INTERACTIONS OF WIND FARMS WITH BULK-POWER OPERATIONS AND MARKETS

Eric Hirst
Consulting in Electric-Industry Restructuring
Oak Ridge, Tennessee 37830

September 2001

Prepared for
Project for Sustainable FERC Energy Policy
Alexandria, Virginia 22314
Terry Black, Project Manager

CONTENTS

Page

SUMMARY v

LIST OF ACRONYMS vii

1. INTRODUCTION 1
    CONTROL AREAS 3
    PROJECT SCOPE 6

2. DATA INPUTS 9
    WIND RESOURCE 9
    CONTROL AREA 9

3. LAKE BENTON AND PJM CHARACTERISTICS 13
    LAKE BENTON WIND CHARACTERISTICS 13
    PJM CHARACTERISTICS 16

4. ANALYTICAL APPROACH 21
    FORECASTING WIND OUTPUT 21
    SPLITTING REGULATION FROM INTRAHOUR IMBALANCE 22
    ALLOCATION OF REGULATION REQUIREMENT 24
    INTRAHOUR BALANCING 26
    OTHER PARAMETERS 30
    WIND REVENUES 31

5. RESULTS 33
    AUGUST 2000 33
    JANUARY 2001 36

6. CONCLUSIONS 39

ACKNOWLEDGMENTS 40

REFERENCES 41

SUMMARY

The amount of wind generating capacity in the United States is increasing rapidly (e.g., from 2600 MW at the beginning of 2001 to 4000 MW at the end of the year). As wind becomes a larger share of total generating capacity, issues related to its integration with bulk-power operations and markets are becoming increasingly important.

Such integration of wind is qualitatively different from that for other types of generators because wind output depends on whether, when, and how hard the wind blows. Compared to conventional generators, wind's output is relatively uncontrollable, unpredictable, and variable. Because of these characteristics and because electric-system operators have little experience with wind facilities, considerable disagreement exists about the costs of integrating wind into electrical systems. On the one hand, wind advocates suggest that the small size of most wind farms implies that their output will be largely invisible (and therefore cost free) to a large electric system. On the other hand, some utilities suggest that every unscheduled megawatt movement of a wind farm must be offset, megawatt for megawatt, by some other resource, generally at high cost.

Neither perspective is correct, and neither perspective is informed by data and analysis. This report develops and applies a quantitative method for the integration of a wind resource into a large electric system. It focuses on the real-time operations and short-term markets in a competitive wholesale electricity industry, encompassing three time dimensions of the wind output:

- Hour-ahead energy market, which provides the last opportunity for a generator (or load) to modify its schedule and obtain a firm price for its scheduled output (or consumption) for a particular operating hour. In the method developed here, this market permits the wind-farm operator to sell its expected output in a particular hour using a forecast of wind output based on its output two or more hours earlier.

- Real-time (intrahour) balancing market, in which unscheduled resources and loads appear. These unscheduled amounts are the differences between the actual resource or load during a particular interval within the operating hour and the hour-ahead scheduled values.

- Regulation, which charges the individual resource for the effects of its minute-to-minute volatility in output relative to the volatility of the total system load.

A key feature of the present analysis is its *integration* of wind with the overall electrical system. The uncontrollable, unpredictable, and variable nature of wind output is not analyzed in isolation. Rather, as is true for all loads and resources, the wind output is *aggregated* with all the other resources and loads to analyze the net effects of wind on the power system. Aggregation is a powerful mechanism used by the electricity industry to lower costs to all consumers. Such aggregation means that the system operator need not offset wind output on a megawatt-for-megawatt basis. Rather, all the operator need do, when unscheduled wind output appears on its system, is maintain its average reliability performance at the same level it would have without the wind resource.

The results developed with this method suggest that (1) wind-farm owners can increase their earnings by scheduling wind output ahead of time rather than having the wind energy appear entirely in real time (Fig. S-1), (2) improved forecasting models can increase the revenues associated with hour-ahead scheduling, and (3) the average revenue per MWh of wind production declines as the size of the wind facility increases relative to the size of the electrical system. The results developed here show how strongly wind revenues depend on hourly prices for energy and ancillary services. These results suggest that wind developers should focus not just on locations with high wind speeds but also on locations with high energy prices.

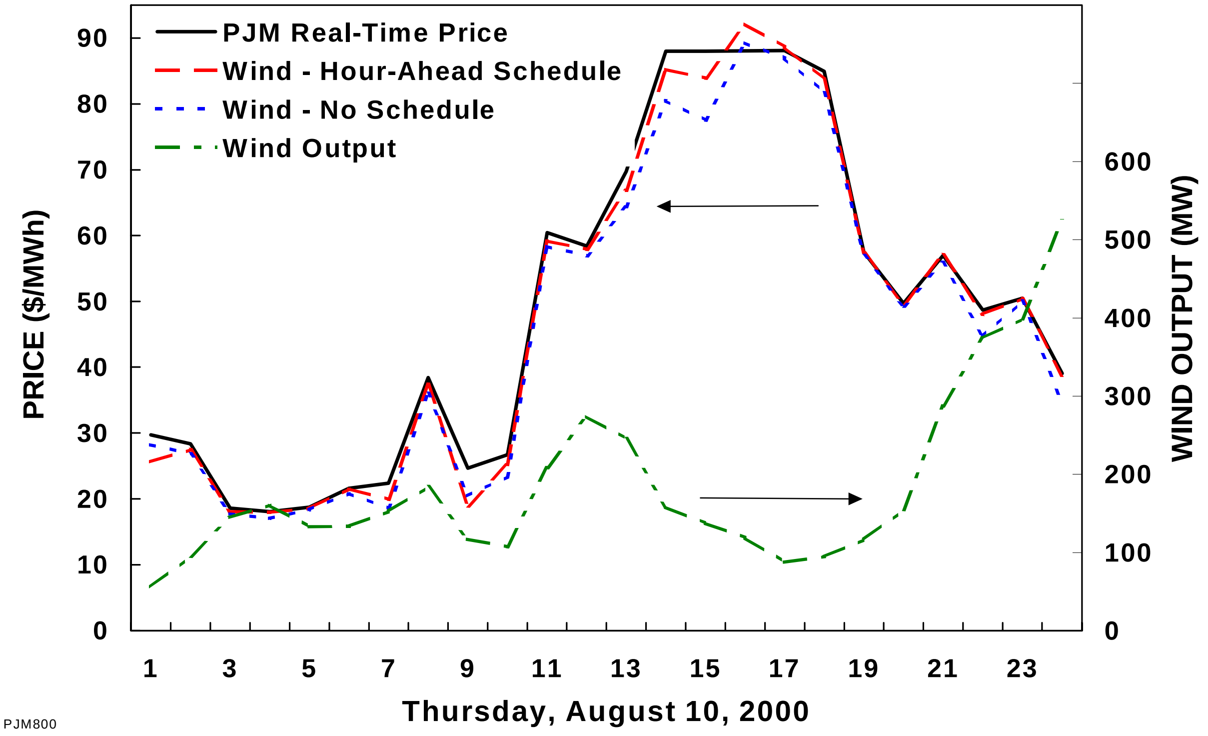


Fig. S-1. Hourly wind output (right axis) and hourly prices (left axis) for PJM real-time market, wind power scheduled hour ahead, and wind power if it does not schedule its output ahead of time.

LIST OF ACRONYMS

ACE	Area control error
CPS	Control Performance Standard
DA	Day ahead
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
HA	Hour ahead
ISO	Independent system operator
LB	Lake Benton
NERC	North American Electric Reliability Council
PF	Penalty factor
PJM	Pennsylvania, New Jersey, Maryland Interconnection, LLC
RT	Real time
RTO	Regional transmission organization
UWIG	Utility Wind Interest Group

INTRODUCTION

Wind, as a source of electricity, has two wonderful attributes. First, unlike conventional fossil-fuel-fired generators, a wind farm emits no air pollutants. Second, it has extremely low operating costs; unlike almost all other generators, a wind farm consumes no fuel for which it has to pay.

On the other hand, wind farms have three characteristics that complicate their widespread application as an electricity resource:

- Limited control: While the output of most generators can be controlled by the unit operator, often on a minute-to-minute basis, the output from a wind farm depends entirely on current wind speed and is, therefore, outside the control of its human operators. (Of course, the wind output could be capped or the turbines taken offline, which might be useful in some situations.)
- Relatively unpredictable: While the output of most generators, because they can be controlled by operators, is predictable, this is less true for wind farms. To the extent one can forecast weather conditions, in particular wind speed, wind operators can predict, although imperfectly, the future output of their facilities.
- Variable: Because the output of most generators can be controlled, their volatility (i.e., minute-to-minute variations in output) can also be controlled. That is, output can either be maintained at a near-uniform level or it can intentionally be varied from minute to minute to provide what is called the regulation ancillary service (explained below). Wind output cannot be similarly controlled because it is determined by time-varying wind speeds—it varies from minute to minute, as well as from hour to hour and day to day.

Because of these three characteristics, the integration of wind output into a bulk-power electric system is qualitatively different from that of other types of generators.[*] As the Energy Information Administration (2000) notes, "intermittent availability [is] … expected to continue to disadvantage wind power relative to conventional generating technologies." The electric-system operator must move other generators up or down to offset the uncontrollable,

---

[*] The output from conventional generators is, to some extent, uncontrollable, unpredictable, and variable. For example, all generators suffer from occasional forced outages, when equipment suddenly fails and the unit stops producing electricity. The average forced outage rate for all fossil units is about 8% (North American Electric Reliability Council 2000).

unpredictable, and variable wind fluctuations. Such movements raise the costs of fuel and maintenance for these other generators.

Not only is wind power different, it is new. Because it is new, the operators of bulk-power systems have limited experience in integrating wind output into the larger system. Today, wind accounts for 0.1% of U.S. electricity production (Interlaboratory Working Group 2000).[*] As a consequence of its newness, market rules that treat wind fairly—neither subsidizing nor penalizing its operation—have not yet been developed.

The lack of data and analytical methods encourages wind advocates and skeptics to rely primarily on their biases and beliefs in suggesting how wind should be integrated into bulk-power systems. In some cases, utilities have estimated the cost of such integration equal to a large fraction of the wind-farm's capital cost, based on essentially no data. Wind advocates, on the other hand, sometimes argue that the small size of a typical wind farm implies that its energy output will be largely invisible (and therefore cost free) to a large utility control area. Neither perspective is correct.

This project helps fill this data and analysis gap. Specifically, it develops and applies a quantitative method for the integration of a wind resource into a large electric system. The method permits wind to bid its output into a short-term forward market [specifically, an hour-ahead (HA) energy market] or to appear in real time (RT) and accept only intrahour and hourly imbalance payments for the unscheduled energy it delivers to the system. Finally, the method analyzes the short-term (minute-to-minute) variation in wind output to determine the regulation requirement the wind resource imposes on the electrical system.

This project focuses on the integration of wind with a competitive wholesale market overseen by a regional transmission organization (RTO).[#] Analysis of the integration of wind with a traditional, vertically integrated utility would, in some ways, be different from the present analysis. In particular, embedded costs would replace the market prices used in this project. Also, RTOs, by definition, have no stake in market outcomes. Because they own no

---

[*] Depending on government policies and fuel prices, wind might increase its share of total electricity production to 0.2% under business-as-usual conditions or to 1% or more by the year 2010 (Interlaboratory Working Group 2000). Caldwell (2001) and others expect wind might ultimately account for as much as 20% of U.S. generating capacity. de Azua (2001) expects the amount of wind capacity to increase from almost 2600 MW at the end of 2000 to about 4000 MW by the end of 2001.

[#] This study does not deal with all the issues relevant to integration of wind into bulk-power systems (Caldwell 2001). Transmission costs (access, losses, and congestion), day-ahead scheduling (unit commitment), and long-term contracting for the output from a wind farm are not addressed. Also, this project does not address contingency reserves. The reliability requirements for contingency reserves are based on either the maximum daily peak load or the largest single contingency. Because wind farms are relatively small (a few hundred megawatts, at most) and the largest contingency is typically about 1000 MW, wind should not be charged for contingency reserves because it does not contribute to the need for these reserves.

generation, they should be neutral with respect to the ownership and types of generating units that operate within their system. The same is not always true for utilities, which might favor their own generating units over those of their competitors.

The Utility Wind Interest Group (UWIG) is sponsoring a similar analysis, scheduled for completion in early 2002 (Zavadil 2001). The purpose of the UWIG study is to identify and quantify the effects of large wind facilities in the Great Plains and Pacific Northwest. The two control areas selected for study are operated by vertically integrated utilities. That is, competitive markets for HA and RT energy and for the regulation ancillary service do not exist in these areas. Therefore, the UWIG study will use simulation models to estimate the costs to the local utilities of integrating wind with respect to regulation, load following, and scheduling.

A key feature of the present analysis is its *integration* of wind with the overall electrical system. The uncontrollable, unpredictable, and variable nature of wind output is not analyzed in isolation. Rather, as is true for all loads and resources, the wind output is *aggregated* with all the other resources and loads to analyze the net effects of wind on the power system. Aggregation is a powerful mechanism used by the electricity industry to lower costs to all consumers.

The next section of this chapter explains the functions of control areas, specifically their efforts to maintain the necessary real-time balance between generation and load. The last part of this chapter outlines the technical scope of this project. Chapter 2 explains the kinds of data required to implement the analytical methods developed here. Chapter 3 summarizes data from the Lake Benton II wind farm in southwestern Minnesota and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the mid-Atlantic region, the empirical basis for the results developed here. Chapter 4 explains the method developed here. This method includes the use of short-term forecasting models to predict wind output two hours ahead, the separation of load and wind outputs into their regulation and energy-imbalance components, determination of the regulation requirements of the wind farm as a share of the total system requirements, and calculation of the intrahour payments and charges to a wind resource associated with its intrahour imbalances relative to its hour-ahead schedule. Chapter 5 presents results obtained with this method for 1-week periods in August 2000 and January 2001. Chapter 6 summarizes these results and their implications for greater use of wind in competitive wholesale electricity markets.

CONTROL AREAS

The electrical system with which the wind resource is integrated is called a control area. Control areas are the fundamental entities responsible for maintaining bulk-power reliability. Control areas are linked to one another to form Interconnections, of which there are three in North America.

Today's approximately 150 control areas are operated primarily by utilities, although a few are run by independent system operators (ISOs), including ones in California, Texas (the Electric Reliability Council of Texas, ERCOT), New England, New York, and the mid-Atlantic region (PJM). Control areas vary enormously in size, with several managing less than 100 MW of generation. At the other end of the spectrum, PJM, California, and ERCOT each manage about 50,000 MW of generation. In the future, RTOs, in response to Order 2000 and other directives from the Federal Energy Regulatory Commission (FERC 1999), will likely be control-area operators.

Although this project focuses on the near-real-time and real-time interactions of wind output and large electrical systems, it is important to consider the day-ahead scheduling (often called unit commitment) process as well. Some of today's ISOs (New England, New York, and PJM) offer a voluntary unit-commitment option to their market participants, in which the ISO selects the least-cost mix of generating units to operate hour-by-hour during the following day. Other ISOs (California and ERCOT) require the individual suppliers to perform this optimization function. In either case, the net result is an hour-by-hour schedule of output levels for each generator scheduled to run the following day. Because of changes that can occur between the time the day-ahead unit commitment is prepared and real time (e.g., the forced outage of a major generator or an unexpected change in weather that materially affects load), suppliers are permitted to modify their schedules up to about an hour before the operating hour.

In real time, the system operator dispatches resources participating in its intrahour energy market to maintain the necessary balance between generation and load (discussed below). 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 automatic-generation-control 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.

Thus, the system operator manages the relationship between system load and aggregate generation over three time scales: (1) day- and hour-ahead scheduling, (2) intrahour balancing, and (3) regulation. (See Hirst 2001 for additional discussion of these three sets of functions.) All three time scales are important for intermittent resources, such as wind. A key question is: How closely must the system operator match generation to load?

---

[*] PJM, New York, and New England use 5-minute intervals for their intrahour economic dispatch, California uses 10 minutes, and ERCOT uses 15 minutes.

Area control error (ACE) is the key to understanding this question. Each control area seeks to minimize any adverse effects it might have on other control areas within its Interconnection by properly managing its ACE (NERC 1999). The ACE equation, in slightly simplified form, is

$$ACE = (I_A - I_S) - 10\beta(F_A - F_S) \ ,$$

where I refers to the algebraic sum of all power (MW) flows on the tielines between a control area and its surrounding control areas, F is the Interconnection frequency (Hz), A is actual, S is scheduled, and β is the control area's frequency bias (MW/0.1Hz).[*] The first term shows how well the control area maintains its schedules with other control areas (i.e., how well it matches its generation plus net incoming scheduled flows to its loads). The second term is the individual control area's contribution to the Interconnection to maintain frequency at its scheduled value (usually 60 Hz). Thus, ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency.

NERC's Control Performance Standard (CPS) 1 and 2 determine the amount of imbalance that is permissible for reliability. CPS1 measures the relationship between the control area's ACE and Interconnection frequency on a 1-minute average basis (NERC 1999). 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, called L_{10}. 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 (10% of the 144 10-minute intervals), on average, during any month.

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.

The implications of these NERC requirements for a volatile resource, such as wind, are profound. For example, to meet the CPS requirements, the system operator need not acquire

---

[*] Frequency bias is the amount of generation needed to respond to a 0.1 Hz change in Interconnection frequency. It is usually set equal to the supply-plus-load response of a control area to a change in Interconnection frequency.

regulation and load-following resources to exactly counter each and every change in wind output. All the system operator need do, when unscheduled wind output appears on its system, is maintain its average CPS performance at the same level it would have without the wind resource.

PROJECT SCOPE

This project focuses on the RT operations and short-term functions and markets that exist (or might exist) in a competitive wholesale electricity industry. It focuses on three time dimensions of the wind output: scheduled hourly energy, intrahour load following, and regulation. (The terms load following and intrahour imbalance are used interchangeably.) Specifically, the method developed here analyzes the interactions between a wind farm and the control area in the following areas:

- Hour-ahead energy market, which provides the last (latest) opportunity for a generator (or load) to modify its schedule and obtain a firm price for that scheduled output (or consumption) for a particular operating hour. In the method developed here, this market permits the wind-farm operator to sell its expected output in hour *h* using a forecast of wind output based on its output two or more hours earlier.

- Real-time (intrahour) balancing market, in which unscheduled resources and loads appear. These unscheduled amounts are the differences between the actual resource or load and the HA scheduled values (i.e., $Q_t - Q_{h\text{-}sched}$), where *t* refers to a particular 5- or 10-minute interval within the operating hour and *h* is the operating hour.[*]

- Regulation, which charges the individual resource for the effects of its minute-to-minute volatility in output relative to the volatility of the total system load.

Regulation is the use of online generating units that are equipped with automatic-generation-control equipment and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for unintended fluctuations in generation (Hirst and Kirby 1998). In so doing, regulation helps to maintain Interconnection frequency, manage differences between actual and scheduled power flows among control areas,

---

[*] The hourly imbalance, the difference between the amount of electricity actually produced during the operating hour and the amount scheduled in the HA market, is settled at the hourly RT price. As discussed in Chapter 4, some system operators impose artificial penalties on hourly imbalances, often with no cost justification. Because the hourly RT price is based on the intrahour interval prices, this hourly imbalance payment or charge will be almost identical to the dollar amount obtained in the intrahour balancing market discussed in this bullet. The hourly price will, depending on the market rules, equal either the weighted (usually by the absolute values of the imbalance amounts during each interval) or the unweighted average of the interval prices. In PJM, the hourly price is the unweighted average of the 12 5-minute interval prices.

and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.

The system operator uses the RT balancing market to deploy generators providing the load-following service (Hirst and Kirby 1998).[*] Load following is the use of online generation equipment to track the intra- and interhour changes in customer loads and unscheduled changes in generator output. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation, five minutes or more rather than minute to minute. Second, the load-following patterns of individual customers are highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns; this phenomenon yields stable and predictable diurnal load shapes (see Figs. 4 and 5 in Chapter 3).

---

[*] FERC's (1996) Order 888, which defined six ancillary services, did not discuss load following. However, FERC's (1999) Order 2000 requires RTOs to operate RT (intrahour) balancing markets. The primary resource for these markets is generation that can change output every five or ten minutes to follow changes in system load.

DATA INPUTS

This chapter describes the data elements required to implement the method explained in Chapter 4. Data are needed for the control area as well as for the wind facility.

WIND RESOURCE

The only data on the wind farm required for this project is 1-minute average output (MW).[*] These data are then aggregated to the 5-minute and 1-hour levels for various analyses.

CONTROL AREA

This method requires detailed data from the control area within which the wind resource is electrically located. These data include variables collected and reported at the 1-minute, intrahour interval (5-, 10-, or 15-minute), and hourly levels.

Data required at the 1-minute level include averages[#] of ACE and system load (both in MW). [Data on Interconnection frequency (Hz), net interchange schedules and actual values (MW), and total generation (MW) are helpful because they can be used to check for data errors.] These data, along with the control-area values of β and L_{10}, permit calculation of hourly values of CPS1 and 2. They are also needed to calculate the control area's regulation requirement.

Data required at the interval level include incremental and decremental dispatch requests (MW) and the associated prices ($/MWh). PJM, unlike most control areas, does not dispatch generators directly (i.e., PJM does not order generators to move up or down a specified number of megawatts each interval). Rather, it uses a supply curve and sends price signals to all generators under PJM's dispatch control every minute. Figure 1 shows the PJM supply curves for each day during a week in August 2000. These supply curves are based on the prices and quantities bid by individual generating units into the PJM system. Essentially, PJM determines,

---

[*] Analysis of regulation performance for several control areas showed that generation typically follows load at about the 1-minute level (Hirst and Kirby 2000). Also, the NERC CPS1 calculation uses 1-minute averages.

[#] For certain variables, especially ACE, it is important to use 1-minute averages and not instantaneous (snapshot) values. The instantaneous difference between generation plus net schedules and load can be quite different from the average values.

every five minutes, how much more or less capacity is required relative to current conditions. It then reads the total amount [current output plus incremental (or minus decremental) energy] needed for the next interval on the *x* axis of Fig. 1, identifies the point on the supply curve directly above that quantity, and then distributes a price signal equal to the amount directly to the left of that point on the *y* axis. This price signal is sent to all generators participating in the PJM balancing market.

The daily PJM supply curve, which encompasses virtually all the generating capacity within the region, may not reflect accurately the capacity that can quickly ramp from one output level to another every five minutes. Many generators have slow ramp rates (measured in MW/minute) and therefore cannot participate in the intrahour energy market. It is also unclear whether the prices bid into this supply curve include the incremental costs to a generator of ramping up and down, relative to the costs of steady-state operation (Fig. 2).

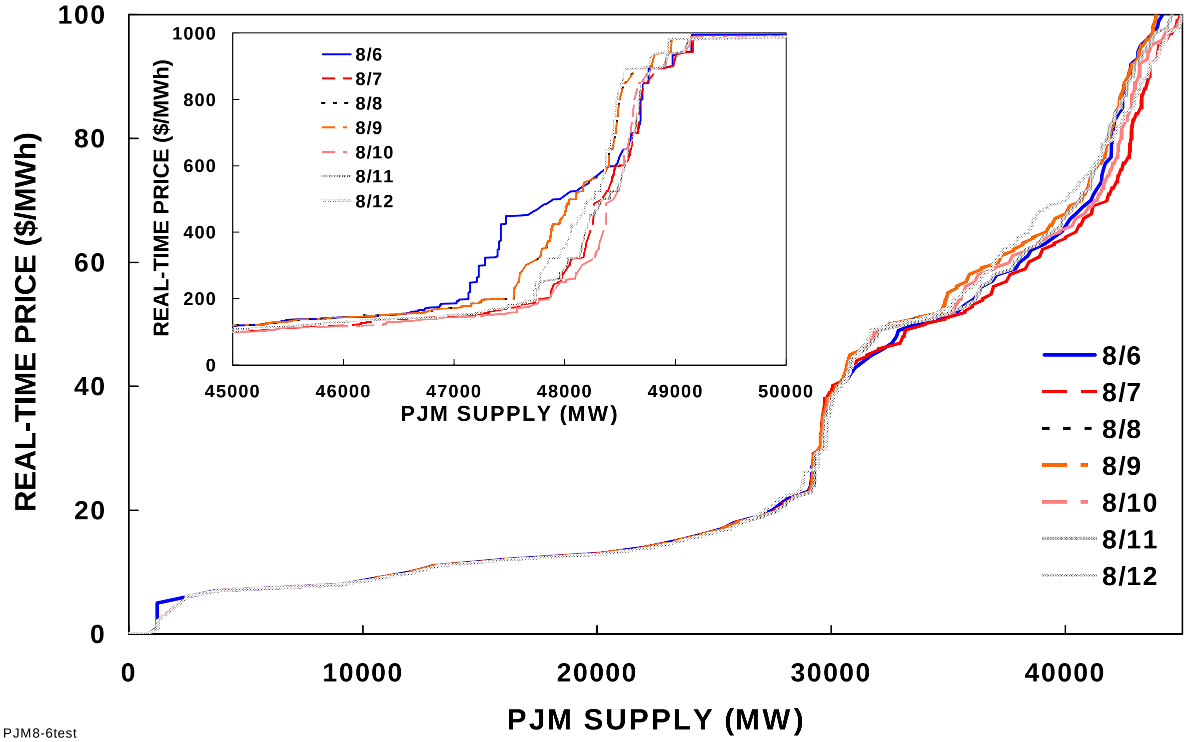


Fig. 1. **PJM supply curves for the week of August 6, 2000. These curves show the amounts of supply bid into PJM's intrahour energy market as a function of price. The inset, with different scales for the two axes, shows the supply curves at high levels of supply and prices.**

Data required at the hourly level include prices for energy in the HA and RT markets ($/MWh) as well as the price of the regulation service ($/MW-hr). (Energy prices are in $/MWh of energy, while ancillary-service prices are in $/MW-hr, where MW-hr refers to a MW of ancillary service provided for an hour.)

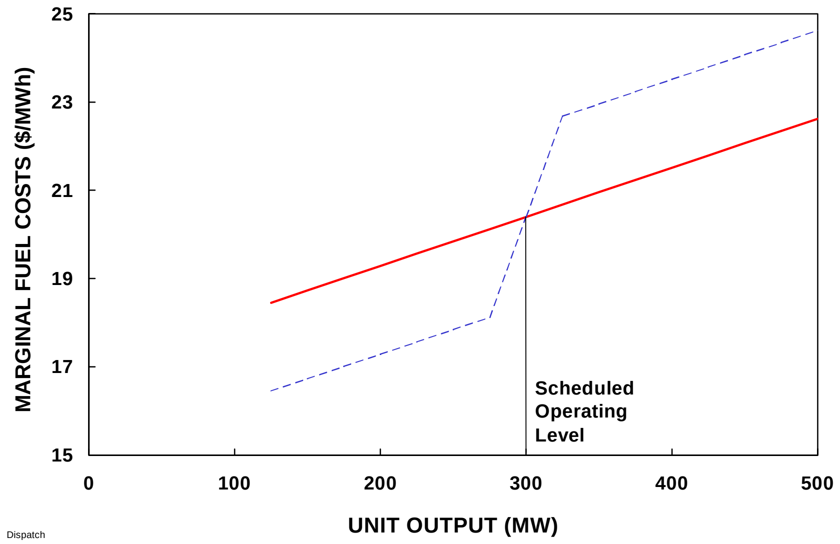


Fig. 2. **Hypothetical supply curves for a generator for hourly energy (solid line) and intrahour balancing (dashed line). The higher incremental and lower decremental costs for balancing energy reflect the presumed costs of ramping up or down.**

CHAPTER 3

LAKE BENTON AND PJM CHARACTERISTICS

This chapter summarizes the data used to develop and test the method discussed in Chapter 4. The wind data were obtained from the Lake Benton II wind farm. The control-area data were obtained from PJM. In essence, I assume in these analyses that the wind-farm output is dynamically scheduled from the local control area in Minnesota to the PJM system.[*]

In some ways, it might have been better to analyze data for a wind farm and the control area within which it is *physically* (as opposed to *electrically*) located. In such cases, the same weather would, presumably, drive wind output and system load. Analysis of such cases would show any benefits associated with positive correlations between wind output and system load. On the other hand, this project is intended to show how wind can be integrated with *competitive* wholesale markets, which eliminates control areas run by utilities. Competitive markets have been in operation for a year or more in only four parts of the country: New England, New York, PJM, and California. (The Texas market opened in late July 2001.) In addition, some of these markets, especially those in California, are undergoing rapid change and are seriously flawed. Finally, obtaining relevant and reliable data requires that the system operator maintain large and high-quality databases and that it has staff who are both knowledgeable about these data and able to take the time to collect and explain these data to others. I was fortunate and grateful to obtain two weeks of detailed data (one for summer 2000 and the other for winter 2000/2001) for use in this project.

LAKE BENTON WIND CHARACTERISTICS

The Lake Benton II wind facility is located in southwestern Minnesota. With 138 turbines, each with a rating of 0.750 MW, the rated (maximum) capability of the facility is 103.5 MW (Wan and Walsh 2000). The turbines are connected through four metering points at two 34.5-kV feeders to the transmission system of Northern States Power Company (now part of Xcel Energy).

During the 12-month period from July 2000 through June 2001, the average hourly output from this wind farm was 36 MW, equivalent to a 35% capacity factor. The average hourly output, however, varied substantially from month to month, from a low of 18 MW in

---

[*] Dynamic scheduling is the electronic transfer from one control area to another of the time-varying electricity consumption of a load or the time-varying electricity production of a generator (Hirst and Kirby 1997).

July 2000 to a high of 48 MW in April 2001 (Table 1). Perhaps more important from the perspective of this project, the range in hourly output was about 95 MW (Table 1 and top part of Fig. 3). The standard deviation of the hourly wind output is about 85% of the hourly output, suggesting substantial hour-to-hour variation in wind output.

The bottom part of Fig. 3 illustrates how wind output changes from hour to hour during a month, in this case October 2000. On average, the hour-to-hour change in output was 6 MW, ranging from 0 up to 50 MW.

As shown by the correlation coefficients[*] (*r*) in Table 1, the wind output is uncorrelated with either the Northern States Power system load or the PJM system load. This lack of correlation is important because hourly spot prices are typically highly correlated with system load. The correlation coefficient between the hourly wind output and the PJM system load was -0.4 for the week of August 6, 2000 and 0.0 for the week of January 15, 2001, the two weeks for which I received detailed data from PJM.

Table 1. Summary of hourly data on Lake Benton wind output for one year

	Average	Maximum[a]	Coefficient of variation[b]	Correlation coefficents[c]	
				NSP	PJM
Jul-00	18.2	86.6	1.2	-0.02	-0.12
Aug-00	25.0	87.1	0.9	-0.01	-0.14
Sep-00	34.8	94.4	0.9	0.06	-0.22
Oct-00	33.7	96.5	0.9	-0.01	-0.02
Nov-00	40.9	98.1	0.8	-0.04	-0.03
Dec-00	40.3	97.7	0.8	-0.02	0.01
Jan-01	46.3	99.2	0.8	0.11	0.14
Feb-01	43.7	97.1	0.7	-0.07	-0.01
Mar-01	35.6	98.0	0.9	-0.10	-0.14
Apr-01	47.5	95.8	0.7	-0.08	-0.10
May-01	36.5	94.5	0.8	0.12	0.11
Jun-01	36.3	92.1	0.9	0.16	0.01

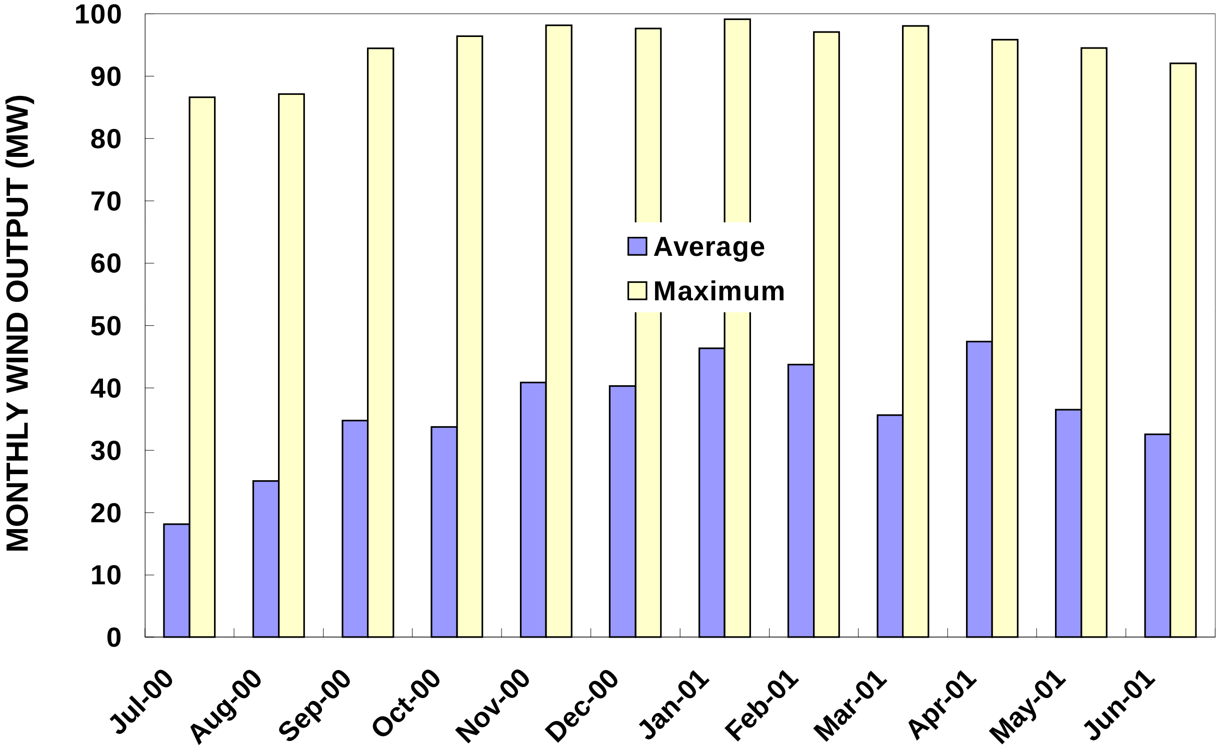
[a] The minimum value of hourly wind output was 0 MW each month.

[b] The coefficient of variation is equal to the ratio of the standard deviation to the mean.

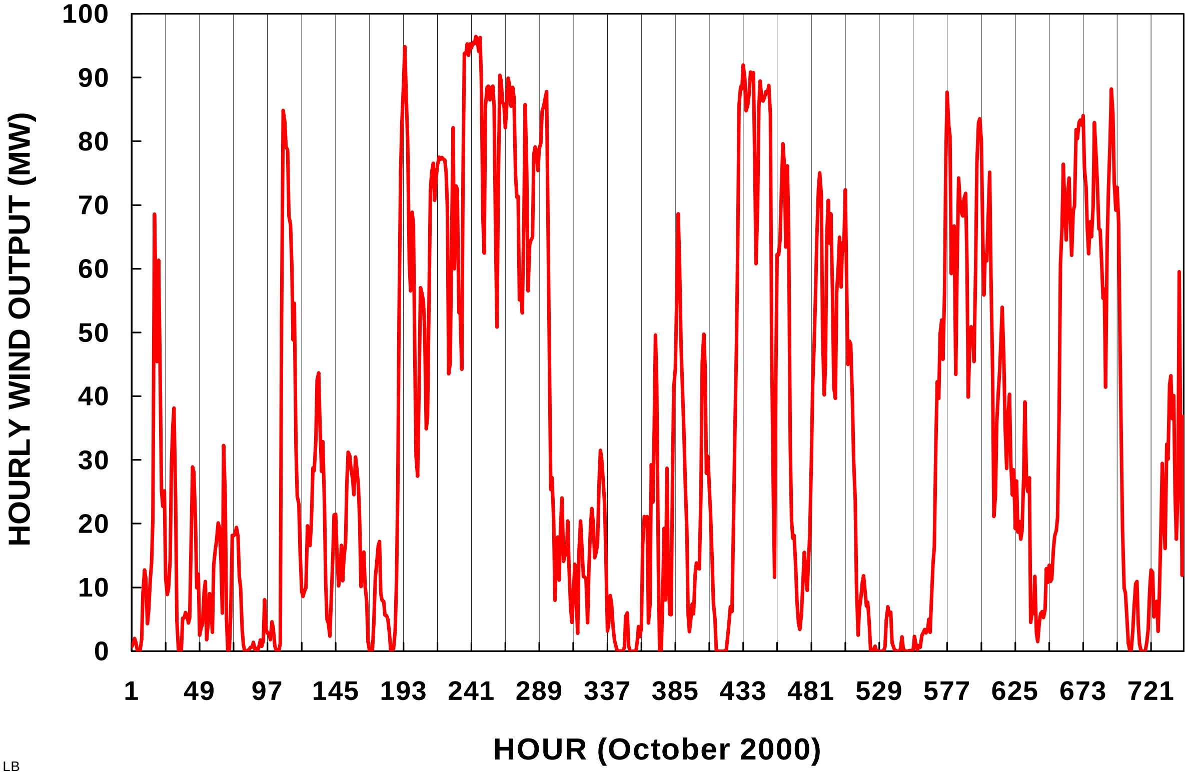
[c] The values in these two column are the correlation coefficients between the values of hourly wind output and hourly Northern States Power system load or PJM system load.

---

[*] The correlation coefficient measures how well variations in one variable predict variations in a second variable. The coefficient can range from +1 (perfect positive correlation) to 0 (no correlation at all) to −1 (perfect negative correlation).



LB



LB

Fig. 3. Summary of hourly data on wind output (MW) by month (top) and hour-by-hour for October 2000 (bottom).

Table 2 summarizes data on wind output for the two 1-week analysis periods used in this project. On average, the regulation component of wind output (measured by the standard deviation of the 1-minute fluctuations around the intrahour-imbalance component, as explained in Chapter 4) is about 2% of the average output. Regulation is a smaller share of wind output in January than in August. These data show large day-to-day variations in wind output and regulation requirements, especially for the week in August.

PJM CHARACTERISTICS

PJM is a large ISO, covering parts or all of five states (Pennsylvania, New Jersey, Maryland, Virginia, and Delaware) plus the District of Columbia. The PJM peak load is about 52,000 MW. PJM operates day-ahead (DA) markets for energy and regulation as well as an RT market for energy.

During the week of August 6, 2000, the PJM load averaged almost 36,000 MW, 12% higher than during the week of January 15, 2001 (Table 3). Thus, the wind output averaged 0.06% of the PJM load in August 2000 and 0.12% in January 2001.

Table 2. Summary of data on hourly wind output for August 2000 and January 2001

	Week of August 6, 2000		Week of January 15, 2001	
	Output (MW)	Regulation as % of output[a]	Output (MW)	Regulation as % of output[a]
Weekly results				
Average	22	2.4	38	1.4
Maximum	87	13.4	96	7.4
Minimum	0	0.5	0	0.0
Standard deviation	25	1.7	32	1.1
Daily averages				
Day 1	18	2.8	16	1.9
Day 2	5	3.5	7	2.2
Day 3	8	2.9	54	1.0
Day 4	2	2.2	59	1.0
Day 5	19	2.1	39	1.4
Day 6	56	1.2	59	1.0
Day 7	44	2.1	30	1.4

[a] These regulation values are based solely on the fluctuations in wind output and do not account for the interaction of wind with system load (as explained in Chapter 4). These values are calculated only for hours when wind output is greater than 2 MW because the values are unstable when wind output is very low.

The PJM load is, on an hour-by-hour basis, reasonably predictable. As shown in Fig. 4, loads follow a consistent daily pattern, with lower loads on the two weekend days. Although the winter load shape is different, it too has a consistent pattern from day to day. Figure 5 compares the hour-by-hour shapes for the wind-farm output and the PJM system load for the five weekdays during this period in August 2000. Clearly, system load is a strong function of the hour of the day, whereas wind output is largely independent of the hour of the day.[*] On the other hand, this comparison may be unfair to the wind farm, which includes 138 turbines, compared to the PJM system load, which includes several million customers.

The regulation component of the PJM load is about 0.1% of the total load, slightly higher in January 2001 than in August 2000 (Table 3). PJM customers paid the equivalent of \$0.68/MWh of energy for regulation in August and \$0.50/MWh in January.

Table 3. Summary of data on PJM hourly loads and market prices for August 2000 and January 2001

	Week of August 6, 2000					Week of January 15, 2001				
	Load (MW)	Regulation as % of output	Hourly market prices ($/MW)			Load (MW)	Regulation as % of output	Hourly market prices ($/MW)		
			DA energy	RT energy	Regulation			DA energy	RT energy	Regulation
Weekly results										
Average	35,982	0.09	44.9	39.4	53.3	32,064	0.12	31.9	31	41.9
Maximum	49,300	1.02	140.0	136.6	125.8	38,367	0.49	68.2	126.5	116.3
Minimum	21,397	0.04	11.4	0.0	19.5	24,756	0.06	15.0	12.7	22.6
Standard deviation	7,866	0.10	32.4	26.5	27.7	3,770	0.04	11.2	20.2	14.3
Daily averages										
Day 1	27,380	0.08	25.3	15.5	31.3	31,633	0.12	34.4	26.9	45.7
Day 2	38,568	0.14	48.9	54.5	52.8	32,202	0.15	29.6	21.6	34.5
Day 3	40,185	0.08	72.1	42.9	82.7	32,701	0.11	32.2	28.6	39.4
Day 4	40,805	0.09	67.0	47.2	67.1	33,373	0.12	31.6	40.5	47.8
Day 5	39,255	0.08	46.8	49.0	61.4	32,567	0.11	30.5	36.4	44.4
Day 6	36,438	0.09	35.9	42.8	42.8	30,934	0.10	33.4	35.1	43.9
Day 7	29,242	0.08	18.1	24.1	35.0	31,037	0.10	31.4	28.0	37.7

---

[*] Statistical analysis of system load and wind output for each of the 24 hours for each month confirms the results of Fig. 5. The coefficient of variation for each hour and month (288 observations) for the wind output is typically nine times higher than that for the PJM system load.

Energy prices are generally, but not always, higher on the weekdays. DA prices are 14% higher than RT prices in August and 3% higher in January.* RT prices were zero for three hours early on Sunday, August 6 (top of Fig. 4). Although the daily load shapes and levels were quite consistent for the week in January, the prices differed substantially from day to day; in particular, prices spiked on Saturday, January 20. Finally, regulation prices are consistently higher than energy prices (Table 3).

System load and RT prices are highly correlated for the summer period (0.88) and modestly correlated for the winter week (0.55); see Fig. 4.

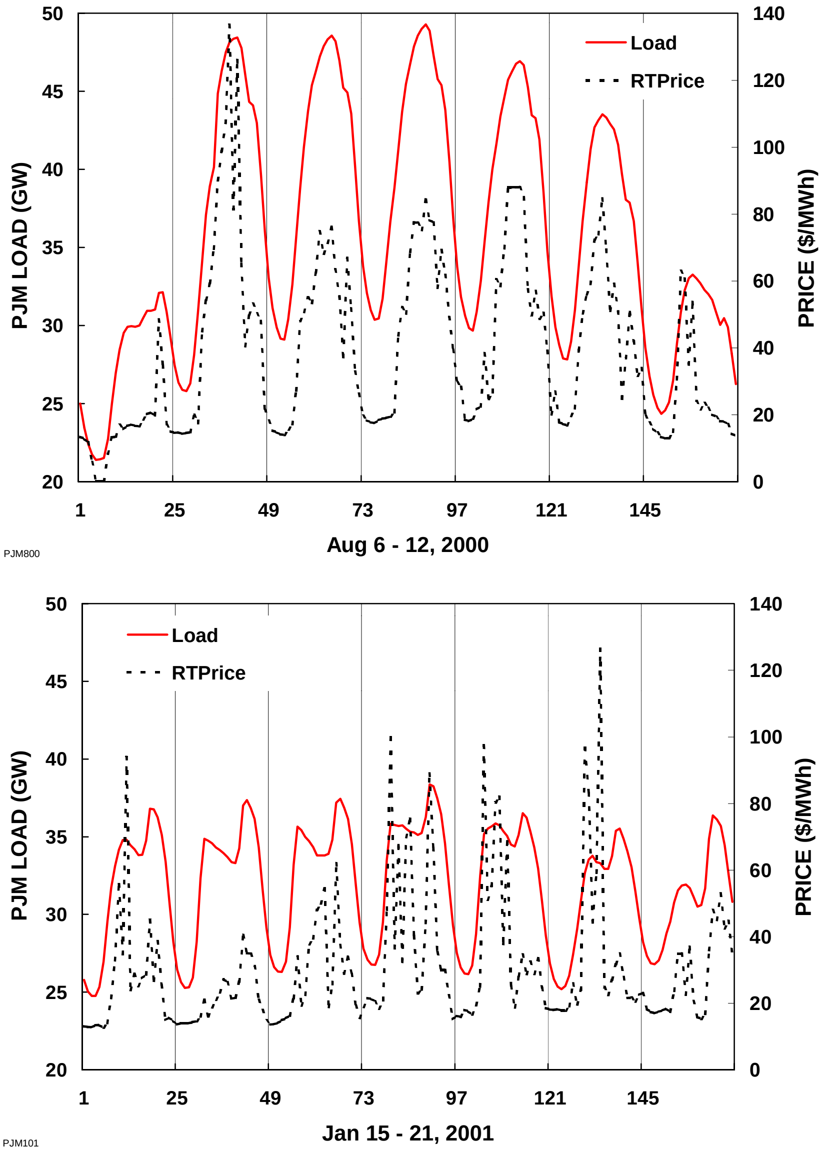


Fig. 4. **PJM hourly load and real-time prices for the weeks of August 6, 2000 (top) and January 15, 2001 (bottom).**

PJM dispatches generators every five minutes to maintain the necessary generation-load balance and to return the units providing the regulation service to their base points. The top of Fig. 6 shows a sample of the 5-minute prices for one day in August 2000. For the first several hours (through about 7 am), the interval prices change only slowly. However, during the middle of the day, the prices

---

*The discussion of the costs of ramping units up and down during the hour (Fig. 2, page 11) suggests that RT prices should be higher than DA prices, the opposite of what the PJM data show. On the other hand, DA prices might be higher than RT prices if consumers and/or suppliers are risk averse (see Chapter 3 of Hirst 2001).

change rapidly, not just from hour to hour but also within hours. The average of the absolute values of the associated 5-minute imbalance amounts is almost 1000 MW (bottom of Fig. 6).[*]

PJM's CPS performance far exceeded the NERC requirements. Specifically, CPS1 averaged 169% for the week in August and 168% for the week in January, well above the NERC requirement of 100% on an annual basis. Similarly, CPS2 averaged 96% for the week in August and 97% for the week in January, well above the NERC requirement of 90% on a monthly basis.

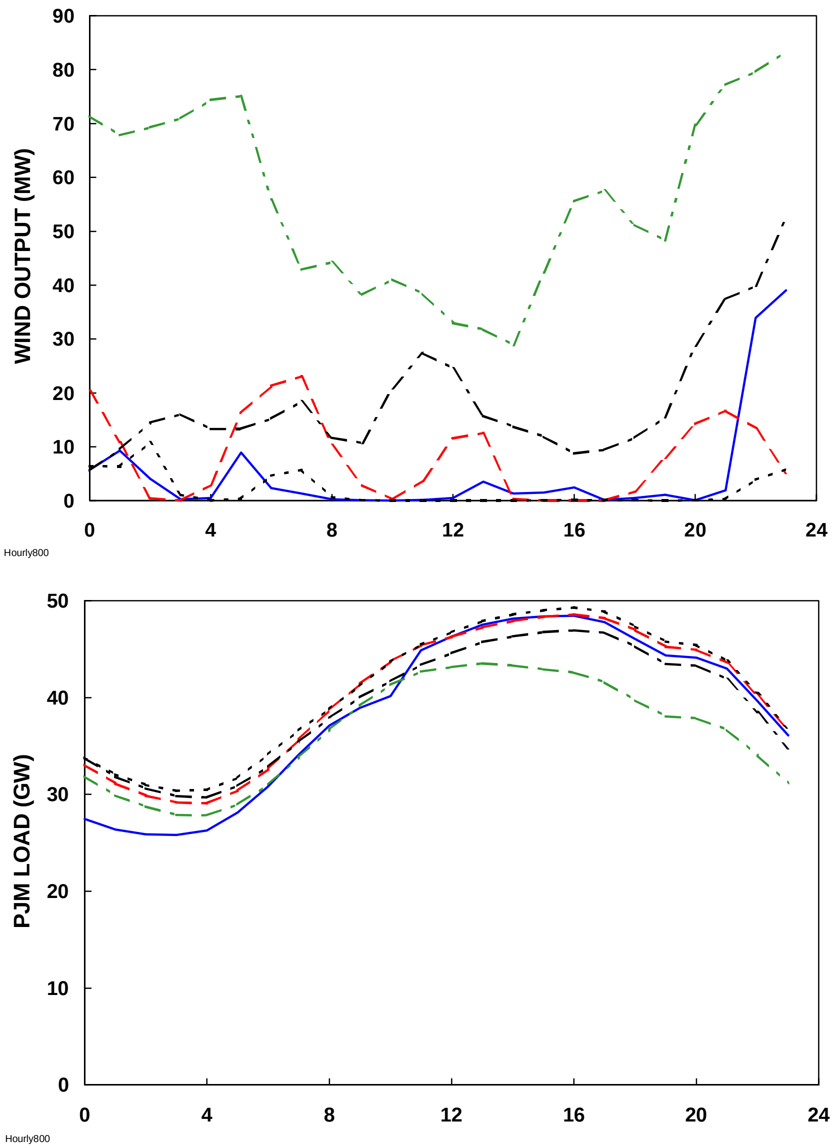


Fig. 5. Hourly wind output for five consecutive weekdays in August 2000 (top) and PJM system load for the same days (bottom).

---

[*] I was unable to obtain from PJM data on the hour-ahead generation schedules; thus, the imbalance amounts shown in Fig. 6 assume that the hourly average imbalance is zero.

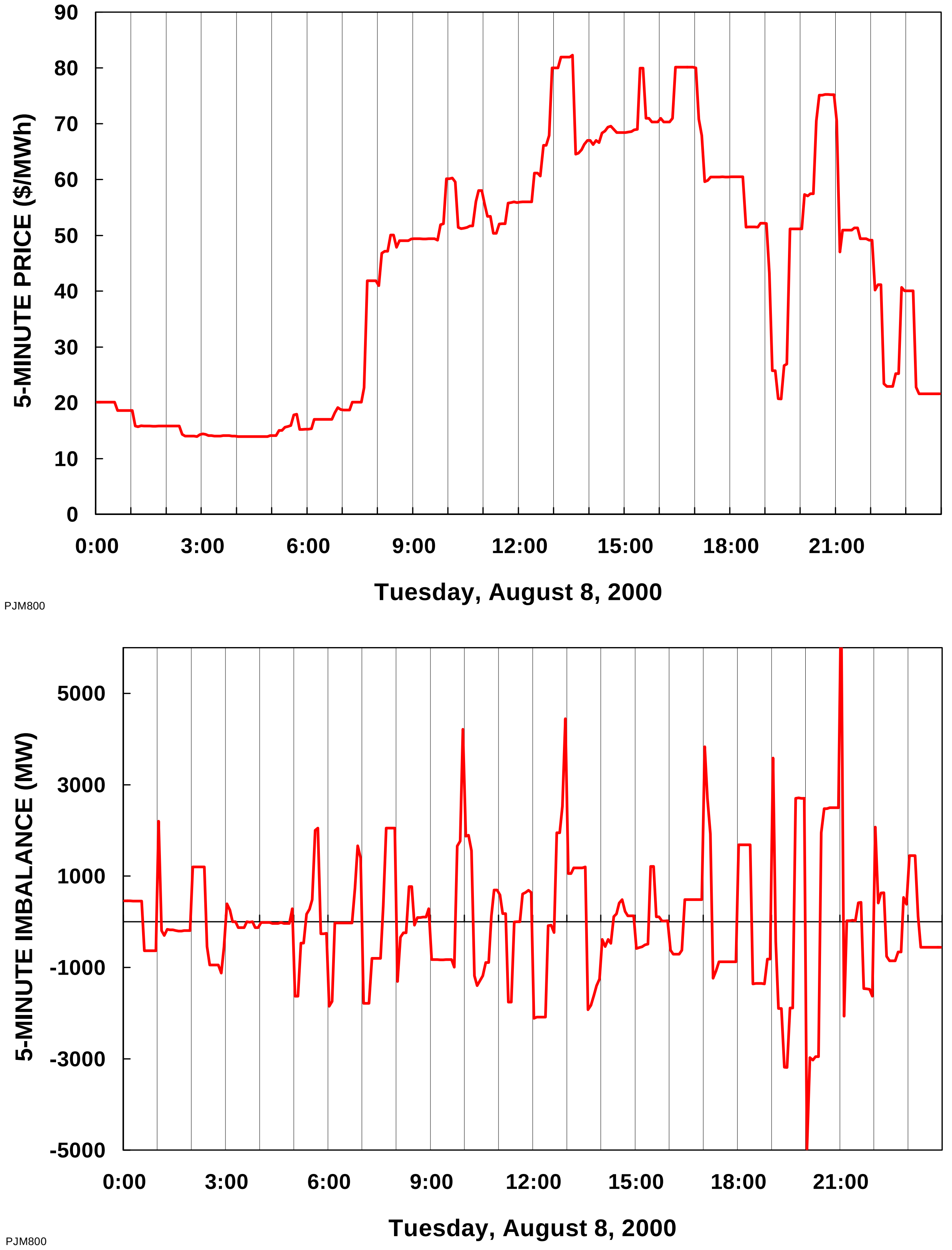


Fig. 6. PJM interval prices (top) and imbalance amounts (bottom) for one day.

CHAPTER 4

ANALYTICAL APPROACH

The method explained below estimates the major economic effects of wind facilities on a bulk-power system by calculating the payments the wind owner would receive for the energy delivered to a control area as well as the payments the wind owner would have to make for the regulation service and any energy-imbalance charges. The method requires data from a control area on both operations and markets as well as 1-minute data on wind output. The method involves forecasting wind output an hour or more before the operating hour, splitting the 1-minute system load and wind output into their regulation and intrahour-imbalance components, allocating the appropriate regulation costs to wind, calculating the intrahour imbalance payments and charges for wind, defining and testing bidding strategies for the wind resource, and calculating total payments and charges for the wind farm.

FORECASTING WIND OUTPUT

Meteorological models (using weather data from satellites and surface measurements) can be used to produce hourly wind forecasts for the next one to two days (Milligan 2001). Because this project focuses on the short-term interactions between a wind farm and its control area, I did not consider these models. Instead, I focused on models that predict the output of a wind farm two hours ahead, called persistence modeling. I focus on two hours ahead, rather than one hour ahead, because most competitive wholesale markets require that operating schedules be finalized 30 to 60 minutes before the operating hour begins.*

I developed a model to predict hourly wind output for the months that included the data from PJM, August 2000 and January 2001. For August 2000, actual hourly output ranged from 0 to 87 MW, with an average of 25 MW. The model explained 81% of the hourly variation in wind output as a function of two variables, both of which are statistically significant at the 1% level: (1) the wind output two hours before and (2) the difference between the output two and three hours before:

$$MW_{predicted} = 2.68 + 0.891 \times MW_{-2} + 0.970 \times (MW_{-2} - MW_{-3}) \ .$$

---

*The planned Southwest Power Pool (2001) HA market ends “30 minutes prior to the start of the Operating Hour.” ERCOT’s (2001) adjustment period ends 60 minutes before the start of the operating hour. PJM permits schedule changes up to 20 minutes before the start of the hour. In California, supplemental energy bids are accepted until 45 minutes before the operating hour, although scheduling changes must be made at least two hours ahead of time.

The model coefficients show that the output of a wind farm depends strongly on the outputs two and three hours before. Figure 7 shows the actual and predicted values for all 744 hours of the month. The forecast has an error that ranges from an overprediction of 37 MW to an underprediction of 51 MW. The standard deviation of the hourly forecast error is 9.5 MW.

This forecast is used in the present analysis to establish the amount of energy the wind operator bids into the RTO's HA energy market. This schedule is financially firm, which means that the wind farm will receive revenues equal to its *scheduled* output times the HA energy price. Any difference (imbalance) between the *actual* and *scheduled* wind output during the operating hour will be settled at the hourly RT price. I also conduct a sensitivity analysis to estimate the potential benefits of more-accurate forecasts of hourly wind output.

SPLITTING REGULATION FROM INTRAHOUR IMBALANCE

As noted above, regulation is the ancillary service that adjusts for short-term volatility (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.

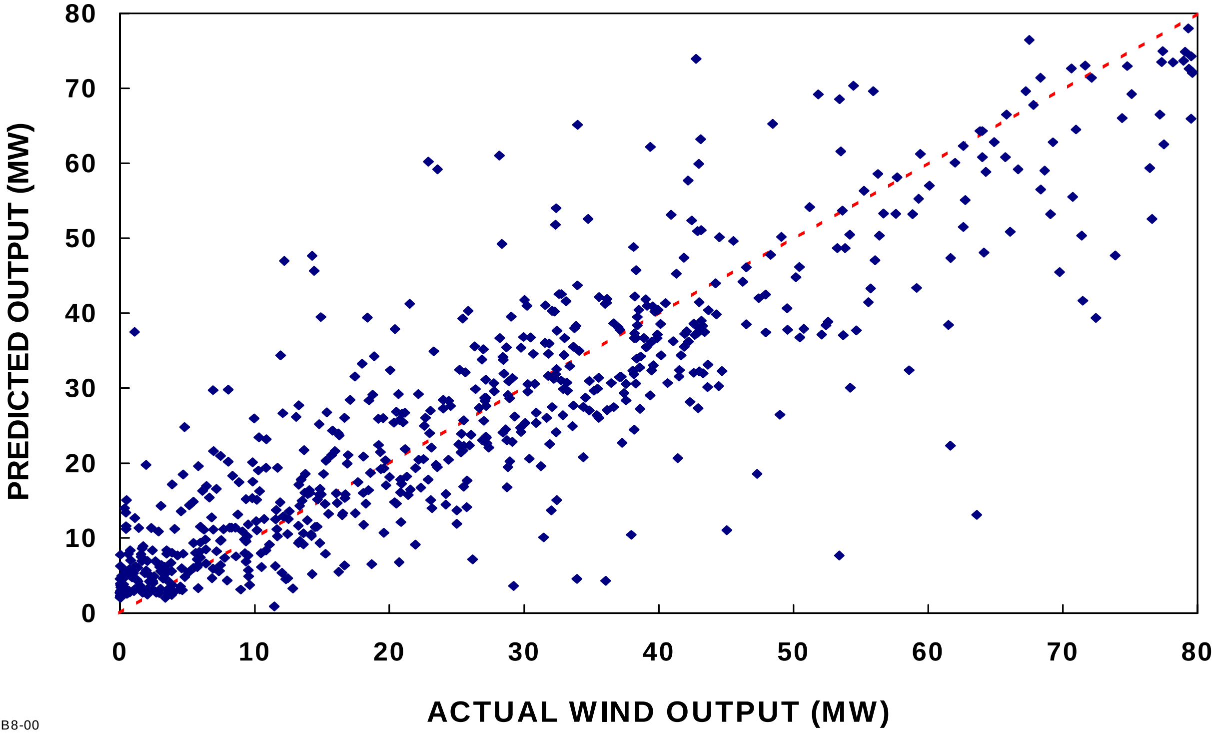


Fig. 7. **Hourly predicted vs actual wind output for August 2000. The predicted and actual values are equal along the dotted line.**

In a prior project, Kirby and Hirst (2000) used a 30-minute rolling average to define the boundary between the two services. We calculated the rolling average of, for example, system load, for each 1-minute interval as the mean value of the 15 earlier values of load, the current value, and the subsequent 14 values:

$$\text{Intrahour Imbalance}_t = \text{Load}_{\text{estimated-}t} = \text{Mean}\,(L_{t-15} + L_{t-14} + \ldots + L_t + L_{t+1} + \ldots + L_{t+14})\ ,$$

$$\text{Regulation}_t = \text{Load}_t - \text{Intrahour Imbalance}_{\text{estimated-}t}\ .$$

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. For the PJM system, intrahour balancing is a 5-minute service. Therefore, 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, as above, is the difference between actual load each minute and the imbalance component for that minute.

Figure 8 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 39 MW, with minimum and maximum values of 30 and 44 MW, respectively. The regulation value, by definition, averages zero for the hour, with minimum and maximum values of -2.4 and +1.8 MW. Because the imbalance interval is so short (five minutes), this component follows the raw data closely, and the regulation component is small.

This method allocates variability in load or generation between regulation and intrahour imbalance using historical data. In practice, system operators cannot know exactly the future movements of loads and generation. Although they use sophisticated short-term forecasting methods to guide their intrahour balancing and economic-dispatch decisions, those forecasts, and therefore the dispatch decisions, are often imperfect. Discrepancies between actual and forecast MW movements are addressed by the regulation service. Thus, the present method assigns too much of the wind and load variability to intrahour balancing and not enough to regulation. This misallocation between the two services has little or no effect on the results developed here, however, because the results are based on actual PJM performance (i.e., the amounts of regulation and intrahour balancing actually deployed hour-by-hour by PJM).

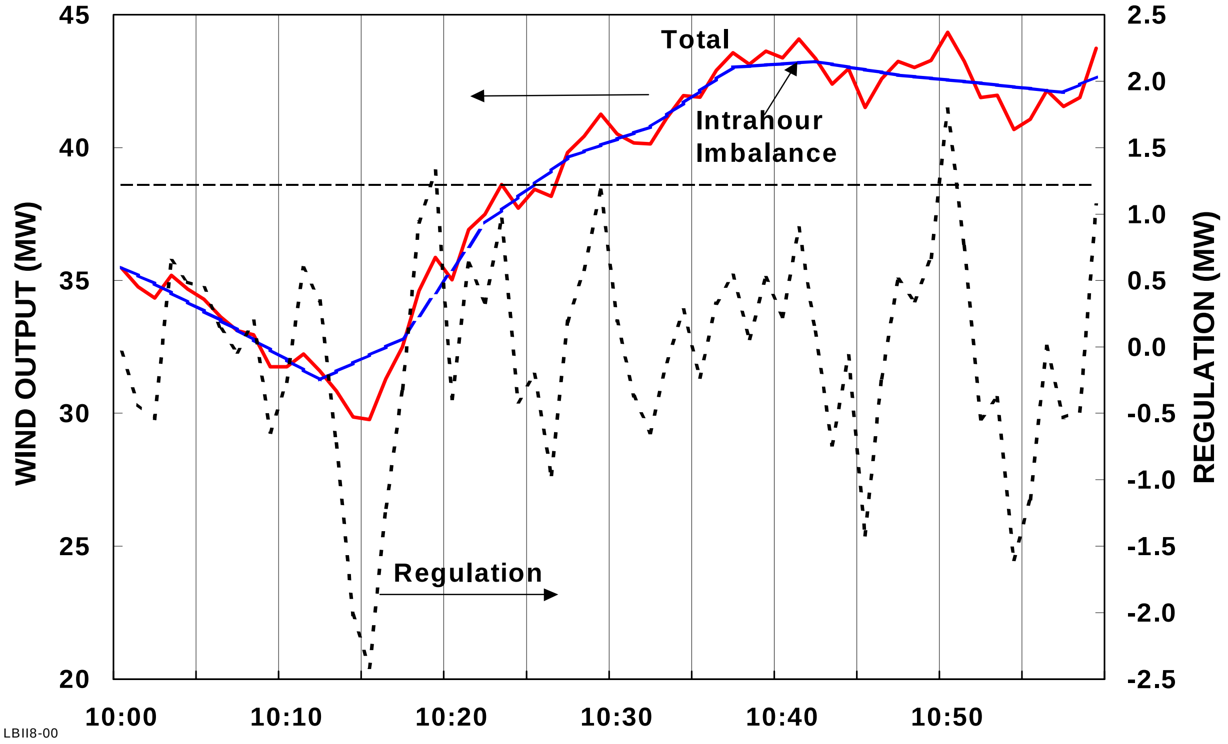


Fig. 8. **Minute-by-minute wind output (total and the intrahour-imbalance and regulation components) for one hour in August 2000.**

ALLOCATION OF REGULATION REQUIREMENT

I used the same method to disaggregate the 1-minute data on system load that I used with the wind data (discussed above). I next calculated the total regulation requirement and the wind share of that total using the method developed by Kirby and Hirst (2000). The method uses the standard deviation (σ, in MW) of the 1-minute regulation values (e.g., the dotted line in Fig. 8) to define hourly regulation requirements.

Regulation reflects the small, minute-to-minute fluctuations in load or output around a longer-term average. In principle, the individual regulation components of various loads and generators are likely to be largely uncorrelated with each other. In practice, the individual components of the regulation total may show some correlation, either positive or negative, with each other.

Figure 9 illustrates the method we developed for such allocations. This method works for all situations, regardless of whether the regulation components are positively correlated, uncorrelated, or negatively correlated. In addition, if a generator or load has a regulation component that is negatively correlated with the total (i.e., its random fluctuations reduce the overall regulation requirement), this method assigns a credit to that generator or load, in essence paying it for providing a valuable service to the electrical system.

Consider two regulation components (generators or loads) *A* and *B* and the *Total*, with the regulation requirement of each based on the standard deviation of the short-term fluctuations. We used a geometric approach to calculate the contribution of *A* to the *Total* (shown as *X* in Fig. 9), based on the relationship between *A* and the *Total*:

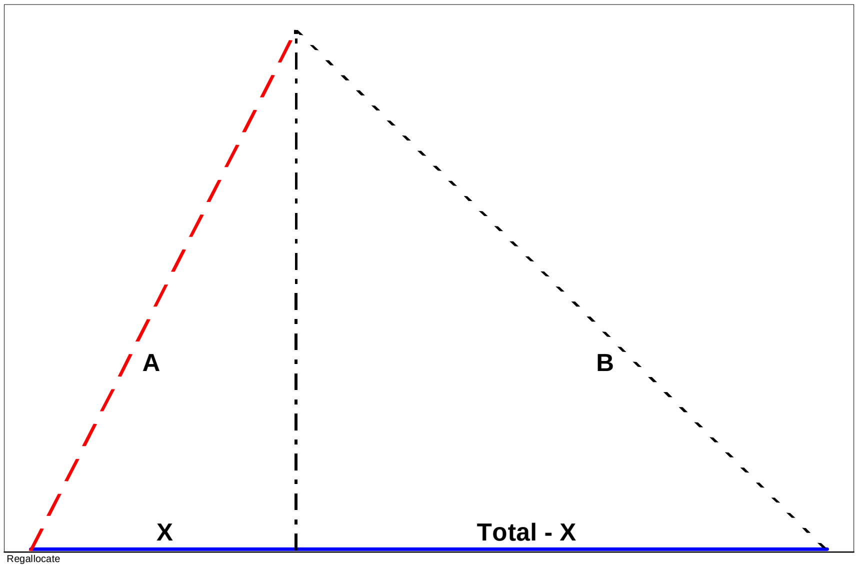


Fig. 9. Geometric allocation of individual components of regulation *A* and *B* to regulation *Total*. *X* is *A*'s share of the total. *B*'s share is *Total* − *X*.

$$X = (Total^2 + A^2 - B^2)/(2 \times Total) \ .$$

The contribution of *B* to the *Total* is then equal to *Total* − *X* or

$$Total - X = (Total^2 + B^2 - A^2)/(2 \times Total) \ .$$

The only computational requirement for this method is to calculate the standard deviations of each component and of each subtotal (*Total* minus individual load or generator).

The primary value of this process is that it calculates the hourly regulation requirement of the wind resource, not in isolation, but as a component of the total system requirement. Thus, the method treats wind exactly the same way a system operator should treat all generators and loads—as a contributor to the system's overall requirement.[*] The result of this process is a set of hourly regulation values for the wind resource. And, as noted above, these hourly values might sometimes be negative, suggesting a payment *from* the system operator rather than a payment *to* the system operator.

---

[*] Current ISO practice charges all loads for regulation on the basis of hourly energy use, with no regard for the contribution of each load's volatility to system regulation requirements. In addition, generators, some of which might have undispatched outputs that vary from minute to minute, are not charged for regulation at all.

INTRAHOUR BALANCING

The system operator uses the load-following resources and the intrahour energy market to (1) match generation to load at the lowest possible operating cost (as reflected by the incremental and decremental energy bids from individual generators) and (2) return the generators providing the regulation service to the midpoints of their operating ranges. In the following discussion, I assume that the regulation and intrahour balancing functions can be kept separate; the 5-minute imbalances are addressed in PJM's RT market, and the 1-minute fluctuations around the 5-minute imbalance amounts are addressed by the regulation service.

The control-area data include imbalance amounts (incremental or decremental capacity movements in MW) and prices* (in $/MWh) for each interval of the hour. In addition, these data show the supply curve for intrahour imbalance energy (Fig. 1, page 10).

Wind appears in the real-time market as the difference between its hour-ahead schedule and the actual wind output:

$$\mathrm{Wind}_t = \mathrm{Wind}_{\mathrm{actual}} - \mathrm{Wind}_{\mathrm{schedule}} \ ,$$

where t is a particular 5-minute interval and the schedule is a fixed amount throughout the hour, as specified by the wind owner, presumably based on its forecast of wind output.

The key question concerns what, if anything, the control area does with this additional source of imbalance. At one extreme, the system operator could ignore the effects of the intermittent wind output (Wind_t) and dispatch the intrahour generation resources exactly as it would have without the wind output. This case favors wind because it exempts wind from any imbalance costs. But, this approach would degrade the control area's reliability performance.

At the other extreme, the system operator could compensate fully for all variations in wind output. In this case, the system operator would dispatch other generation resources in exactly the same amounts and in the opposite direction from wind. This case unfairly penalizes wind by requiring it to maintain a *perfect* balance at all times between its actual and scheduled output, unlike other resources, which in *aggregate* (not *individually*) are required only to maintain an *adequate* balance, one that meets the NERC CPS1 and 2 requirements.

The method developed here requires the system operator to deploy its regulation and intrahour-imbalance resources to maintain roughly the same CPS1 and 2 performance levels with wind as it did without wind. I adjusted the imbalance requirements as follows to maintain the same levels of performance for the week:

---

*As discussed earlier, these intrahour prices should reflect both the value of the energy and the cost of moving a unit from one output level to another (expressed in MW/minute). It is not clear whether any ISO system now in operation accounts for this second factor.

$$\text{Imbalance adjustment}_t\ (\text{MW}) = -a[b \times \text{Wind}_{t-1} + (1 - b) \times \text{Wind}_t]\ ,$$

where a and b are user inputs that can range from 0 to 1. If a is set to 0, there is no adjustment, which defaults to the first case noted above. If a is 1, the adjustment is 100%, which defaults to the second case noted above. (If the output of the generator in question is extremely volatile, it might be necessary to set a greater than 1 to maintain CPS performance.) If b is 1, the adjustment occurs entirely in the subsequent interval. If b is 0, the adjustment occurs entirely in the same interval in which the imbalance occurs, which seems unrealistic. In principle, some of the imbalance adjustment could occur in later intervals. In the cases discussed below, I set b to 1 and varied a between 0 and 1 to maintain the without-wind CPS values. The adjustment has a negative sign because it involves movement opposite that of the wind resource itself.

The imbalance adjustment thus calculated is added to the original imbalance amount. This change may lead to a change in the imbalance price as PJM moves up and down the supply curve (Fig. 1, page 10). Therefore, a new price is calculated to correspond to the new imbalance requirement for each interval. The wind resource is paid (pays) for its incremental (decremental) imbalance energy at this new imbalance price. The payments (charges) for the 12 intervals in each hour are summed to obtain the hourly payment (charge) for the wind's hourly imbalance. Table 4 shows imbalance amounts and prices for two hours, with and without wind. The results for these two hours show that, on average, the imbalance price declines by about $1/MWh for every 100-MW increase in wind imbalance.

The approach described above treats wind fairly. That is, wind faces the same market that other resources do, and its revenues and charges are based on the costs the system operator faces.

On the other hand, some of the tariffs filed by utilities with FERC in response to Order 888 do not, in my view, treat imbalances fairly. For example, some energy-imbalance schedules permit the utility to keep any overgeneration without paying the supplier; similarly, some tariffs impose a penalty for undergeneration. The New York ISO (2001) tariff contains penalties, although they were never implemented, and the ISO recently sought permission from FERC to drop them. The New York tariff pays nothing for overgeneration (unlike PJM, which pays the current market-clearing price for energy). And, the New York tariff imposes a regulation surcharge for undergeneration (unlike PJM, which charges the current market-clearing price for energy).[*] To capture the effects of possible penalties in a system's intrahour imbalance market, I added a factor that imposes a specific percentage surcharge for undergeneration and the same percentage subtraction from payments for overgeneration.

---

[*] ERCOT (2001) imposes penalties on resources participating in its imbalance-energy market that deliver an amount of energy different from the scheduled energy for that interval (15 minutes) by more than 1.5% of the schedule or 5 MW, whichever is larger. However, "uncontrollable renewable resources" are not subject to this uninstructed-deviation penalty so long as their actual output each interval differs from their schedule by no more than 50%.

Table 4. Characteristics of PJM intrahour imbalance market without wind and for the wind output (at ten times actual) on August 8, 2000

Time	Imbalance (MW)		Imbalance price ($/MWh)	
	PJM without wind	Wind output[a]	PJM without wind	With wind
6:00	-1,848	64	15.2	15.2
6:05	-1742	63	15.3	15.3
6:10	-29	61	17.0	15.9
6:15	-29	67	17.0	16.0
6:20	-29	71	17.0	15.9
6:25	-29	84	17.0	15.9
6:30	-29	90	17.0	15.9
6:35	-29	86	17.0	15.9
6:40	-29	90	17.0	15.9
6:45	741	92	18.2	18.1
6:50	1663	93	19.1	18.0
6:55	1391	96	18.8	18.7
7:00	-1784	-11	18.7	18.6
7:05	-1784	-15	18.7	18.7
7:10	-1784	-19	18.7	18.7
7:15	-799	-17	20.1	20.2
7:20	-799	-13	20.1	20.2
7:25	-803	-15	20.1	20.1
7:30	-803	-22	20.1	20.2
7:35	341	-24	22.7	22.7
7:40	2054	-11	41.9	43.6
7:45	2054	0	41.9	42.0
7:50	2,054	-1	41.9	41.9
7:55	2,054	-12	41.9	41.9

[a] This column shows the wind imbalance alone, not the PJM imbalance with wind.

Even if a system operator imposes no artificial penalties on resources that do not follow their schedules closely, the market design and implementation could adversely affect resources that have intrahour imbalances. The California ISO's Balancing Energy and Ex Post Pricing system, which dispatches resources and sets prices every 10 minutes, is, unfortunately, a good example of such a system. The California system has separate incremental and decremental prices, both of which are in effect during some intervals. In addition, the ISO's rules prohibit it from clearing the market (i.e., the ISO is not allowed to match the decremental bids to buy that are above the incremental offers to sell). For the first seven months of 2001, the decremental prices were, on average, higher than the incremental prices! During this period, the imbalance prices were negative for about 5% of the time and zero about 25% of the time. (By comparison, PJM's imbalance prices were never negative and were zero less than 1% of the time from July 2000 through June 2001.) The consequences of California's irrational prices for a wind farm are substantial. Given these California prices, a wind farm would receive no payment at all for about one-fourth of the wind output and would be charged for about 5% of its output. The California ISO is working on these problems (Abernathy and Leuze 2001).

Wind, merely because its output is variable, should not be financially penalized. However, system operators might pay more for *instructed* deviations (generator movements up and down in response to specific system-operator requests) than for *uninstructed* deviations (generator movements independent of operator requests). The response to system-operator requests incurs additional fuel and maintenance costs because of the nonsteady-state operation of the unit as it ramps up and down, relative to steady-state operation. Because of these extra costs, the payments (charges) for instructed incremental (decremental) movements should be greater (less) than for uninstructed deviations (Fig. 2, page 11). For example, the California ISO pays for uninstructed incremental energy at the current decremental price and charges for uninstructed decremental energy at the incremental price. Only those resources participating in the imbalance market and responding accurately to dispatch instructions should be permitted to set the market-clearing price; other resources (including wind) should be price takers.

BIDDING STRATEGIES

The method developed here permits a wind resource to participate in wholesale electricity markets in one of two ways:

- The simplest strategy is for the wind farm to provide no advance schedules to the system operator and merely show up in real time. This strategy makes sense if the wind owner is unable to develop even a rudimentary method to forecast future wind output.

- A more refined strategy is for the wind owner to schedule the wind output an hour ahead of real time. The basis for this HA schedule would be a short-term forecasting model, perhaps along the lines of that discussed above. The difference between actual wind output and the HA schedule would be managed in the system operator's RT market at the intrahour price.[*]

In both cases, the wind resource would be charged for the regulation service it consumes on the basis of its minute-to-minute volatility around its intrahour-imbalance component. That is, the

---

[*] This method does not account for the effects on HA prices that the introduction of additional resources would have. In particular, when wind bids into the HA market, its participation will lower the HA price, reducing its HA revenues. This phenomenon is similar to what occurs in the RT market (which *is* accounted for in this method). The magnitude of this effect is likely to be much smaller in the HA market because more resources can participate in the HA market than can participate in the RT market because of ramp-rate restrictions and costs.

charges (and occasional payments for) regulation are independent of the wind's bidding strategy.

OTHER PARAMETERS

This method also permits the analyst to test various factors that might affect the revenues a wind farm will receive in competitive wholesale markets. These factors include (1) a wind multiplier (which permits the simulation of cases with wind output larger or smaller than in the base case), (2) a wind imbalance penalty factor (which permits the simulation of cases in which the system operator imposes penalties on hourly imbalances unrelated to system costs), and (3) creation of an HA price based on the DA and RT prices.

The wind multiplier increases the magnitude of the wind farm's output. This parameter is important because the examples developed here involve a very large control area (with an average load during the 1-week summer period of 36,000 MW) and a small wind farm (with an average output during the same period of 22 MW). The interactions between the wind resource and the system—the primary objective of this project—are negligible for a resource that is less than 0.1% of the total system. The multiplier factor allows one to analyze these interactions when wind accounts for a larger share of the total system load (and generation).[*]

Larger wind farms have more turbines distributed over larger areas than do small farms. Therefore, the relative volatility of the output from a large wind farm should be less. This improvement in wind diversity should affect the hour-to-hour, intrahour-imbalance, and minute-to-minute fluctuations in wind output.[#] This greater diversity should offset some of the costs associated with a wind resource that is a larger share of the electrical system. The diversity benefits would be even greater if the outputs from several geographically dispersed wind farms were treated as a single resource by the system operator.

Although the variation in hour-to-hour output will surely be reduced as the geographic scope of a wind farm increases, I could identify no quantitative method to model this process. I applied the square root of the wind multiplier factor to the regulation component of the wind output. I chose the square-root function because the standard deviation of the sum of several independent variables is equal to the square root of the sum of the squares of the standard deviations of the components. If each turbine's fluctuations (σ_i) are completely independent of the remainder of the wind farm, the total regulation requirement (σ_T) would equal:

---

[*] According to the Minnesota Deputy Commissioner of Energy, the Buffalo Ridge site, on which the Lake Benton wind farm is located, could accommodate up to 4000 MW of wind capacity (Raloff 2001).

[#] Hudson, Kirby, and Wan (2001) examined data from the four metering points for the Lake Benton wind farm. Their analysis showed that the regulation requirement for the wind farm as a whole was substantially less than the requirements for the four subsets treated separately. The total regulation requirement was about 40% less than the sum of the individual requirements.

$$\sigma_T = \sqrt{\sum \sigma_i^2} \quad ,$$

where i refers to an individual turbine and T is the total for the wind farm. In practice, the regulation components of the individual turbines are likely to be modestly positively correlated, which would suggest use of a factor slightly greater than 0.5 but much less than 1.0. For simplicity (and because few data exist to suggest what the power factor should be), I chose 0.5 (the square root).

I applied the ¾th power of the wind multiplier factor to the intrahour-imbalance component of the wind output. I selected this power because it is half way between the 0.5 used for regulation and the 1.0 used for hourly energy.

I also included an imbalance penalty factor (PF) to permit analysis of the effects of a system that discourages energy imbalance by imposing a penalty on such deviations from the hourly schedule. The penalty factor is a percentage reduction in the payment for any overgeneration and the same percentage increase in the charge for any undergeneration. If Wind_t (= $\text{Wind}_{\text{actual}} - \text{Wind}_{\text{schedule}}$) is greater than zero (overgeneration), then the payment is:

$$\text{Payment}_t = \text{Wind}_t \times \text{P}_t \times (1 - \text{PF}) \quad ,$$

where P is the imbalance price in interval t. On the other hand, if Wind_t is less than zero, the charge to the wind is:

$$\text{Charge}_t = \text{Wind}_t \times \text{P}_t \times (1 + \text{PF}) \quad .$$

Finally, I included a factor to define the HA price on the basis of the DA and RT price because PJM has no HA energy market:

$$\text{Price}_{\text{HA}} = \text{Price}_{\text{RT}} + c \times (\text{Price}_{\text{DA}} - \text{Price}_{\text{RT}}) \quad ,$$

where c is a factor (which can vary between 0 and 1) selected by the analyst. I set c to zero for all the analyses presented in Chapter 5. Doing so simplifies interpretation of the results because it eliminates the confounding effects of differences between the DA and RT prices.

WIND REVENUES

The present model, implemented as a Microsoft Excel workbook, performs all the calculations discussed above and then aggregates results to hourly, daily, and weekly totals and averages. If wind bids into the HA market, its payments and charges include:

- HA payments equal to the HA price times the energy scheduled;
- RT hourly charges or payments, equal to the product of the RT hourly price times the difference between the HA schedule and the actual delivery of wind power;

- Any additional intrahour charges or payments; and
- Regulation charges.

If the wind owner participates only in the RT market (i.e., does not schedule any output ahead of time), its payments and charges include:

- Intrahour payments based on the actual wind output and the spot price during each interval of the hour and
- Regulation charges.

Dividing these hourly revenues by the wind output yields an hourly price for the wind (in \$/MWh), which can then be compared with the hourly HA and RT prices.

RESULTS

AUGUST 2000

During the week of August 6, 2000, the unweighted average of the hourly RT price in PJM was \$39.6/MWh. Weighted by hourly electricity consumption, the average price was \$44.7/MWh, 12% higher than the unweighted price. The weighted price is higher because hourly loads and prices are highly correlated ($r = 0.88$).

The hourly wind production averaged 21.8 MW. If the wind farm schedules its production an hour ahead, the price it receives during the week for its product averages \$31.7/MWh. That is, it receives \$34.7/MWh in the HA market, repays \$2.8/MWh in the RT imbalance market for differences between its HA schedule and actual delivery, and pays \$0.3/MWh for regulation.* If the wind farm just participates in the RT imbalance market, it is paid an average of \$31.3/MWh. The price the wind farm receives is much less than the average price (\$31.7 or \$31.3 vs \$39.6) because wind output is *negatively* correlated with load ($r = -0.39$) and therefore price ($r = -0.26$) for this week.

As the size of the wind farm increases relative to the control area, the average price it receives for its output declines (top of Fig. 10). Not surprisingly, the drop is much greater when the wind appears entirely as imbalance energy in the system's RT market. At the extreme, when the wind output is 50 times the actual values, the average price when wind schedules HA is 6% below the price for the actual output. When the wind farm does not schedule HA, the price drop is 31%. The relative decline in wind revenues as the size of the wind farm increases is a consequence of the associated increase in the intrahour imbalance charges. The cost of regulation per MWh of wind production increases with the size of the wind facility, by 20% over the range in wind-farm output considered here.

As the size of the wind facility increases, the imbalance adjustment must also increase to maintain the same CPS performance. When wind is scheduled HA, the adjustment factor increases from 0.2 for the original output to 0.6 when increased by a factor of 10 and 1.0 when increased by a factor of 20 or more. When wind is not scheduled ahead of time, the adjustment

---

*Load, on average, paid \$0.6/MWh of energy for regulation, double what the wind would have been charged. In this case, the regulation component of the wind output is only weakly correlated with the total regulation requirement.

factor increases from 0.7 for the original output to 1.0 when increased by a factor of five or more.

I ran additional cases with the wind output increased by a factor of 10 (equivalent to 0.6% of the system's load) to see how various factors (forecast error, penalty factor, and hourly wind values) affect wind revenues. Reducing the forecast error by 50% saves $6700 for the week, which increases the price wind receives by 0.6%. Completely eliminating the forecast error saves $9300 for the week. The question for the wind community is whether a $348,000 increase in revenues over the course of a year is sufficient to justify the expense of developing and deploying a method to cut forecast errors in half for a 1000-MW wind farm with a capacity factor of 21%. (The benefits of improved wind forecasts may be small in this case because the original forecast explained more than 80% of the variation in hourly wind output.)

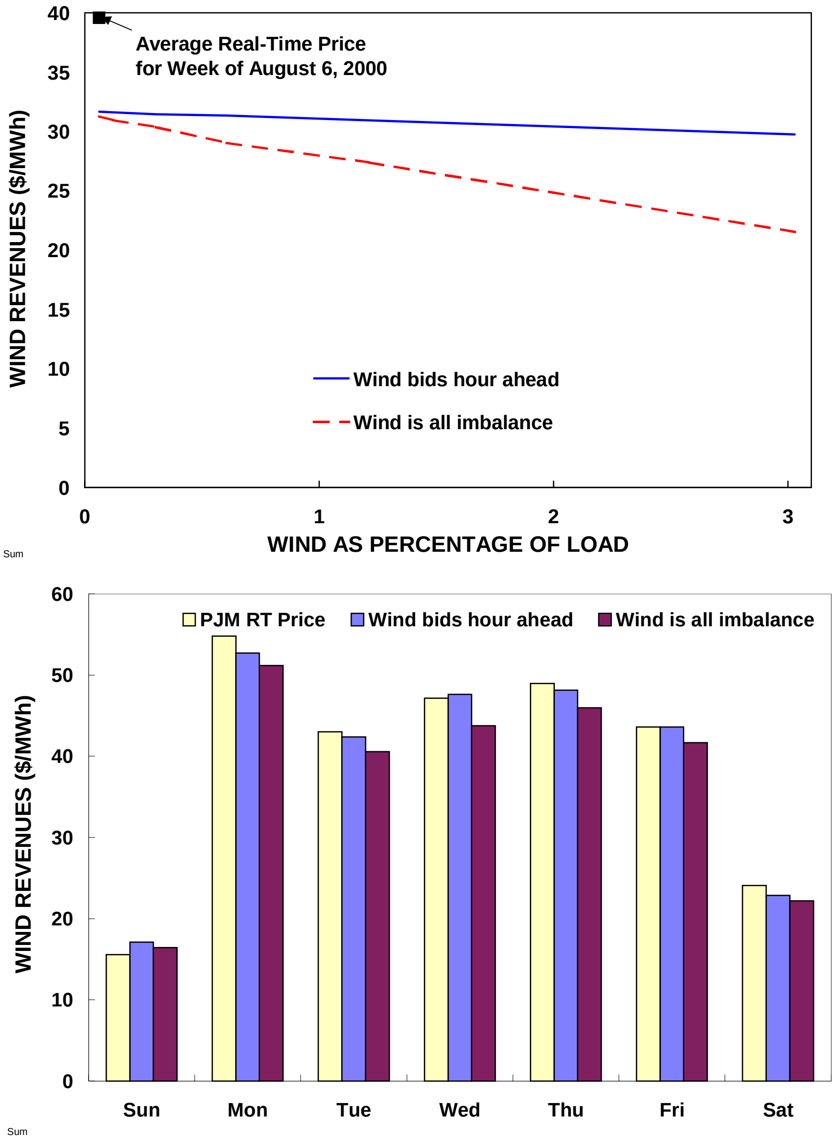


Fig. 10. **Wind revenues for the week of August 6, 2000, as a function of wind output as a percentage of system load (top) and by day of the week for the same minute-by-minute daily wind production (bottom).**

I also ran cases with penalty factors. A 5% penalty costs the wind farm almost $25,000 (2% of revenues) for the week if it schedules HA. If it does not schedule its output ahead of time, the penalty is more than double at $54,000/week (5% of revenues).

Next, I ran a case using the minute-by-minute wind outputs for one day (Thursday, August 10) and applied them to each of the seven days. I selected Thursday because its output (18.6 MW) was close to the hourly average for the week as a whole (21.8 MW). As shown in the bottom part of Fig. 10, the revenues vary tremendously from day to day, ranging from a low of $17/MWh on Sunday to a high of $53/MWh on Monday. This range corresponds exactly to the variation in hourly RT prices that week. Wind revenues are, on average, much higher than in the base case (compare the top and bottom parts of Fig. 10) because the wind output on this day was uncorrelated with system load (*r* = +0.01 instead of −0.39). The price received by wind for its output with Sunday's prices is higher than the PJM RT price because Thursday's hourly wind output is positively correlated (*r* = 0.4) with Sunday's prices. These results show that the wind revenues depend both on the time-varying output of the wind farm and the time-varying electricity prices.

Figure 11 shows the hour-by-hour wind output (scaled up by a factor of 10), the corresponding values of the RT hourly price, and the net revenue the wind farm receives per MWh of output. Except when the wind output is very low, the net price wind receives tracks the RT hourly price closely.

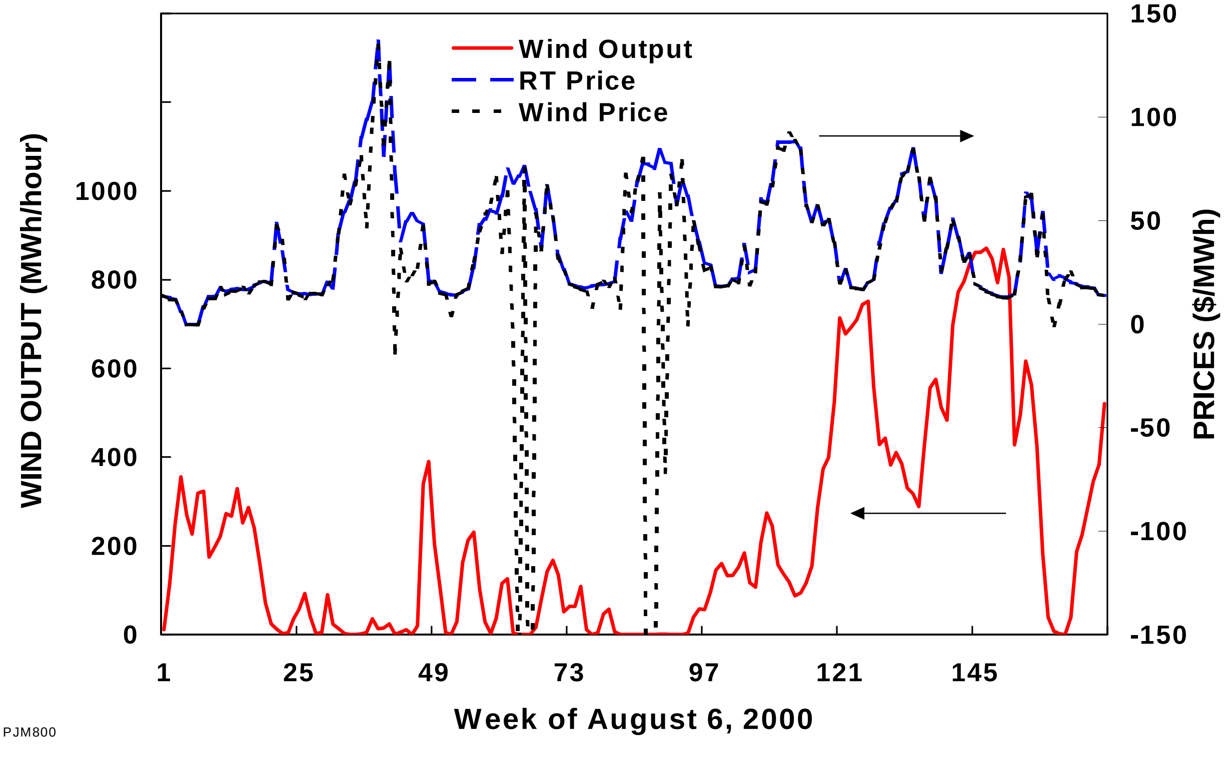


Fig. 11. **Hourly values of wind output (times 10, left axis) and RT prices and the prices wind receives if it schedules hour ahead (right axis).**

JANUARY 2001

During the week of January 15, 2001, the unweighted average of the hourly RT price in PJM was \$31.1/MWh (21% lower than during the August week discussed above). Weighted by hourly electricity consumption, the average price was \$32.4/MWh, 4% higher than the unweighted price. The weighted price is only slightly higher because hourly loads and prices are only weakly correlated (r = 0.55, compared with 0.88 for August 2000).

The hourly wind production averaged 37.7 MW, 73% more than during the week in August 2000. If the wind farm schedules its production hour ahead, the price it receives during the week for its output averages \$33.7/MWh. Specifically, it receives \$34.6/MWh in the HA market, repays \$0.7/MWh in the RT imbalance market for differences between its HA schedule and actual delivery, and pays \$0.05/MWh for regulation. If the wind farm just participates in the RT imbalance market, it is paid an average of \$32.9/MWh. Unlike the situation in August, the price the wind resource receives is higher than the average price (\$33.7 or \$32.9 vs \$31.1) because wind output is essentially uncorrelated with load (r = −0.04) and is positively correlated with RT price (r = 0.16) for this week.

The regulation charges to the wind farm differ by a factor of six between August and January (the equivalent of \$0.31/MWh of wind energy produced in August, compared with only \$0.05/MWh in January). This difference is a consequence of three sets of variables. First, the total cost of regulation to the PJM system was 53% higher in August than in January because both the amount of regulation per hour (426 vs 382 MW) and the price of regulation (\$53.3 vs \$41.9/MW-hr) were higher in August. Second, wind's share of regulation was 123% higher in August than in January (0.033% vs 0.015%). Finally, the average hourly wind production was 43% less in August than in January (22 MW vs 38 MW). This comparison illustrates the volatility of wholesale electricity markets and the various factors that can affect the revenues and charges a wind farm might experience.

Consistent with the August results, as the size of the wind farm increases relative to the control area, the average price it receives for its output declines (top of Fig. 12). Again, the drop is much greater when the wind output appears entirely as imbalance energy in the system's RT market. At the extreme, when the wind output is 50 times the actual values, the average price when the wind farm schedules HA is 3% below the price for the actual output. When it does not schedule HA, the price drop is 44%. The cost of regulation per MWh of wind production increases with the size of the wind facility, by 35% over the range in wind-farm output considered here.

I ran additional cases with the wind output increased by a factor of 10 (equivalent to 1.2% of the system's load) to see how various factors affect wind revenues. Reducing the forecast error by 50% saves \$9400 for the week, which increases the price wind receives by

0.4%. Completely eliminating the forecast error saves $13,000 for the week. Again, the question is whether a $489,000 increase in annual revenues (20% more than calculated for the week in August 2000) warrants the expense of developing and using a method to cut forecast errors in half for a 1000-MW wind farm with a capacity factor of 36%.

I also ran cases with penalty factors. A 5% penalty costs the wind farm $20,000 (almost 1% of its revenues) for the week if it schedules HA. If it does not schedule its output ahead of time, the penalty is four times higher at $86,000 per week.

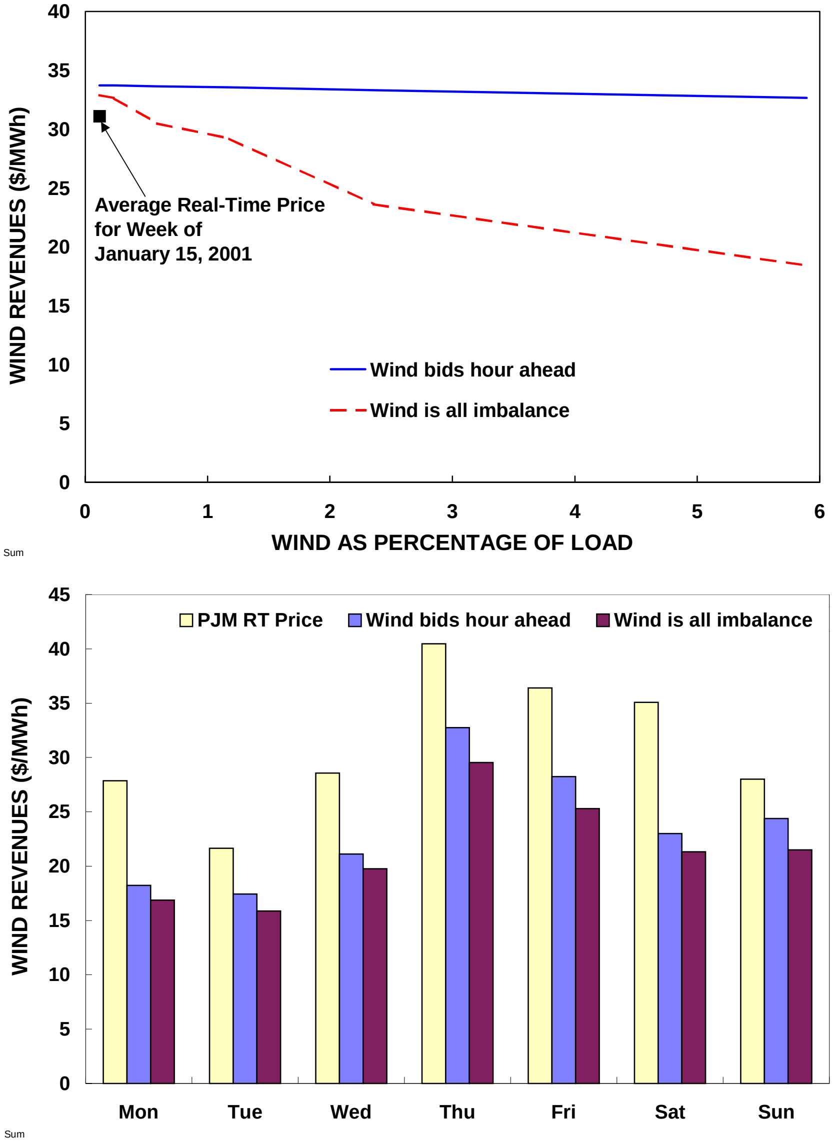


Fig. 12. Wind revenues for the week of January 15, 2001, as a function of wind output as a percentage of system load (top) and by day of the week for the same minute-by-minute daily wind production (bottom).

Next, I ran a case in which I took the minute-by-minute wind output for one day (Friday, January 19) and applied those data to each of the seven days. I selected Friday because its output (39.2 MW) was close to the hourly average for the week as a whole (37.7 MW). As shown in the bottom part of Fig. 12, the revenues vary substantially from day to day, ranging from a low of $17/MWh on Tuesday to a high of $33/MWh on Thursday. This range corresponds exactly to the variation in hourly RT prices that week. Wind revenues are, on average, much lower than in the base case (compare the top and bottom parts of Fig. 12), the opposite of what we observed for August, because the wind output on this day was negatively correlated with system load ($r = -0.84$ instead of -0.04).

Figure 13 shows the hour-by-hour wind output (scaled up by a factor of 10), the corresponding values of the RT hourly price, and the net revenue the wind farm receives per MWh of output. As was true for the August data, except when the wind output is very low, the net price wind receives tracks the RT hourly price closely.

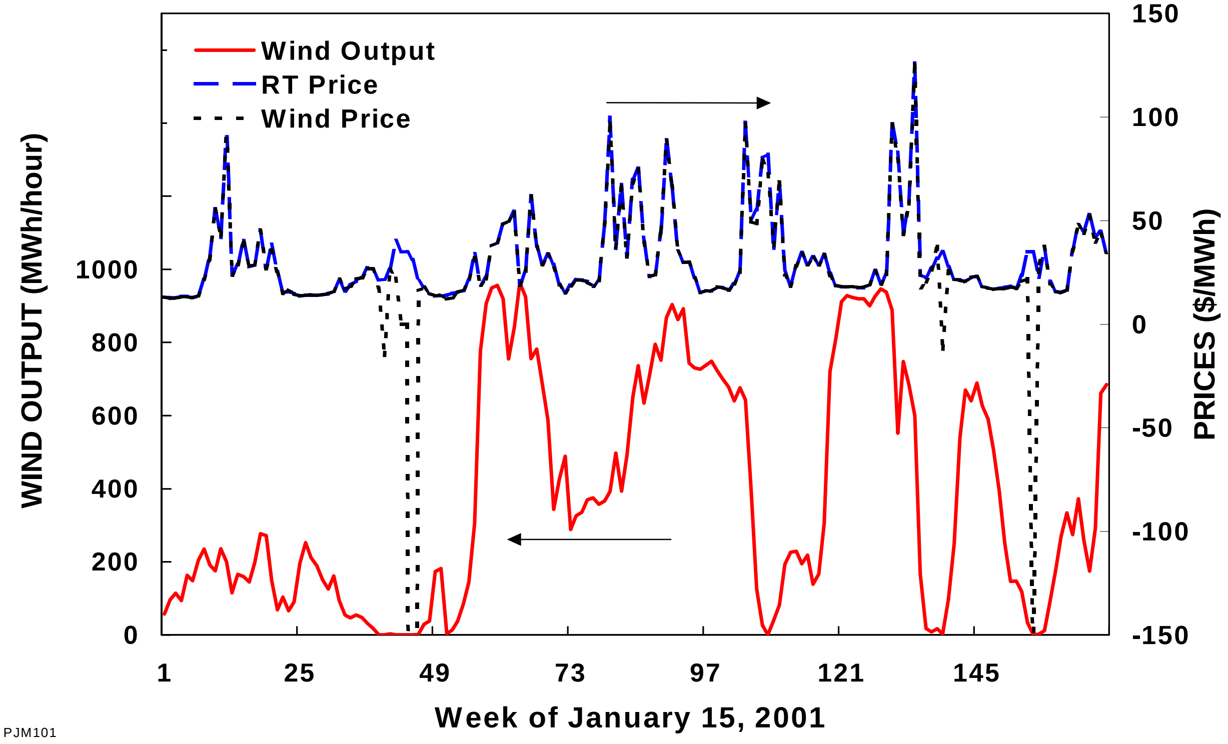


Fig. 13. **Hourly values of wind output (times 10, left axis) and RT prices and the prices wind receives if it schedules hour ahead (right axis).**

CHAPTER 6

CONCLUSIONS

The key lesson to be learned from the development and application of this method is that it is feasible and practical to *calculate* the costs and revenues associated with the delivery of electricity from a volatile and unpredictable resource. It is not necessary—and certainly not desirable—to estimate these costs and payments based on speculation and ideology.

This method, because it is empirical, requires detailed data on both the wind farm in question and the control area within which the farm is electrically (not necessarily, physically) located. The empirical basis of this method means that it cannot be readily applied to a wind facility that is not yet operational or to a wholesale electricity market that does not yet exist.

The method requires large amounts of data, in particular 1-minute averages for several factors related to the control area as well as wind output. These data include 1-minute values of area control error and system load for the control area as well as wind output. Data required at the intrahour-interval level include control-area dispatch and energy prices. Data required at the hourly level include CPS performance, forward and real-time energy prices, and regulation prices. All these data should be readily available from the system operator and the wind-farm operator.

In addition, the calculations required to produce the present results are straightforward and amenable to incorporation in a simple workbook. The method models the interaction of the wind output with the hour-ahead energy market and the real-time balancing market; it also calculates the regulation requirements for the wind resource.

A key feature of this analytical method is that the system operator need not acquire regulation and intrahour-balancing resources to counter every change in output from the wind farm. All the system operator need do, in response to the time-varying output of the wind facility, is maintain the same average CPS performance it would have without the wind resource. In other words, this method treats wind the same way that any time-varying load or generator should be treated in competitive wholesale operations and markets.

One should not generalize too much from the results presented here because they apply to only one wind farm, to one control area, and to two one-week periods (in August 2000 and January 2001). Nevertheless, here goes:

- Scheduling wind output ahead of time (e.g., in the hour-ahead energy market) yields greater revenues than having the wind appear entirely as intrahour imbalance energy.

- The benefits of accurately scheduling the wind hour ahead increase as the size of the wind facility increases. These benefits suggest that the value of accurate forecasts of wind output could be substantial.

- The average revenue per MWh of wind production, all else being equal, declines as the size of the wind facility increases. (The magnitude of this effect may be overstated by the present method.)

- The cost of regulation is a small fraction of the total revenues the wind resource receives, on the order of 5 to 30 cents per MWh of wind energy produced. These costs are lower than the regulation cost borne by PJM customers, which average about 60 cents per MWh.

- The comparison between results obtained for August 2000 and January 2001 emphasize how strongly wind revenues depend on hourly spot prices. Because the wind output cannot be controlled, its revenues depend on when the wind blows and the correlation between wind output and hourly spot prices. These results suggest that those examining alternative locations for wind farms should consider prices and revenues as well as local wind speeds.

- Market design can affect the revenues and costs a wind farm faces. Penalties unrelated to system costs unfairly rob wind farms of revenues they would otherwise earn. These penalties can be explicit or they can be a function of poor market design (which leads to prices that do not accurately reflect the value of the wind resource).

ACKNOWLEDGMENTS

I thank the Energy Foundation, Land and Water Fund of the Rockies, Xcel Energy, and FPL Energy for their financial support of this project. I thank Terry Black (project manager) for his advice and support throughout the course of this project. I appreciate the time that Demy Bucaneg, Enron Wind, devoted to providing the wind data used here. I appreciate the time and effort that Bill Herbsleb, PJM Operational Compliance Department, devoted to collecting and organizing the data needed for this project and helping me interpret those data. I thank Brendan Kirby for his technical advice during the course of this project and for reviewing an early draft of this report. I thank Terry Black, Eric Blank, Jack Cadogan, James Caldwell, Adam Capage, Yihsu Chen, Edgar DeMeo, Mario DePillis, Thomas Foley, Bill Herbsleb, Brendan Kirby, Ronald Lehr, Eric Leuze, Edward Lo, Mark McGree, Michael Milligan, John Nielsen, Kevin Porter, Mark Smith, Ann Thompson, Yih-huei Wan, and Robert Zavadil for their helpful comments on the draft of this report.

REFERENCES

R. Abernathy and E. Leuze 2001, “Proposed Board Resolution on Intermittent Resources,” Memorandum to California Independent System Operator Governing Board, Folsom, CA, July 18.

J. H. Caldwell, Jr. 2001, “Testimony Before the U.S. Senate Committee on Energy and Natural Resources,” American Wind Energy Association, Washington, DC, August 7.

C. R. de Azua 2001, “Wind Power: Poised for Takeoff?” *Public Utilities Fortnightly* **139** (15), 38–43, August.

Energy Information Administration 2000, *Annual Energy Outlook 2001, With Projections to 2020*, DOE/EIA-083(2001), U.S. Department of Energy, Washington, DC, December.

ERCOT ISO 2001, *ERCOT Protocols, Section 6: Ancillary Services*, Taylor, TX, June 1.

E. Hirst 2001, *Real-Time Balancing Operations and Markets: Key to Competitive Wholesale Electricity Markets*, Edison Electric Institute, Washington, DC, and Project for Sustainable FERC Energy Policy, Alexandria, VA, April.

E. Hirst and B. Kirby 1997, *Ancillary-Service Details: Dynamic Scheduling*, ORNL/CON-438, Oak Ridge National Laboratory, Oak Ridge, TN, January.

E. Hirst and B. Kirby 1998, *Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services*, NRRI 98-05, National Regulatory Research Institute, Columbus, OH, January.

E. Hirst and B. Kirby 2000, “Time-Averaging Period for the Regulation Service,” *IEEE Power Engineering Review* **20** (7), 10–12, July.

R. Hudson, B. Kirby, and Y. Wan 2001, *Regulation Requirements for Wind Generation Facilities*, Oak Ridge National Laboratory, Oak Ridge, TN, and National Renewable Energy Laboratory, Golden, CO, June.

Interlaboratory Working Group 2000, *Scenarios for a Clean Energy Future*, ORNL/CON-476, Oak Ridge National Laboratory, Oak Ridge, TN, November.

B. Kirby and E. Hirst 2000, *Customer-Specific Metrics for the Regulation and Load-Following Ancillary Services*, ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge, TN, January.

M. Milligan 2001, *Testimony of Michael Milligan*, In the Matter of the Application of Public Service Company of Colorado for an Order Approving Its 1999 Integrated Resource Plan, Docket No. 99A-549E, before the Colorado Public Utilities Commission, Golden, January 31.

New York Independent System Operator 2001, *Filing of Tariff Revisions to Modify Rules Governing Regulation and Frequency Response Service, Uninstructed Overgeneration and Persistent Undergeneration*, Docket No. ER-01-2251-000, submitted to the U.S. Federal Energy Regulatory Commission, Schenectady, NY, June 6.

North American Electric Reliability Council 1999, *NERC Operating Manual*, “Policy 1 — Generation Control and Performance,” Princeton, NJ, November.

North American Electric Reliability Council 2000, *Generating Unit Statistical Brochure, 1995–1999*, Princeton, NJ, October.

J. Raloff 2001, “Power Harvests, The Salvation of Many U.S. Farmers May Be Blowing in the Wind,” *Science News* **160** (3), 45–47, July 21.

Southwest Power Pool 2001, *SPP Market Guide (Version 1.1)*, Little Rock, AR, May.

U.S. Federal Energy Regulatory Commission 1996, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule,* Docket Nos. RM95-8-000 and RM94-7-001, Order No. 888, Washington, DC, April 24.

U.S. Federal Energy Regulatory Commission 1999, *Regional Transmission Organizations*, Order No. 2000, Docket No. RM99-2-000, Washington, DC, December 20.

Y. Wan and L. Walsh 2000, *Wind Power Plant Monitoring Project Report,* National Renewable Energy Laboratory, Golden, CO, August.

R. M. Zavadil 2001, personal communication, Electrotek Concepts, Knoxville, TN, August.

C:\Data\Wpd\Rest\wind final.wpd