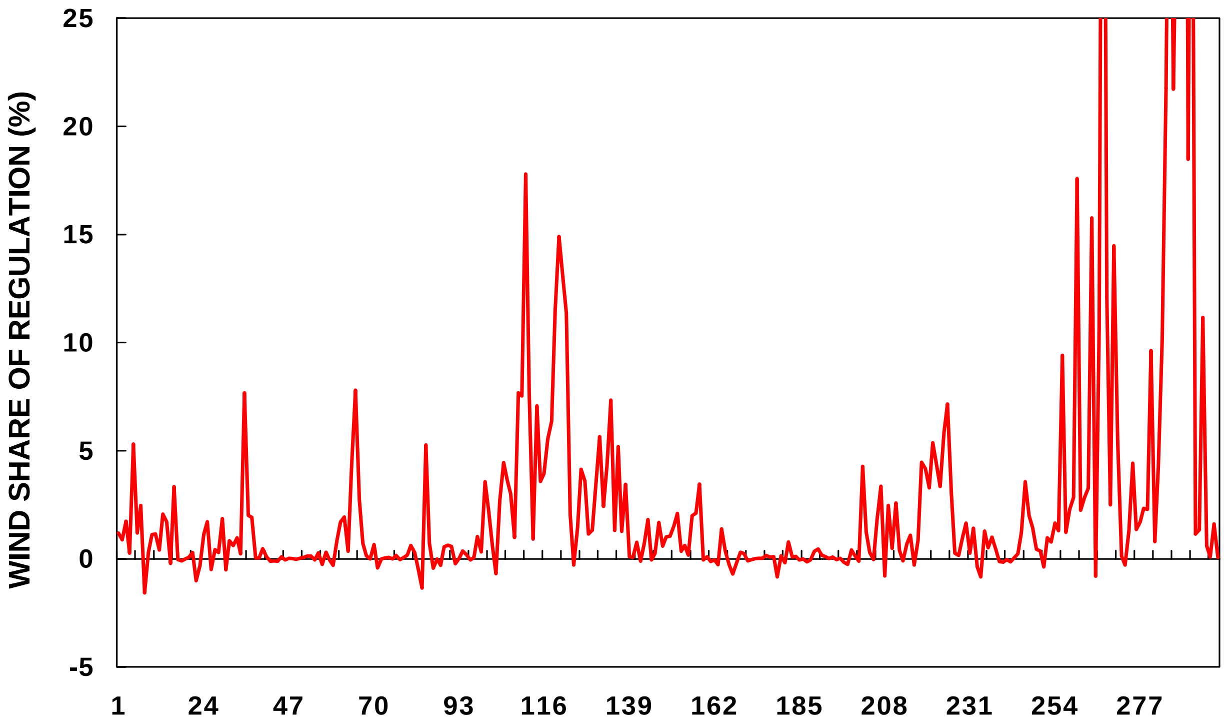


Fig. 11. Minute-by-minute wind output (total and the intrahour-imbalance and regulation components) for one hour on January 25, 2002. The output averaged 87 MW for this hour, the imbalance component ranged from 75 to 105 MW, and the regulation component ranged from −2.0 to 1.9 MW.

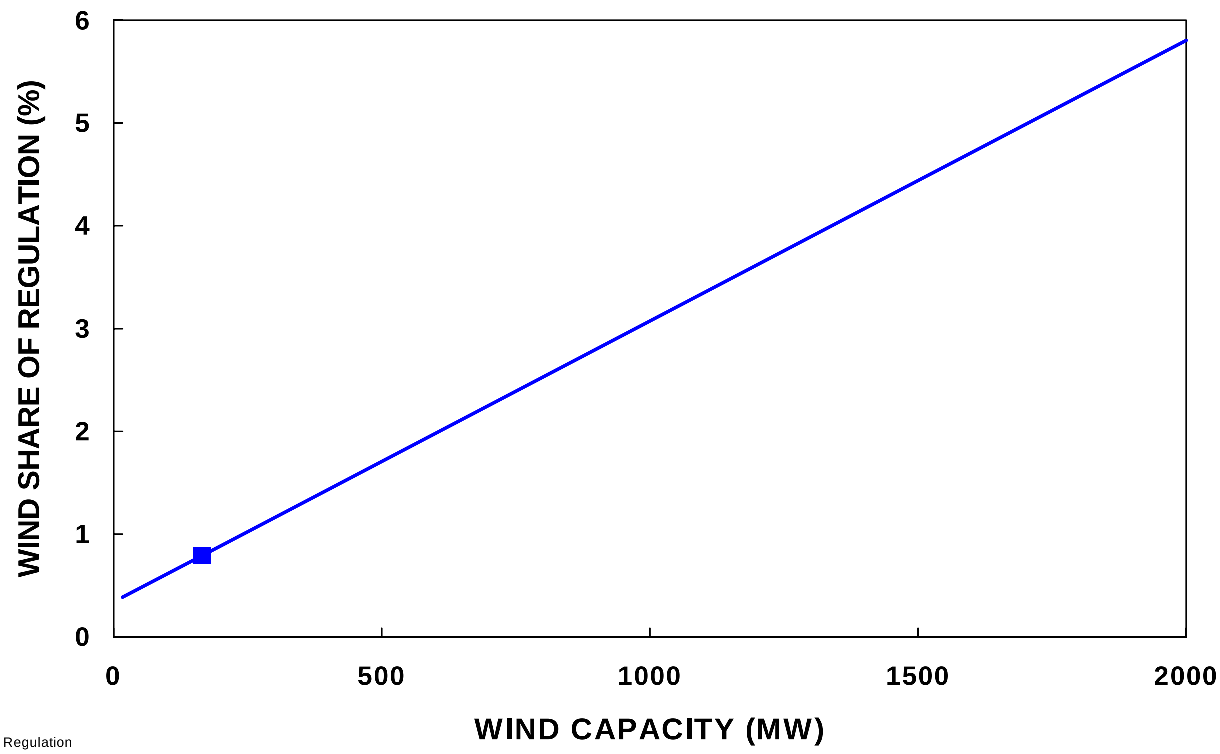
resource component, for that matter) requires 1-minute data on the resource in question as well as control-area load (Kirby and Hirst 2000). This analysis uses 1-minute data on BPA load and the four wind farms from June 18 through June 30, 2002.

During this time, control-area load averaged 4977 MW and the wind output averaged 43 MW. The standard deviation of the regulation components were 0.3% of load and 1.6% of wind output. Although the wind output was much more variable than the load, wind's share of regulation (0.8%) is very close to its share of total load (0.9%), for the original 164-MW set of four wind farms. The regulation requirement for wind is so low, once again, because the regulation components of wind and load are uncorrelated (r = 0).

To simulate the effects of larger wind farms, I increased the regulation standard deviation by the square root of the size of the wind farm. The square root function appropriately accounts for the effects of aggregation (Kirby and Hirst 2000). As the wind capacity increases, so does its share of the total regulation requirement. The top of Fig. 12 shows the hour by hour share of regulation assigned to a 1000-MW wind farm. Although the average is 3.1%, it varies substantially from hour to hour as a function of wind and load variabilities. As the wind-farm capacity increases, its share of regulation also increases. But the regulation share increases more slowly than does the wind capacity because of the diversity effect of wind (bottom of Fig. 12).



Regulation



Regulation

Fig. 12. **The percentage of BPA regulation requirement for 1000 MW of wind, hour by hour, for the last 13 days of June 2002 (top) and the share of regulation that wind accounts for as a function of wind capacity (bottom).**

For example, although 1000 MW is 6.1 times the original 164 MW, the larger (hypothetical) wind farms' regulation requirement is only 3.9 times that of the original wind farms.

Once again, I estimate the possible cost to a wind farm of integration. BPA nominally assigns 149 MW, on average, of its generation on AGC to the regulation service. The average price of the regulation service for the New York ISO was about $11/MW-hr during 2001. Thus, for BPA, the hourly cost of regulation at the New York average price would be $1639. A 1000-MW wind farm, according to this analysis, would pay $0.19/MWh for the regulation service.

LOAD FOLLOWING

Based on the discussion above, I defined the intrahour load-following requirement, for either load or wind, as the signed difference between the highest and lowest 5-minute average load during each hour. Figure 13 illustrates how this method works, for a 2-hour period. During this time, the load increased steadily with load-following requirements of 701 and 866 MW for the two hours. On the other hand, the wind output increased during the first hour and then dropped during the second hour, leading to load-following requirements of −12.5 and 21.8 MW.*

Because the load-following requirements of wind and load are uncorrelated (r = 0), wind has little effect on total load-following requirements (Table 4 and Fig. 14). Specifically, the simulated 1000-MW wind farms increase the average load-following requirement by only 10 MW and have virtually no effect on either the standard deviation or 90% confidence interval of load-following requirements.

Table 4. Absolute values of hourly load-following requirements for BPA load, 1000 MW of wind, and the combination of load and wind

	Load	Wind	Load + Wind
Average	280	70	290
Standard deviation	190	70	190
90% confidence interval	79 – 682	2 – 218	92 – 692

As was true for the discussion of DA forecast errors, interpreting probabilistic results can be ambiguous. Therefore, once again, I calculated the hypothetical cost to a wind farm for its load-following requirements, which yields a single number. Again, I assumed a $5/MW-hr cost

*The signs are reversed on the wind values so that positive values of load following mean that BPA must provide additional capacity (i.e., because loads are higher or wind output is less than forecast).

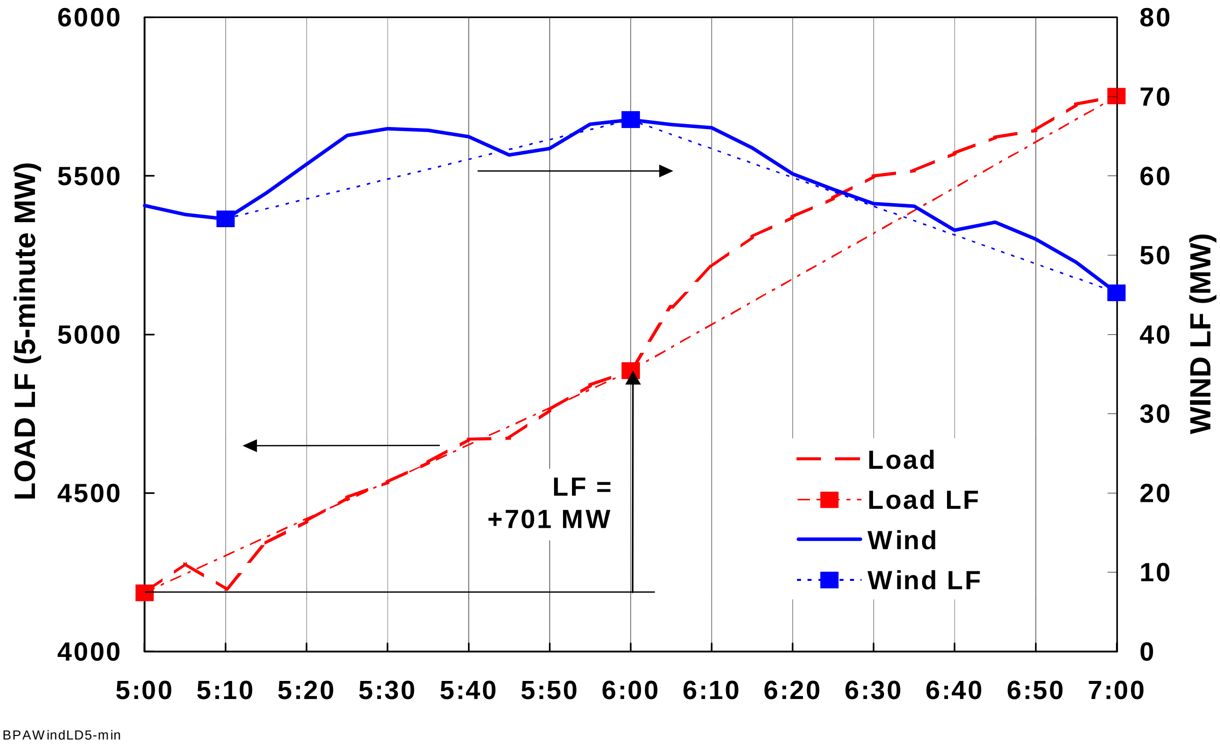


Fig. 13. **Load-following requirements for BPA load (left axis) and wind output (right axis) for two hours on January 9, 2002.**

for load following in either the up or down direction. As before, wind receives no credit for reducing the overall load-following requirement, which occurs in 52% of the hours. For 1000 MW of installed capacity, the wind farm would pay, on average, $87/hour, equivalent to about $0.28/MWh for load following.

The amount of extra capacity required to provide load following for wind increases only slightly with increasing wind capacity (top of Fig. 15). Similarly, the cost to a wind farm for this service increases only slowly with wind capacity (bottom of Fig. 15).

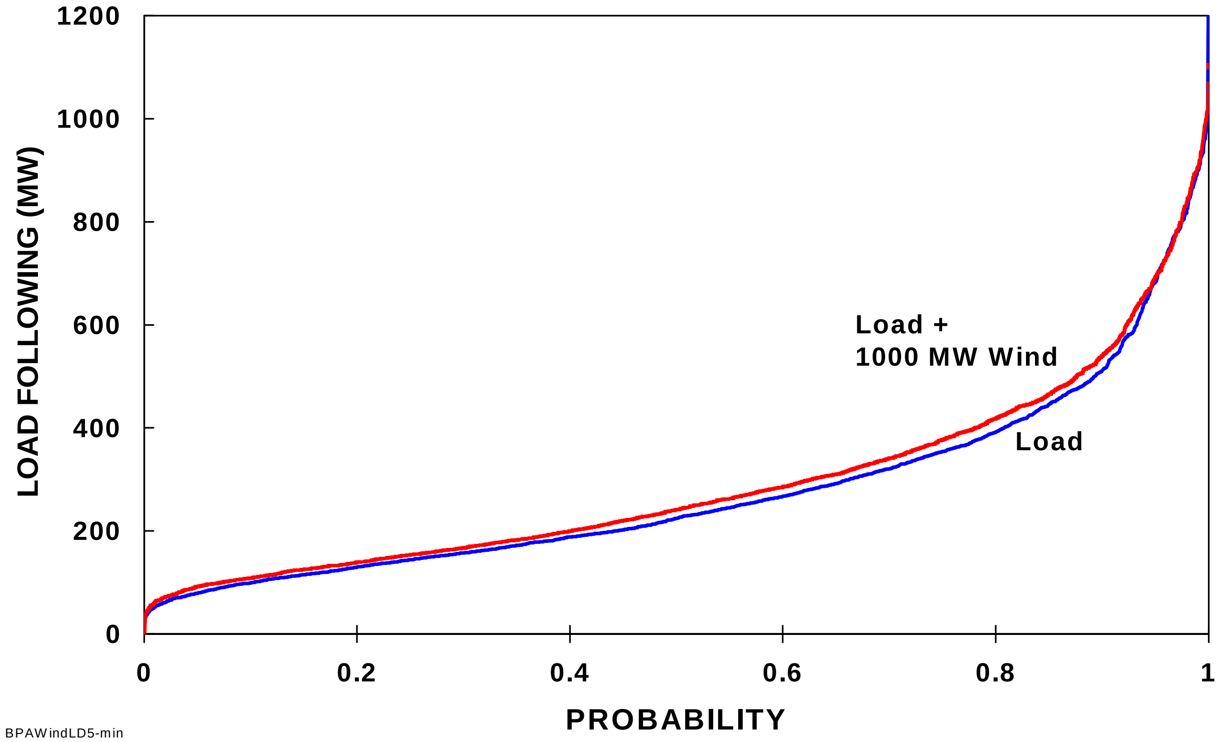


Fig. 14. Distribution of absolute values of hourly load-following requirements for BPA control-area load and load plus 1000 MW of wind.

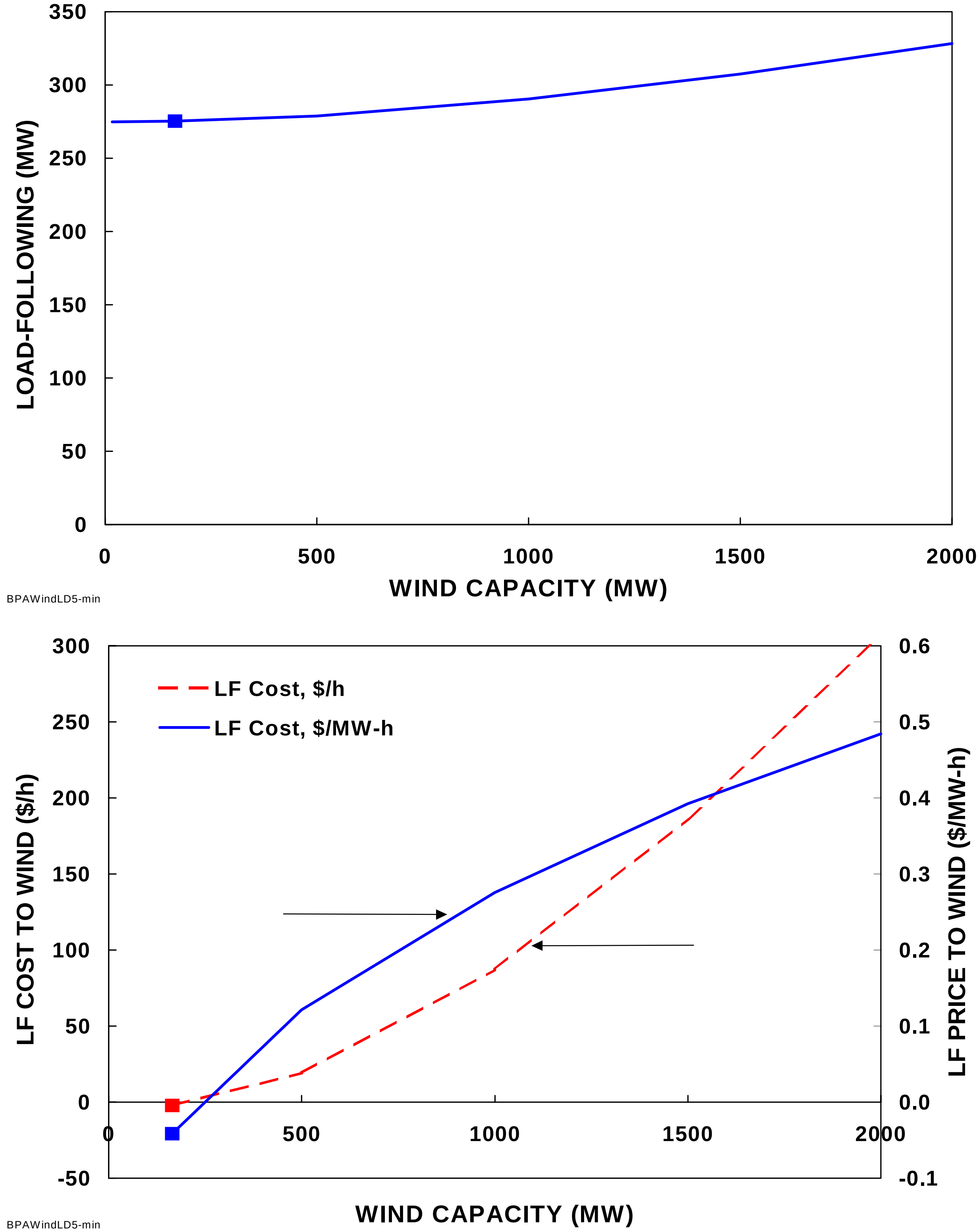


Fig. 15. **The effects of wind-farm capacity on the absolute value of the load-following requirement (top) and the hypothetical cost to wind for load following (bottom).**

COMBINED EFFECTS

In this chapter, I assess the ability of the BPA hydroelectric system to respond to the uncertainties associated with DA forecast errors and RT regulation and intrahour balancing requirements. That is, I combine the results in chapters 5 and 6 with the amount of capacity BPA has available in real time that is not needed to meet load or provide ancillary services (regulation, spinning reserve, and supplemental reserve).

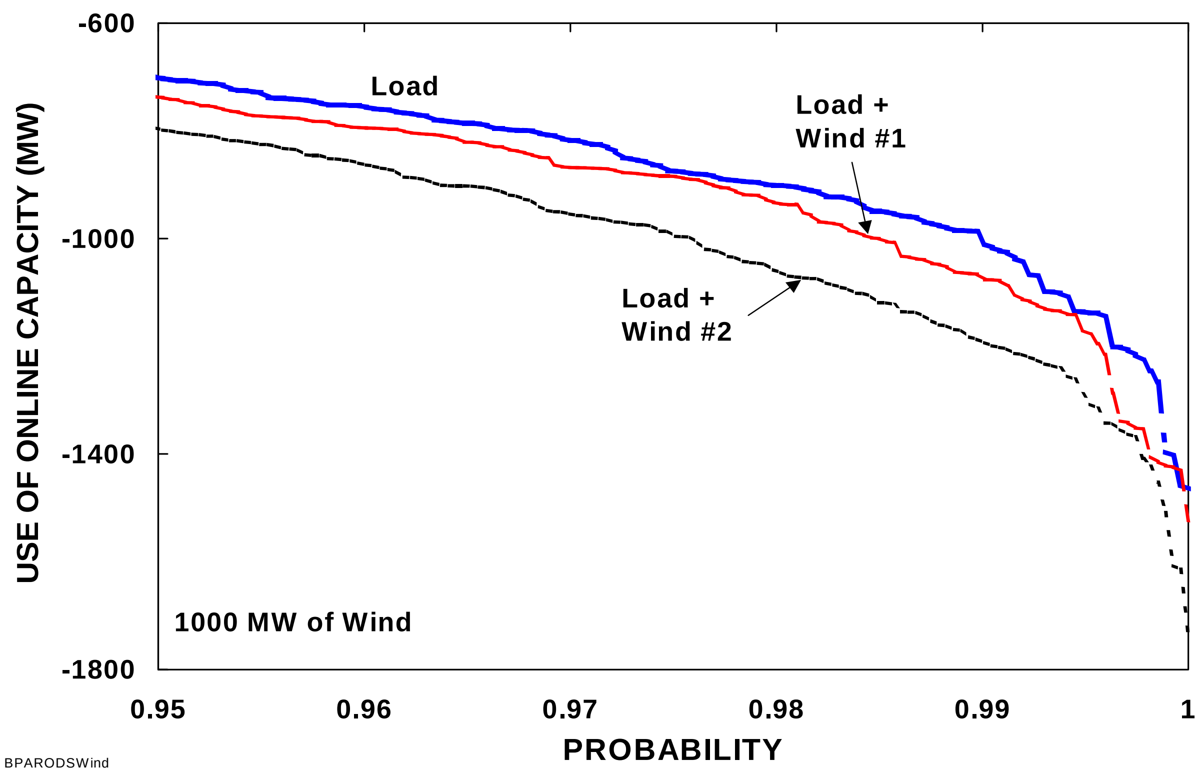
TBL maintains hourly data on the amounts of capacity that can be made available within ten minutes. Units are classified as:

- Control reserve, extra capacity not needed to meet load from units on AGC that can provide regulation;
- Spinning reserve, extra capacity not needed to meet load from units online and synchronized to the grid, including control reserve; and
- Operating reserve, extra capacity not needed to meet load from units offline and available within 10 minutes, including spinning reserve.

TBL also maintains hourly data on the capacity obligations for each of these three categories. The difference between the amounts available and required is surplus to BPA's immediate needs and could be used to offset the uncertainties associated with inaccurate load and wind forecasts, other factors that might have changed between the time DA schedules were set and real time, and the intrahour variations in load and resources (including wind).

In reality, not all this surplus capacity can be converted into energy. The extent to which additional energy can be produced at these hydroelectric projects during a particular hour depends on the maintenance and operating status of each unit, unit ramprates, unit limits related to water hammer and droop settings, as well as reservoir levels, stream flows, and nonelectric constraints on these levels and flows. BPA staff suggested I use data from only the Big 10 projects instead of data from all the BPA projects and that I "derate" the available capacity amounts by 15% to convert from instantaneous to sustained capability (McReynolds 2002).

Adding the DA forecast errors and intrahour balancing requirements for load and wind has very little effect. The top of Fig. 16 shows these results for the worst 5% of the hours, i.e., for those hours when the amount of remaining surplus is smallest. Even here, the effects of 1000 MW of wind are small, consuming an average of less than 100 MW. As the amount of wind capacity increases, more "excess" capacity is needed. As shown in the bottom of Fig. 16, this effect is quite modest. Even at the 95% probability level, 1000 MW of wind would require less than 100 MW of generating capacity to offset DA forecast errors and RT volatility.



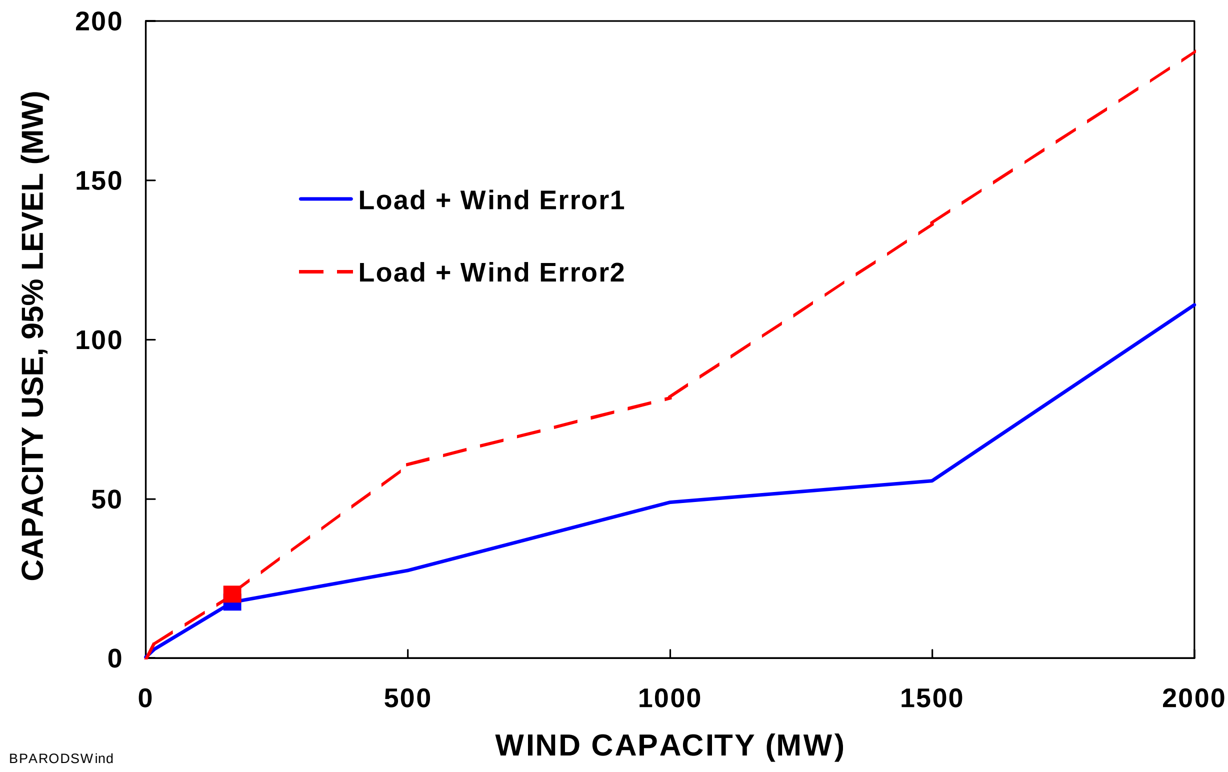


Fig. 16. **Load and wind use of capacity under extreme conditions (95% probability). The top graph shows the upper ends of the distributions, and the bottom graph shows wind use of BPA capacity as a function of wind capacity.**

CONCLUSIONS

This study analyzed data for the first four months of 2002 on wind-farm electricity output and the BPA power system. Wherever assumptions were required, I chose ones that were unfavorable to wind (i.e., that increased the costs of integrating wind with the BPA system). These conservative assumptions include (1) stylized wind forecasts, the second of which can surely be improved upon; (2) scaling to larger wind farms that ignores the diversity benefits of geographical dispersion; and (3) use of a high price ($5/MW-hr) for capacity required in real time that was not scheduled day ahead. As a consequence, wind farms are likely to require fewer BPA resources at a lower cost than estimated here.

In addition, these results are based on only four months of data rather than a full year. Because the physics and costs of running the BPA power system are highly seasonal,[*] these initial results should be viewed cautiously. Finally, these results ignore transmission, implicitly assuming the locations of wind farms are irrelevant (i.e., wind output can be transmitted to load centers with zero losses and no congestion).

Wind output is quite variable on a minute-to-minute and hour-to-hour basis. However, the outputs of the four wind farms analyzed here are largely uncorrelated with BPA loads. As a consequence, the inability to accurately predict and control wind output has only modest effects when considered in the context of the many uncertainties that affect the generation:load balance for the BPA system.

Table 5 summarizes the results of the data and analyses discussed in chapters 3 through 7. Roughly speaking, a 1000-MW wind farm might increase (or decrease) the amount of capacity BPA needs online at any time by about 100 MW, depending on the accuracy of the DA wind forecast. As shown on the right of Table 5, these effects are roughly symmetrical, which means that, on average, wind has almost no effect on BPA capacity requirements. The cost to integrate wind with the BPA power system, including adjustments for DA forecast errors and RT regulation and load following requirements, is likely to be well under $5/MWh of wind output for 1000 MW of wind capacity.

[*]BPA loads peak in the winter, but the rest of the WECC is summer peaking. Water availability is also strongly seasonal, depending on the amounts and timing of rain, snowfall, and snowmelt. The amount and flexibility of BPA's hydro capability varies with loads, water conditions, and biological requirements.

Table 5. Summary of results on the incremental capacity (MW) required for 1000 MW of wind capacity[a]

	Absolute values[b]		Values[c]	
	Average	95% limit	Average	95% limit
Day-ahead forecast error				
Error #1	40	85	0	60
Error #2	120	235	0	230
Regulation	5	20	5	20
Load following	15	25	0	5
Totals	60 to 140	70 to 185	5	35 to 90

[a]These values are those that occur when the combination of surplus capacity is lowest and the load forecast error, wind error, and real-time balancing requirements are greatest.

[b]These values ignore the sign of the wind effect, treating increases and decreases the same (i.e., all changes are positive).

[c]These are the actual algebraic values of the effects of wind on BPA capacity.

Because wind's effects on the BPA system are small and roughly symmetrical, there is no simple answer to the question: how much capacity should BPA set aside day-ahead to allow for uncertainties in the real-time output of wind farms. Answering this question is difficult for several reasons.

First, BPA has sufficient capacity to be able to ignore the uncertainties associated with other factors that affect differences between DA plans and RT operations; in particular, errors in BPA's DA system load forecast are not used in operational planning. Based on results for the first four months of 2002, this capacity is enough to cover the uncertainties associated with as much as a few thousand MW of wind capacity. (The amount of capacity available might be much less during other seasons.)

Second, responding to wind uncertainty (as well as to other uncertainties) is a function of risk management. Cautious system planners and operators will err on the side of having more physical capacity available. Profit-oriented planners and traders, on the other hand, will aggressively seek opportunities to buy and sell in all time frames, from day ahead to hour ahead.

Finally, BPA lacks data and analysis to document the costs associated with uncertainties in DA load forecasts, generator schedules, interchange schedules, precipitation, customer use of their slice entitlements, or other factors that might lead to differences between DA expectations and RT operations. Understanding the nature and magnitude of these factors is essential to placing wind uncertainty in the appropriate context. That is, the effects of variability in wind output do not occur in isolation; they need to be analyzed along with all the other factors that affect BPA hydroelectric operations. As shown here, the errors in the DA forecasts of wind and load are uncorrelated, which means that the combined effect is much less than the sum of the factors separately.

The large amounts of hydro capacity that are generally online, not fully loaded, and not at their minimum operating levels suggests that large amounts of wind could be accommodated within the BPA system at very little cost. There are two problems with this statement. First, it is qualitative and says nothing about the magnitude of these costs (even if they are small). Second, during certain hours and seasons, BPA may not have spare capacity to quickly respond to changes in wind output. Similarly, as wind capacity in the Pacific Northwest increases, a time will come when a threshold is passed, at which point the costs of wind integration may be much higher.

BPA should encourage the wind community to develop accurate wind-output forecasting methods that operate day ahead (e.g., provide reasonable forecasts 12 to 36 hours ahead of operation). The use of such forecasts would yield more accurate DA schedules of wind output, which, in turn, would reduce the capacity adjustments BPA needs to make between DA and RT.

The analyses conducted here provide useful qualitative guidance to BPA on how wind resources might affect operation of the BPA system and the ability to market power from that system. Therefore, the analyses presented here for the first four months of this year should be repeated as additional data become available (e.g., with a full year of data). Such additional analysis is important because of the strong seasonality of BPA hydroelectric power supplies and electricity demand.

Finally, BPA might analyze the costs of wind integration using the kinds of DA and RT markets called for by FERC's (2002b) standard market design. Such an exercise would involve estimation of DA prices for hourly energy and regulation, as well as RT (hourly and intrahour) prices for energy. These prices would be applied to DA wind schedules, to the differences in intrahour system fluctuations with and without wind (to calculate regulation and load-following costs), and to the differences between RT deliveries of wind energy and DA schedules.

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