INTEGRATING LARGE AMOUNTS OF WIND ENERGY WITH A SMALL ELECTRIC-POWER SYSTEM

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SUMMARY

The cost of building and operating wind farms continues to decline. And governments increasingly encourage development of renewable energy resources. As a consequence, the amount of wind capacity is growing, raising important questions about the integration of wind output with electric-power systems. These questions have physical (especially reliability) and economic consequences.

This report examines the integration of varying amounts of wind capacity (from 200 to 2,000 MW) with a small utility that has a peak load of less than 5,000 MW. We developed and applied quantitative methods to calculate the payments and charges to a wind farm from the day-ahead unit commitment through real-time minute-to-minute operations, encompassing four time periods:

- Day-ahead unit commitment (12 to 36 hours before the operating hour),
- Real-time dispatch (current operating hour),
- Intrahour balancing (load following), and
- Regulation.

As the amount of wind capacity within a utility service area increases, the net value of wind per MWh of wind-energy output declines. This decline is caused by four key factors. First, as more and more wind displaces conventional generation, the utility's production costs decline. As a consequence, each additional MWh of wind energy adds less economic value than the earlier ones. Second, errors in the day-ahead wind forecast can cause physical and reliability problems in real time. For example, if the wind forecast is much higher than actual wind output, the utility will have to quickly ramp up its other generating units (and perhaps bring online units currently not operating) to cover the wind's shortfall. Doing so requires generators that can ramp (in MW/minute) rapidly and that can be turned on and off quickly. Third, *inter*hour changes in wind energy may require the utility to adjust its other generation to compensate for the wind's variability, Finally, *intra*hour variability in wind output imposes costs on the utility for load following and regulation.

For the situation analyzed here, small wind farms would receive net payments close to the utility's zero-wind marginal cost, almost $30/MWh (Fig. S-1). The payment for a 400-MW wind farm would drop to about $23/MWh; a 1,000-MW wind farm would receive only $16/MWh. This decline in payment per MWh of wind energy is caused by the drop in marginal costs that would occur with the addition of any new low-cost generation to the system and the costs of wind integration (i.e., errors in the day-ahead forecast of wind output, interhour variations in wind output, and intrahour variability in wind output).

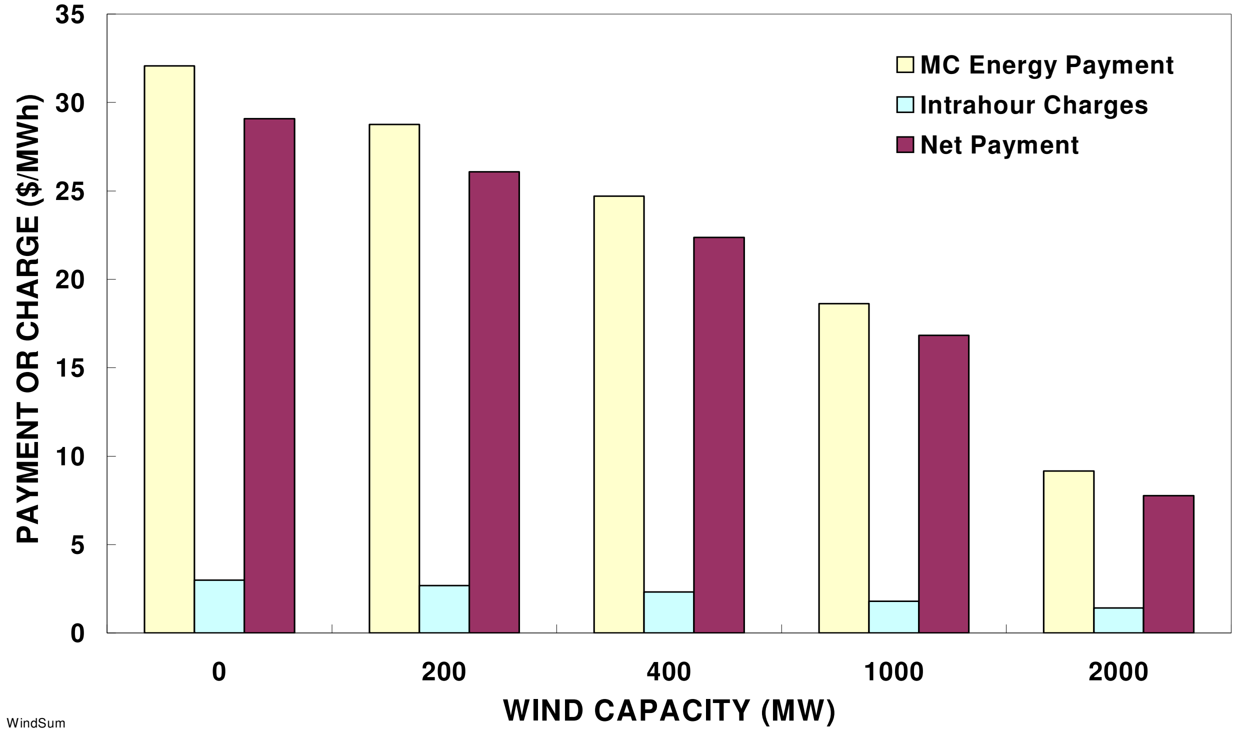

Fig. S-1. **Energy payments, charges for intrahour balancing and regulation, and net payments to wind farms as a function of wind capacity.**

LIST OF ACRONYMS

ACE	Area control error
AGC	Automatic generation control
CoV	Coefficient of variation
CPS	Control Performance Standard
DA	Day ahead
FERC	U.S. Federal Energy Regulatory Commission
LF	Load following
λ	Lambda, marginal cost of power production
NERC	North American Electric Reliability Council
O&M	Operations and maintenance
RT	Real time
RTO	Regional transmission organization
SMD	Standard market design
UC	Unit commitment
WF	Weighting factor
WS	Wind speed

INTRODUCTION

BACKGROUND

As the amount of wind capacity installed in the United States increases, integration of wind output with electric-power systems becomes more complicated. Integrating 100 MW of wind capacity with a 30,000-MW power system is much simpler than integrating 2,000 MW of wind with a 3,000-MW system. Wind integration raises issues that do not arise with traditional generating units because of three unique characteristics of wind farms and their output: limited control, relative unpredictability, and temporal variations (Hirst 2001b). These factors require the adjustment of other generating units to account for unanticipated wind outputs.

This report, unlike earlier analyses of wind integration, focuses on large wind farms located in a small utility service area.* Specifically, this project considers various amounts of wind, ranging from 200 to 2,000 MW, integrated with a small utility system with a peak demand of less than 5,000 MW. The data presented in this report have been disguised to protect the identity of the utility and the specific resources within that system.

This project focuses on the revenues a wind farm might receive from selling its energy output to this utility and the costs it might incur for integration. These revenues and costs are analyzed over four periods (Fig. 1):

- Day-ahead (DA) unit commitment (UC, 12 to 36 hours before the operating hour);
- Real-time (RT) dispatch (current operating hour);
- Intrahour balancing (sometimes called load following, LF); and
- Regulation.

These revenues and charges are calculated in two different ways. One way simulates the operation of a traditional utility and uses average production costs to calculate the payments. The second approach simulates the operation of DA and RT wholesale markets, as envisioned

*See Dragoon and Milligan (2003), Electrotek Concepts (2003a and b), Hirst (2001b and 2002), and Kirby et al. (2003) for examples of such analyses. The wind penetration in these studies ranged from less than 1% to 29%.

in the Standard Market Design (SMD) proposed by the U.S. Federal Energy Regulatory Commission (FERC 2002).*

The methods developed and applied here advance our understanding of the costs and benefits of wind electricity production. Two prior studies conducted by Hirst (2001b, 2002) did not accurately simulate the diversity benefits of more and larger wind farms within a single control area. Electrotek (2003a) did not analyze the effects of different sizes of wind farms. Dragoon and Milligan (2003) and Electrotek (2003b) were not able to analyze intrahour costs of wind integration. Kirby et al. (2003), as well as several other studies, looked only at small wind farms in large electrical systems. The present study demonstrates a comprehensive method to calculate the revenues and charges facing a wind farm from day-ahead scheduling through minute-by-minute real-time operations.

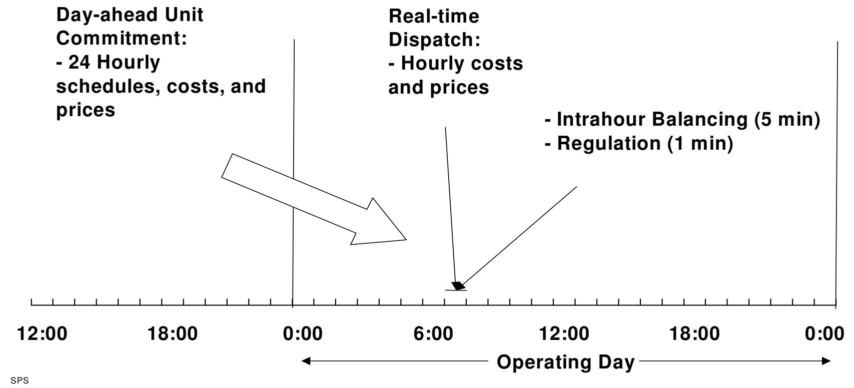

Fig. 1. Time line showing day-ahead unit commitment, hourly dispatch, intrahour balancing, and regulation.

Although this project takes a comprehensive view of energy integration, several important wind-integration issues are not considered here:

- Planning reserves: Should wind farms qualify for installed capacity? If so, how should the appropriate amount be calculated? More generally, how does the addition of wind to a utility system affect its generation and transmission planning?

- Contingency reserves: Should wind be responsible for some spinning and supplemental reserves, or are these functions implicit in the intrahour balancing analyzed here?#

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*Resources bring *value* to power systems and, in return, receive *payments* for the benefits they provide. In an ideal world, value and payments are equal. In practice, utility tariffs, approved by state regulators or FERC, only approximate payments to value and charges to costs (Dragoon 2004). In this report, we focus on the value of wind farms and the costs such resources impose on electrical systems and assume that these benefits and costs are accurately reflected in payments and charges.

#The Northwest Power Pool (2003) recently approved a requirement that wind be responsible for contingency reserves: "Control areas with wind powered generation shall carry an amount of energy equal to 5% of the Load Responsibility carried by wind power generation as Contingency Reserve." These reserves are intended to protect against "[l]osses of wind power generation due to electrical failure, mechanical failure, or high-speed cutout due to wind velocity … ."

- Transmission: What are the costs for interconnection, access (e.g., firm v nonfirm service), congestion, and losses to transport wind output (often sited in remote locations) to load centers?*

These issues apply to all resources, not just wind, but may be more important for wind.

The next section explains how system operators schedule generating resources day ahead to meet expected loads hour by hour during the operating day and then dispatch those resources in real time to maintain the necessary generation:load balance. Chapter 2 describes the data available for this project. Chapter 3 discusses the characteristics of the wind farms and utility system used to develop results. Chapter 4 explains the analytical methods developed and used in this project, and Chapter 5 presents the results obtained with the data of Chapter 2 and the methods of Chapter 4. Chapter 6 offers conclusions based on the analytical methods and results developed here.

SYSTEM OPERATIONS

Electric utilities typically run their UC optimization computer programs 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 the following day. These characteristics include current unit status, minimum and maximum output levels, maximum (normal and emergency) ramprates, startup and shutdown costs and times, minimum runtimes, minimum offline times, planned maintenance outages and unit derates, 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 information on the state of the transmission system expected for the operating day (in particular, any lines or transformers out of service for maintenance), which are included in the model as constraints.

The optimization model is then run to identify the least-cost way to meet the following day's electricity demands while maintaining reliability. Least cost refers to the startup and shutdown, variable fuel, and variable operations and maintenance (O&M) costs of the generating units used to produce energy during the operating day. The reliability requirements include the ability to withstand the loss of any single generation or transmission element while maintaining 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

* "[M]ore than 1,000 nameplate MW of wind generation has been built in west Texas in the last three years, and the relatively weak transmission system in the area has required almost daily limitation of the output of this renewable generation resource" (NERC 2003).

unit will start, operate, and then be turned off). Second, given the units that are online each hour, it sets the level of output for each unit to meet load at the lowest cost.

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 few minutes. This model forecasts load for the next interval (e.g., five minutes) 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 to see if any quick-start units (e.g., combustion turbines and hydroelectric units) should be turned on or off 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, ramprates, and run times.

After the fact, these RT costs can be broken into three categories:

- RT hourly production costs, the variable fuel plus O&M costs to meet hourly loads,
- Intrahour balancing, the variable costs to respond to changes in load at the 5-minute level, and
- Regulation, the variable costs to respond to minute-to-minute changes in system load within each 5-minute interval.

The balancing and regulation functions are required to maintain the necessary generation:load balance, as measured by the system's area control error (ACE); see Hirst (2001a). ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of Interconnection frequency; it measures how well the system operator maintains its generation-load balance.

The North American Electric Reliability Council (NERC 2001) requires that each control area maintain its generation:load balance within limits set by its Control Performance Standard (CPS) 1 and 2. Neither CPS1 nor CPS2 requires a control area to maintain a zero ACE. Small imbalances are permissible, as are occasional large imbalances. Both CPS1 and 2 are statistical measures, 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. To meet the CPS requirements, the system operator need not acquire regulation and load-following resources to exactly counter 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.

FERC's (2002) SMD calls on regional transmission organizations (RTOs) to operate integrated DA markets for energy, ancillary services (regulation and contingency reserves), and transmission congestion. 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).

In the kinds of market-based systems described above, the inability to accurately forecast loads or generation output day ahead has 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. However, if the RTO's DA forecast of load is much higher than the DA schedule, it would commit additional resources to ensure that reliability is maintained in real time. The cost to commit these additional generators would be borne by the entities with scheduling errors.

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 commit additional resources DA to prevent reliability problems from occurring in real time if the actual and forecast output and load differ materially. Alternatively, if loads are much lower than forecast DA, the system operator might have to decommit units in real time. Thus, the utility might incur costs to start up or shut down additional units and to run units out of economic merit order if scheduling errors are large. In either case, the utility may incur extra fuel, O&M, and capital-additions costs associated with the extra movement of its generating units.

IMPLICATIONS FOR LARGE WIND FARMS

If the amount of wind capacity scheduled (or bid) DA is small relative to the control area, the processes outlined above work smoothly and well. However, if the amount of wind is large relative to the control area, discontinuities can occur in both market and regulated environments.

Consider a control area with, say, 4,000 MW of conventional generation. Assume 1,500 MW of wind capacity is scheduled for a particular operating hour. If the amount of wind production that hour is only 1,000 MW, the 500-MW deficit must be made up by other generators that are already online or can be started rapidly (e.g., combustion turbines that can be turned on and reach their full output within 10 to 30 minutes). If the utility does not have sufficient flexible resources to fill this 500-MW deficit, it will either make emergency purchases from neighboring control areas or it will violate security constraints, raising reliability problems for its customers and surrounding control areas. A similar problem could occur if the amount of wind production was 2,000 MW, 500 MW more than scheduled. In this case, the utility might back down (or decommit) some of the generation already on line. These hourly and intrahour ramping and commitment/decommitment actions are costly; these costs should be assigned to the entities that scheduled inaccurately day ahead.

DATA RESOURCES

This project used two sets of data to conduct these analyses, one on wind speeds and the energy output from wind farms and the other on the operation of the utility's bulk-electric system and its associated production costs. Most of these data are at the hourly level and are used to calculate the revenues a wind farm would receive for its DA schedules and its RT delivery of energy. Other data at the 1-minute level are used to calculate the costs of intrahour balancing and regulation. Because detailed data are needed to calculate the revenues and costs to integrate wind farms with power systems, they are not always available. Therefore, the data used in this project come from different time periods and are, in some cases, based on simulations rather than actual experience.

WIND SPEED AND OUTPUT

One major wind farm is currently operating within the utility's service territory. We received hourly data on the output from this wind farm (with a capacity of less than 100 MW) for a 1-year period, April 2002 through March 2003. We also received 1-minute data on the output from this wind farm for two 1-week periods in spring and summer.

Because the primary purpose of this project is to simulate the effects of integrating large amounts of wind with a small electrical system, the data from this wind farm, because of its small size, was of limited value. As explained in Chapter 4, we used data on hourly wind speed from five locations within the region to simulate the output of wind farms ranging in size from 200 to 5,000 MW. These data cover the 1-year period from May 1997 through April 1998. These five sites lie in a circle with a diameter of about 200 miles.

UTILITY SYSTEM OPERATIONS AND COSTS

We received data on hourly system load for the same periods as those noted above for the wind resources, April 2002 through March 2003 and May 1997 through April 1998. We also obtained DA hourly load forecasts for April 2002 through March 2003 as well as the RT hourly values of system lambda. Lambda (λ) is the marginal cost of power production, including fuel plus O&M, expressed in \$/MWh.

The utility also provided 1-minute data on system load and ACE as well as hourly lambda for the two 1-week periods for which wind-farm output was available.

We received data on the physical and cost characteristics of the utility's generating units. These data include primary fuel type, average heat rate, fuel and variable O&M costs, minimum and maximum capacity, and ramprate. We used these data to construct a supply curve for intrahour dispatch.

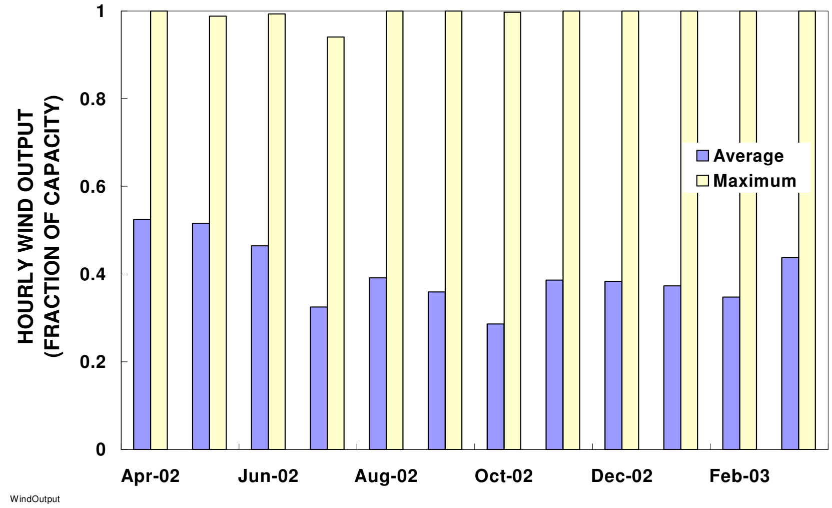
Finally, we received outputs from the computer model this utility uses to perform its DA UC and to price RT hourly dispatch. The outputs from this model include, for both the DA and RT runs, startup, fuel, variable O&M, and purchase and sale costs (all in $/hr), and system lambda ($/MWh). As explained in Chapter 4, this model was used to simulate the operations and costs of the utility system with and without various amounts of wind capacity for three months in spring, summer, and winter.

WIND AND UTILITY CHARACTERISTICS

WIND FARM

From April 2002 through March 2003, the average output from the one wind farm operating in this utility service area was equivalent to a 39% capacity factor. The average output varied from month to month, from a low of 29% in October to a high of 44% in April (top of Fig. 2). The standard deviation of the hourly wind output was 81% of the average output, suggesting substantial hour-to-hour variation in wind output. The bottom part of Fig. 2 shows how wind output varies during a particular month.

The correlation between hourly wind output and system load is zero ($r = -0.1$). This lack of correlation is important because power-production costs and spot prices are typically highly correlated with system load.



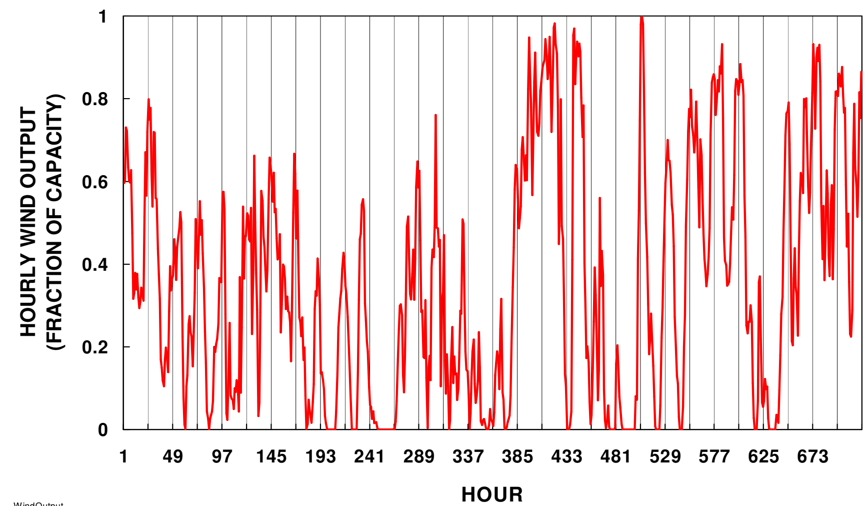


Fig. 2. Hourly data on wind output by month from April 2002 through March 2003 (top) and hour-by-hour for one month.

SIMULATED WIND FARMS

Because the capacity of this wind farm is much less than what we wanted to analyze in this project, we used wind-speed data from five sites throughout the utility service area to simulate the outputs from wind farms of various sizes, up to 5,000 MW. Even though the time periods are different (April 2002 through March 2003 v May 1997 through April 1998), the overall characteristics of the simulated wind farms are similar to those for the operating wind farm (Table 1).

Table 1. Comparison of the characteristics of the wind farm and the average of the simulated outputs from five sites (hourly output)

	Operating wind farm	Simulated wind farms
Capacity factor, %	39	34
Coefficient of variation, %	81	82
Monthly hourly minimum/annual average, %	72	78
Monthly hourly maximum/annual average, %	131	129

Figure 3 summarizes the simulated outputs for five wind farms, with an aggregate capacity of 200 MW. Comparing Figs. 2 and 3 shows considerable similarity. These similarities between the actual and simulated outputs suggest that the simulations are a reasonably proxy for what might occur with the operation of additional wind capacity within the utility service area.

UTILITY

For the same 12-month period for which wind output are available (April 2002 through March 2003), the utility hourly system load ranged from 2,180 to 4,630 MW, with an average of 2,950 MW. The load factor that year was 64%. The coefficient of variation (CoV) was 16%, showing how much less variable system load is than wind output, which had a CoV of 81%.

For May 1997 through April 1998, the level and pattern of system load were similar to those for April 2002 through March 2003. For these two 1-year periods, the hourly average, maximum, minimum, and standard deviation for 2002/03 were 12 to 18% higher than for 1997/98. In addition, the correlation coefficient between the two sets of load data was 0.84. This similarity lends further support to our use of wind-speed data from 1997/98 with load data from 2002/03.

Because wind output and load are completely uncorrelated, we decided to use the simulated wind output for 1997/98 with utility load data for 2002/03. We selected the most recent year of load data because detailed operational and cost data (in particular, results of the DA and RT UC model runs) were not available for earlier years. This time shifting should not affect the validity of the results reported here because load and wind output are uncorrelated.

System load is, on an hour-by-hour basis, predictable, following a consistent daily pattern (top of Fig. 4). Although this pattern varies from season to season it is stable during each season. (The correlation coefficients among the hourly loads across the five days shown in Fig. 4 range from 0.92 to 0.99.)

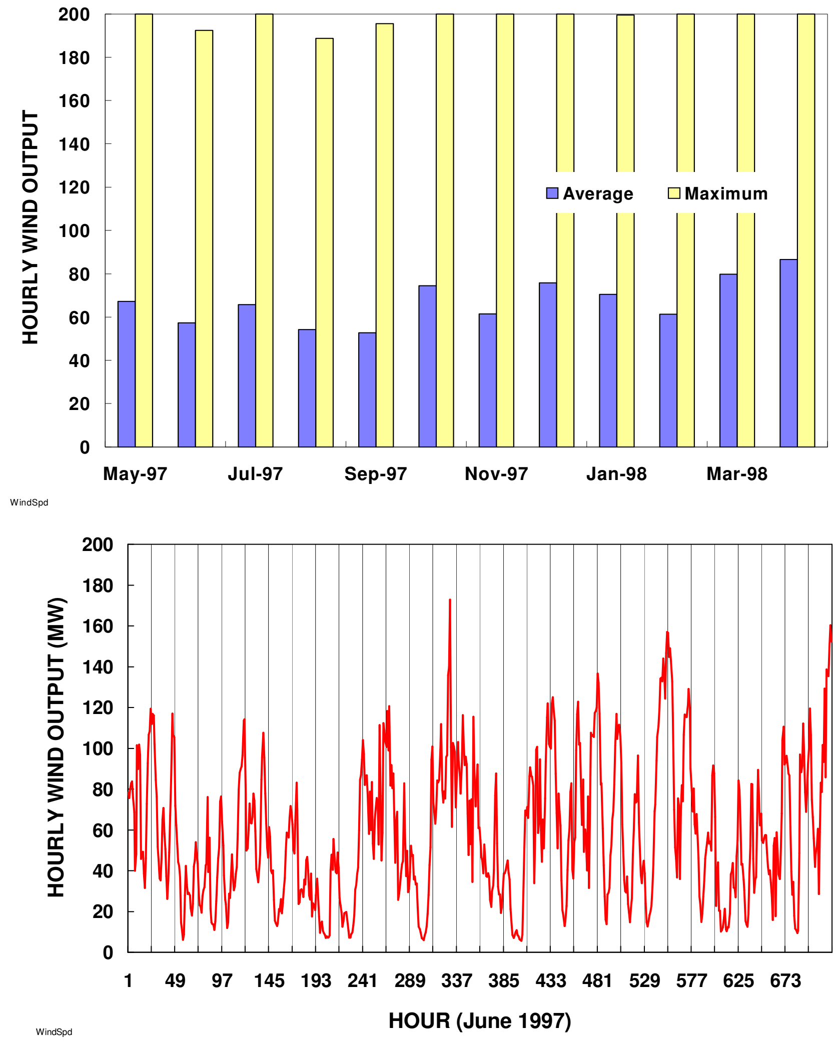
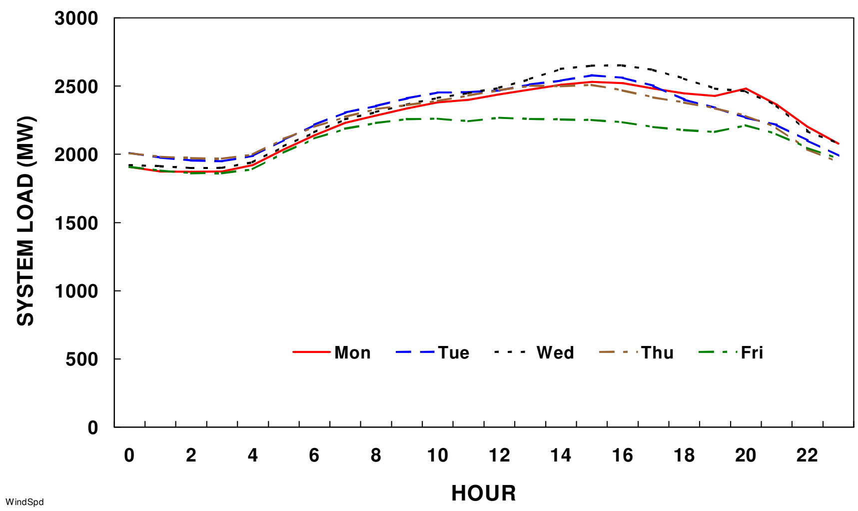


Fig. 3. Simulated hourly wind outputs from five sites by month from May 1997 through April 1998 (top) and hour-by-hour for June 1997 (bottom).

On the other hand, the wind output shows no consistency from day to day (bottom of Fig. 4). The correlation coefficients among hourly wind output across these five days range from −0.6 to +0.8, with an average of −0.1.

This utility owns 4,500 MW of coal- and gas-fired generating capacity. In addition, the utility has agreements to purchase energy from an additional 1,200 MW of generation from other companies.



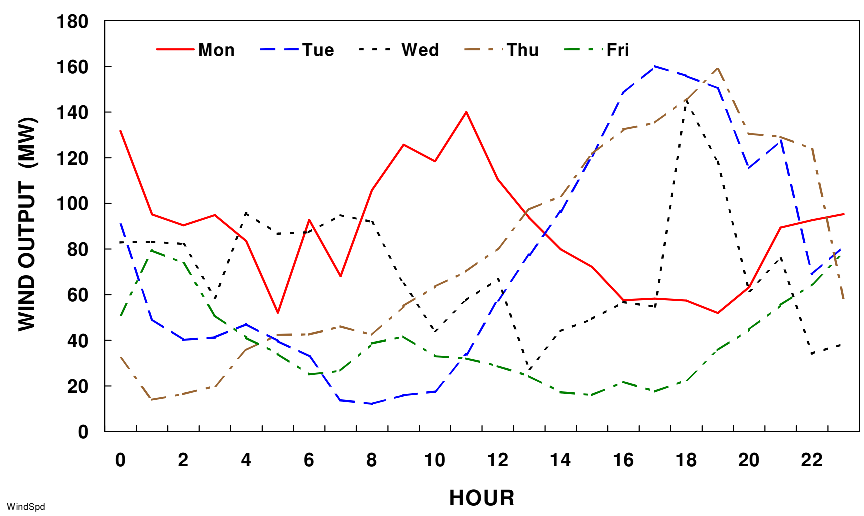


Fig. 4. **Hourly system load (top) and wind output (bottom) for five consecutive weekdays.**

ANALYTICAL APPROACH

SIMULATING SEVERAL LARGE WIND FARMS

As noted earlier, a unique element of this project is the analysis of a large amount of wind integrated with a small electrical system. Given the existence of less than 100 MW of operating wind capacity within the utility's service area, it is not obvious how to "create" several thousand megawatts of wind capacity in this area.

Fortunately, data on wind speeds at five locations within the service area were available. These data include average hourly wind speeds at various heights from May 1996 through April 1997.

We adjusted the wind speeds from each of the five sites to a standard 72-meter height using the following formula:

$$WS_{72} = WS_{height} \times (72/height)^{1/7} ,$$

where WS is wind speed in meters/second, height is the height in meters of the data-collection station (either 40 or 50 meters) and 1/7 is the power factor used to convert wind speed from one height to another (Milligan 2003).

As shown in Table 2, the correlation among the sites in wind speed is quite low, presumably because of the substantial geographical dispersion among the five locations (about 200 miles from end to end). Roughly speaking, the wind speed at a particular site explains only 25% of the variability in wind speed at a different site (e.g., if $r = 0.5$, $r^2 = 0.25$).

We next converted the wind-speed data into estimates of hourly wind output (MWh) using typical turbine power curves (Fig. 5). At low wind speeds, below about 5 m/s, the turbine produces no power. Similarly, at very high wind speeds, above about 25 m/s, the turbine blades stop rotating to prevent damage to the blades. Between these lower and upper limits, power output varies nonlinearly with wind speed.* Roughly speaking, wind output is proportional to the cube of wind speed (WS^3) between the cut-in wind speed and rated turbine capacity.

*In reality, power output is a complicated function of several other factors, not just wind speed. These other factors include local topography, altitude, air density, and temperature.

Table 2. Correlation coefficients (*r*) of hourly wind speed among five sites from May 1997 through April 1998

	Site 2	Site 3	Site 4	Site 5
Site 1	0.48	0.64	0.45	0.34
Site 2		0.54	0.46	0.33
Site 3			0.41	0.36
Site 4				0.33

We simulated outputs from 200-MW wind farms located at these five sites. The results are similar across the sites. The capacity factors for these wind farms range from 32 to 35% and the CoV of the hourly wind output (ratio of average to maximum output) ranges from 80 to 86%.

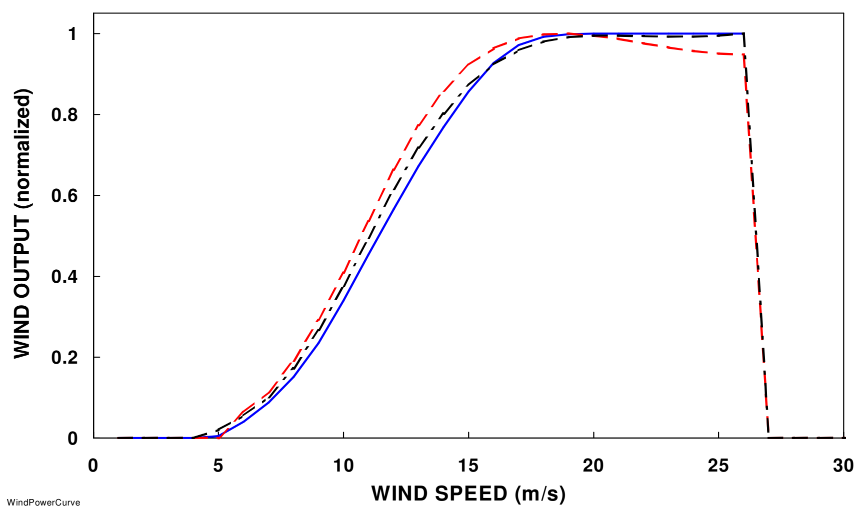


Fig. 5. Relationship between wind speed and wind output (normalized to the rated capacity of the turbine) for three different turbines.

To simulate larger and larger amounts of wind capacity within the service area, we assigned increasing amounts of turbine capacity to each of the five wind sites. If aggregate wind capacity is 200 MW, it is all located at one site, 400 MW is spread across two sites, 1,000 MW across three sites, 2,000 MW across four sites, and 5,000 MW across all five sites.[*]

As more wind farms are added at different locations throughout the service area, the aggregate variability of hourly output declines (Fig. 6). For example, the CoV declines from 0.86 for a 200-MW wind farm at one site to 0.60 for 1000-MW wind farms at four sites.

[*] We did not diversify the wind output within the five sites because the hourly outputs from the various turbines at a particular site are likely to be highly correlated (Hudson, Kirby, and Wan 2001; Starcher 2003). With an average wind speed of 8 m/s and an assumed turbine density of 10 MW/square mile, it would take the wind about half an hour to traverse a 1,000-MW wind farm and only 10 minutes to traverse a 100-MW wind farm.

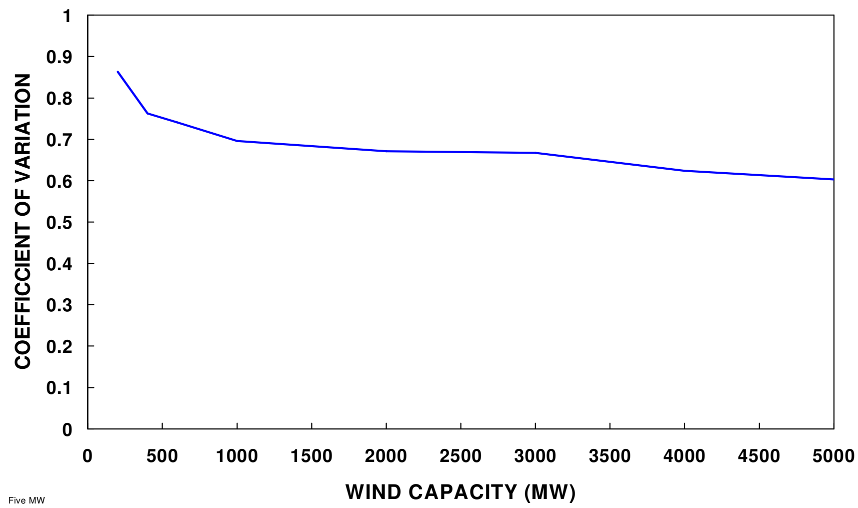


Fig. 6. Coefficient of variation of hourly wind output as a function of wind capacity in the utility area.

The benefits of geographical dispersion of wind farms is also evident on a smaller time scale. Figure 7 shows the correlations among hourly wind output from one hour to subsequent hours, ranging from one to 24 hours. As expected, the persistence of wind output drops rapidly. For the 1,000-MW wind farm, for example, the correlation coefficient between adjacent hours is 0.92, which means that the output in one hour predicts the output in the following hour with an 85% accuracy. On the other hand, a 12-hour lag reduces the correlation coefficient to only 0.28, which means that the output in hour *t* explains only 8% of the variation in output 12 hours later. Here, too, the correlation coefficients increase with greater geographical dispersion.*

FORECASTING WIND OUTPUT

Day-ahead forecasts of hourly wind output are important inputs to the unit-commitment process. Errors in the forecast can cause complications in real time. For example, if the forecast for a particular hour is 250 MW and the actual output that hour is only 150 MW, the deficit must be made up with other generating resources that are already online or can be turned on quickly. Alternatively, if the actual output is 350 MW, units online will have to be ramped down or, in extreme cases, shut down to accommodate the extra 100 MW of wind output. These sudden and unanticipated movements in other generators impose costs on the electrical system. In extreme cases (very large wind farms or highly inaccurate forecasts), the fleet of generating units may not have sufficient ramping (MW/minute), quick-start, or aggregate operating-range (MW) capability to respond adequately to the discrepancy between the DA schedule and actual wind output, leading to reliability problems.

Two methods are used to predict the output of wind farms: persistence models and meteorological models (Milligan 2001). Persistence models use the actual output of a wind farm for one or more hours to predict the output during a future hour. As shown in Fig. 7, these

*Milligan and Factor (2000) examined data from 12 wind-monitoring stations in Iowa to "find the best way to distribute wind-generating capacity among several sites by using an electricity-production, cost and reliability model." They, like the present study, found substantial benefits to geographical dispersion of wind farms.

models are quite accurate in predicting output one or two hours ahead, but are worthless in predicting output a day ahead. Because this project focuses on the DA UC, which requires estimates of expected wind output 12 to 36 hours in the future, persistence models were not considered.

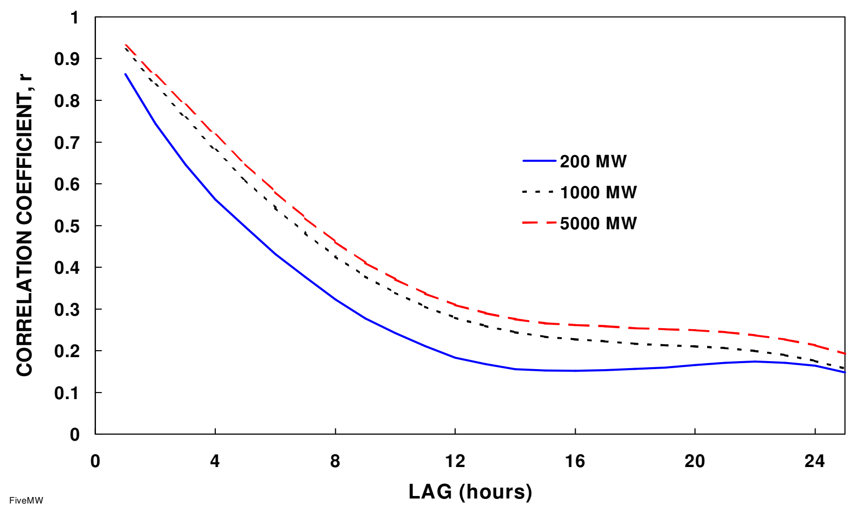


Fig. 7. Correlation coefficients of hourly wind output for lag times ranging from one to 24 hours as a function of wind-farm capacity.

Meteorological models use forecasts of weather conditions (temperature, humidity, cloud cover, etc) to first predict wind speed. These wind-speed predictions are then used to predict energy output. Because development of such a meteorological model was well beyond the scope of this project and likely to be an expensive and complicated undertaking, we chose a much simpler approach to approximate a DA forecast of hourly wind output.

We forecast wind output for hour *t* as the weighted sum of the average output for the prior day (averaged over the 24-hour period) and the actual wind output for hour *t*:

$$\text{Forecast (MW)}_t = \text{WF} \times \text{Actual (MW)}_{\text{prior day}} + (1 - \text{WF}) \times \text{Actual (MW)}_t \,.$$

The weighting factor (WF) is adjusted to produce an average forecast error consistent with today's wind-forecasting models and results. Conversations with a few wind-forecasting experts suggest that typical DA wind forecasts have errors that average 40 to 63% of the actual wind output (TrueWind Solutions 2003).[*] Setting WF to 0.67 yields an average forecast error of 50% for the 200-MW wind farm. As expected, the forecast error declines with increasing wind capacity, from 44% for 400 MW to 40% for 1,000 MW and 34% for 5,000 MW.

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[*]The TrueWind website includes this statement about the company's eWind forecasting method: "For next-day forecasts (12 hours and beyond), the MAE [mean absolute error] typically ranges from 14% to 22% … ." Given a capacity factor of 35%, these errors translate to the 40 to 63% noted above. The MAE is:

$$[1/(n \times MW)] \sum \text{Abs}(\text{Forecast} - \text{Actual})$$

where Forecast and Actual refer to the DA forecast and RT values of hourly wind energy, n is the number of hourly observations, and MW is the capacity of the wind farm.

Just as the hourly system load and wind output are entirely uncorrelated, so too are the forecast errors. Because these errors are uncorrelated, the addition of wind output to the system has a smaller effect on total error than would occur if the forecasts were correlated.

Addition of the 200-MW wind farm has virtually no effect on DA forecast errors. The 1,000-MW wind farm increases the 90% range of errors by about 270 MW, and the 2,000-MW wind farm increases this range by almost 1,000 MW. As more and more wind capacity is added to the system, the errors in the wind forecast begin to dominate the total forecast error (Table 3).

On the other hand, the benefits of the diversity between the load and wind forecast errors are greatly diminished for large wind farms. For the 2000-MW wind farm, the wind-forecast error dominates the load-forecast error (258 v 102 MW) and, therefore, dominates the overall error (272 MW).

Table 3. Day-ahead forecast errors for load, wind output, and the sum of load minus wind (MW)

		200-MW Wind		400-MW Wind		1000-MW Wind		2000-MW Wind	
	Load forecast error	Wind error	Load − Wind error	Wind error	Load − Wind error	Wind error	Load − Wind error	Wind error	Load − Wind error
Average of absolute values	102	33	105	57	115	132	164	258	272
5% value	-353	-93	-354	-168	-379	-408	-531	-805	-873
95% value	400	96	395	167	401	406	492	791	873
Standard deviation[a]	141	41	142	72	152	167	211	327	346

[a]Comparing the standard deviation (σ) of Load − Wind error with $\sqrt{(\sigma^2_{Load} + \sigma^2_{Wind})}$ shows that the two error components are essentially independent.

DAY-AHEAD UNIT COMMITMENT AND HOURLY DISPATCH

The utility's UC analysis is based on the current and expected status of each generating unit (online, offline and available, or unavailable), current spot prices for coal and natural gas, and expected market prices for electricity. These market-price expectations are used to estimate short-term purchases or sales. For example, if spot prices are expected to be lower than the variable costs of the utility's generators needed to meet native load and contractual requirements, the UC model will decrease the outputs of these generators and make offsystem purchases. These purchases and sales are limited by the available transmission capacity between the utility and its neighbors. In addition to inputs on generation and wholesale-market conditions, the model receives the DA forecast of hourly loads.

The model then calculates, as explained in Chapter 1, the least-cost mix of generating units, power purchases, and power sales to meet expected hourly loads. The model outputs include projected hourly costs: startup, fuel and variable O&M, and external purchases minus external sales (all in $/hour), as well as system lambda (in $/MWh). Figure 8 shows the model outputs for one summer day; clearly fuel dominates production costs. Most of these DA costs are projections; only some of the startup costs are real. However, some of the DA startup costs, especially for the combustion turbines, are estimates also. The hourly pattern follows closely the pattern of loads, which also peaks in the afternoon. The same is true for system lambda, which reaches its minimum values early in the morning and peaks in the late afternoon.

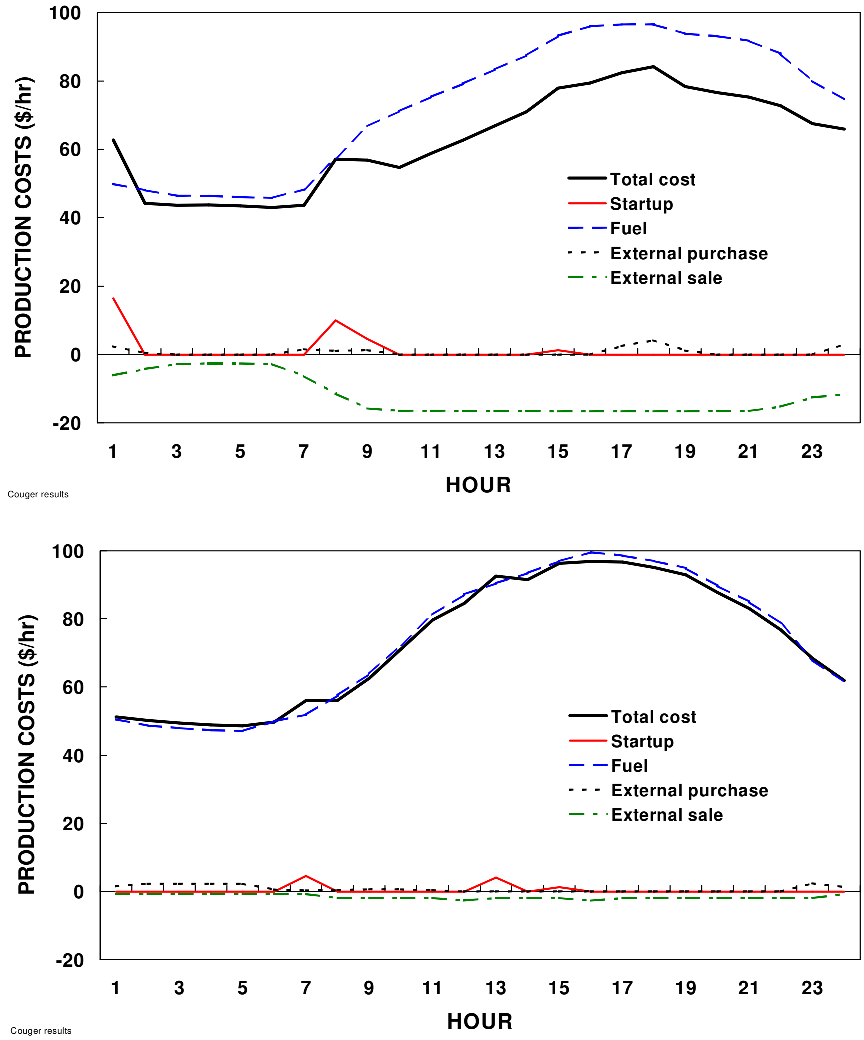

Fig. 8. Model results showing production costs from the DA unit-commitment run (top) and RT dispatch run (bottom) for one summer day.

After the operating day is over, the model is rerun to perform an ex post analysis of actual operations and production costs. Unlike the UC run, the dispatch run has available only those units already online or that can start quickly.

The DA and RT model runs also differ in their treatment of short-term purchases and sales. Day ahead, these are treated as discretionary and, therefore, are permitted to set system lambda. In real time, however, these purchases and sales are fixed throughout the operating hour. Because they are not permitted to vary during the hour, they are nondispatchable and therefore inframarginal. Because of these differences in the treatment of purchases and sales, DA values of lambda are consistently higher than the RT values. The difference between the DA and RT monthly values ranged from $0.5 to $4/MWh across the three analysis months. In a well functioning competitive market, these two sets of marginal costs (or market prices) should converge.

We dealt with this anomaly by adjusting the hourly DA lambdas *down* and the hourly RT lambdas *up* by one-half the difference in the monthly averages. This adjustment, conducted separately for each month and wind scenario, ensures that, on average, the DA and RT lambdas are equal.

The RT costs, unlike the DA estimates, are all real. However, some of the RT startup costs might duplicate costs from the DA UC run, in particular if a unit is started later in the day than the DA run anticipated. These ambiguities in startup costs, likely, have little effect on wind payments because startup costs are small (Fig. 8).

If the amount of generating capacity committed DA is insufficient to meet the RT requirements (either because the actual load is higher than forecast or the wind output is less than forecast), the model records a violation (usually, a deficiency in contingency reserves). To permit the model to create a solution, this deficit is modeled as an emergency purchase with a price of $100/MWh. Conversely, if the amount of capacity committed exceeds that needed in real time, any excess energy has an implicit price of zero and is recorded as an excess-energy violation.

In analyzing cases with various amounts of wind capacity, the DA analyses are adjusted for the expected hourly production from the wind farms. And the RT analyses are adjusted for the actual wind output. (This treatment of wind output is exactly the same, except with the sign reversed, as the treatment of system load.) Because wind, in both the DA and RT runs, displaces the most expensive thermal resources, the average and marginal production costs are lower with wind than without wind. However, differences between the DA schedules of wind output (based on the DA forecast of wind production) and actual wind output complicate this relationship. If the actual wind output differs materially from the DA schedule, the system operator will be required to operate the portfolio of available generation in a suboptimal fashion. For example, if the actual wind output exceeds the forecast, online generation will have to be backed down and operate less efficiently. In extreme cases, some units may have to be turned off prematurely, incurring nontrivial shutdown (and subsequent startup) costs. Analogous situations occur if the actual wind output is less than forecast.

The DA uncertainty about actual wind output during any particular hour raises a reliability issue. Should the wind-energy output be considered a firm or nonfirm schedule? For the winter and summer months, we ran the model twice, once treating wind as 100% nonfirm and a second time treating wind as 100% firm. If wind is considered nonfirm (i.e., economy energy), the model commits additional generation day ahead to back up the scheduled wind output on a MW-for-MW basis. This treatment raises production costs, which reduces the amount of money wind resources can be paid for their output. If the DA forecast of wind output is considered firm, the model assumes that amount of energy *will* be delivered the following day as scheduled. Thus, treating the wind as 100% firm could raise reliability problems in real time if enough other resources are not available to make up any deficit between wind's DA schedule and RT output. A middle ground, which would not bias results against wind, would consider some portion of the projected wind output firm and the remainder nonfirm. Analysis of the accuracy of the DA wind forecast and the variability of actual wind output could be used to decide how much wind to consider firm. Our results assume that 35% of the forecast wind output can be considered firm, consistent with the wind farms' capacity factors.

The model ignores some of the costs and constraints likely to occur with large amounts of wind capacity. These costs and constraints are associated with the rapid and frequent movement of conventional generating units to offset wind-forecast errors and intrahour changes in wind output. For example, large steam-generating units often have multiple boiler feedpumps, which control the flow of water to the boiler. As the unit's output is increased over the operating range, additional feedpumps are turned on; as the unit's output is decreased, these pumps are turned off. Manufacturer specifications limit the number of times a day these pumps can be turned on and off. Large amounts of wind capacity might cause the plant operator to violate these specifications, leading to premature failures and higher O&M and capital costs. Such factors are not considered in this model.

We used the cost and lambda results from the model to calculate the revenues that wind farms would receive two different ways. One approach, based on marginal costs (MC), mimics the operation of SMD-type DA and RT energy markets. The wind farm receives DA revenues equal to the product of the DA wind-output forecast for a particular hour multiplied by the DA lambda (λ) for that hour. In RT, the wind farm receives revenues (or pays the system operator) for the difference (energy imbalance) between the DA forecast and the actual value of wind output multiplied by the RT lambda:

$$\text{Wind Payment (\$)} = \lambda_{\text{DA unit commitment}} \times \text{MW}_{\text{DA Wind forecast}} + (\text{MW}_{\text{Wind actual}} - \text{MW}_{\text{DA Wind forecast}}) \times \lambda_{\text{RT dispatch}} .$$

The alternative approach, based on average costs (AC), pays wind for any operating-cost savings the system realizes. (In such cases, the wind farm receives all the benefits it provides; utility customers and shareholders receive no share of these gains.) The only DA costs that are real and not included in the RT costs are the startup costs (SUCost, although, as noted above, not all the DA startup costs are actually incurred). This method would pay wind:

$$\text{Wind Payment (\$)} = (\text{DA-SUCost} + \text{RTCost})_{\text{without-wind}} - (\text{DA-SUCost} + \text{RTCost})_{\text{with-wind}} .$$

The price wind would receive for its output in both cases is:

$$\text{Wind Price (\$/MWh)} = \text{Wind Payment/Wind Actual Output} .$$

INTRAHOUR BALANCING AND REGULATION

Integrating wind output with an electrical system involves three components: hourly energy, intrahour balancing, and regulation. The second and third components have no net energy associated with them at the hourly level. The prior section discussed the first element, the revenues a wind farm would receive for the energy it scheduled day-ahead and the energy it actually delivered hour by hour during the operating day. This section focuses on the charges a wind farm would face for the intrahour fluctuations of its output around its hourly actual—not scheduled—values.

During each operating hour, the system operator dispatches generation (and, perhaps, some load) 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 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.

Splitting Regulation from Intrahour Imbalance

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 within the hour.

We assume that the utility performs an economic dispatch every five minutes. Thus, we 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 9 shows the results, for one hour, of the method used to disaggregate system load and wind output into their regulation and intrahour-imbalance components. The average load for this hour was 4,200 MW, with the intrahour balancing component ranging from −34 to +26 MW. The regulation value ranged from −3.8 to +3.2 MW, with a standard deviation of 1.9 MW.

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*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.

The average wind output for this hour was 11 MW. Its imbalance ranged from −5.6 to +3.6 MW, and its regulation component ranged from −1.8 to +2.7 MW, with a standard deviation of 1.1 MW. Both components have zero energy on an hourly basis. The standard deviation of the 1-minute load is about 0.5% of the average load; the comparable value for wind output is 28%, which again shows how much more volatile the wind output is.

Imbalance Amounts and Charges

As shown in Fig. 9, the wind output varies during each hour, sometimes producing more power than its hourly average and other times producing less power. When wind overgenerates relative to its hourly average, the wind-farm owner is paid for this extra power on the basis of the interval lambda (λ_t, where t refers to one of the 12 5-minute intervals each hour). Similarly, when wind undergenerates, the owner must pay for the extra power it takes from the system at a price equal to the interval lambda.

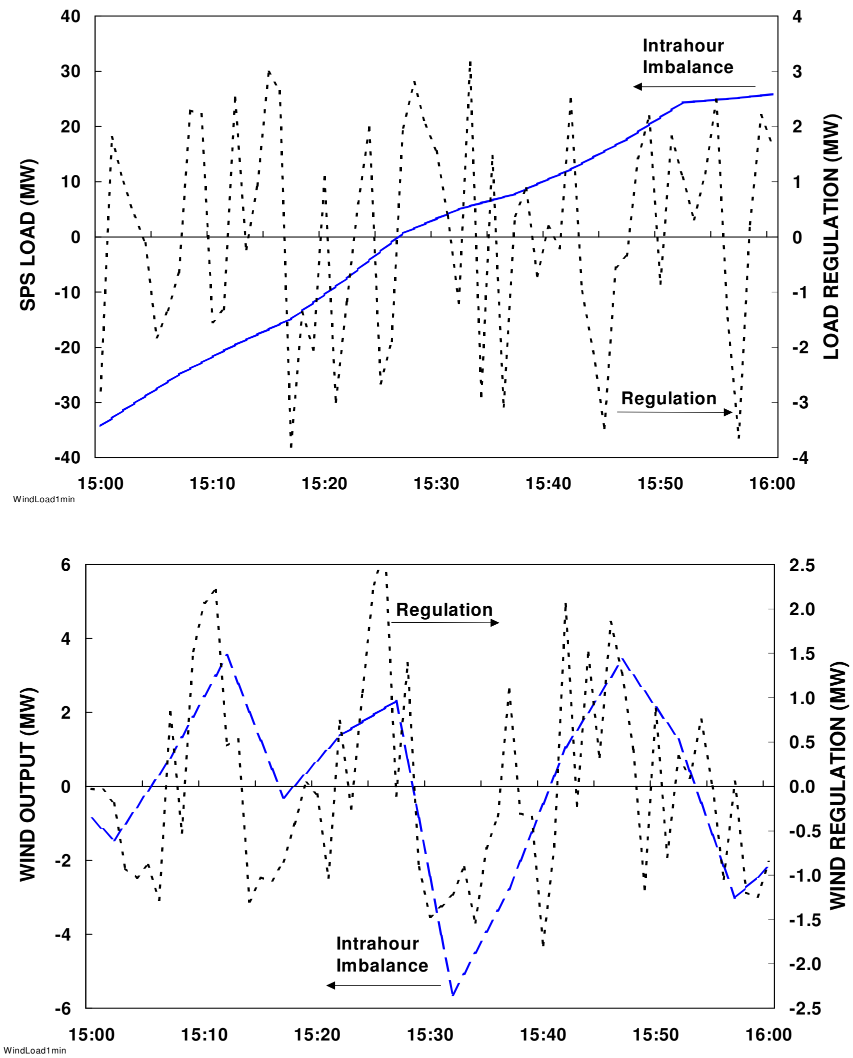

Fig. 9. Minute-by-minute variation in the intrahour imbalance (dashed) and regulation (dotted, right-hand axis) components of system load (top) and wind output (bottom).

We calculated system lambda on the basis of the hourly lambda and the current 5-minute (interval) imbalance. The current imbalance is equal to the 5-minute load imbalance plus the system-operator adjustment for the wind imbalance (discussed below). Multiplying the interval wind imbalance times the interval lambda yields the payment to (from) wind for over- (under-) generation. Summing these 12 values yields the hourly net payment for wind imbalance:

$$\text{Hourly payment to wind farm for intrahour imbalance} = \sum_{t=1}^{12} (\lambda_t \times \text{Imbalance}_{\text{Wind-t}}) ,$$

where Imbalance = $\text{WindMW}_t - \text{WindMW}_{hour}$.

The key issue is what, if anything, the control area does with this additional (relative to system load and the unscheduled movements of generators) source of imbalance. At one extreme, the system operator could ignore the intermittent wind output 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.

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 CPS1 and 2 requirements.

The method used here requires the system operator to deploy its regulation and intrahour-imbalance resources to maintain roughly the same CPS performance with wind as it did without wind. We adjusted the imbalance requirement as follows to maintain the same levels of performance for the week:

$$\text{Imbalance adjustment}_t \text{ (MW)} = -a\text{Wind}_{t-1} ,$$

where a is a user input 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. We 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.

Because the CPS criteria do not require perfect balancing of generation to load, the AGC systems in bulk-power control centers seek to manage—not minimize—ACE. We approximated these complicated algorithms with a very simple one to respond to wind variations. We assumed that the wind imbalance in one interval is responded to in the subsequent interval (although some response might occur in the interval the imbalance occurs through the regulation service). This response in the subsequent interval is made only if it reduces the absolute value of ACE; otherwise no response is made. New values of ACE, CPS1 and CPS2 are calculated based on the wind fluctuations and the system-operator responses to those fluctuations.

Interval lambda is calculated on the basis of the hourly lambda, that interval's imbalance, and the generation-supply curve. This supply curve, assumed to be time invariant, reflects the operating and cost characteristics of the utility's generating units. If the sum of interval load plus the wind-output adjustment is positive, the interval lambda will be higher than the hourly average because the system operator is acquiring imbalance energy for that interval. Thus, if wind is overgenerating at the same time that the load is above its hourly average, the wind farm will get paid for the excess energy at a price greater than the hourly average. Conversely, if wind is overgenerating when the load is lower than its hourly average, the price paid for this excess wind will be less than the hourly average lambda. The extent to which wind over- and under-generation results in hourly payments different from zero depends on the correlation between interval loads and wind output. If the two are highly correlated (i.e., wind output tends to increase when load increases), the wind farm will be paid for its intrahour variations in output. On the other hand, if wind output decreases when load increases (worsening ACE), the wind farm will be charged for its intrahour variations.

To simulate the imbalances associated with wind farms larger than the one now operating in this area, we set the magnitude of the intrahour interval movements equal to the energy wind multiplier to the 3/4 power (= $WM^{0.75}$). This factor fits well with the diversity benefits of larger and larger wind farms discussed in Chapter 3.

Allocation of Regulation Requirement

We 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 lines in Fig. 9) to define hourly regulation requirements. Regulation is defined as the hourly standard deviation of the 60 1-minute values of the fluctuations around the 5-minute imbalance values. We calculated these values each hour for load, wind, and for load minus wind. The minus sign is appropriate because load increases and wind decreases have the same effect on system ACE.

In the present situation, this method defaults to a simpler one because the regulation components of wind and system load are uncorrelated. In this simpler case, the total regulation requirement (σ_T, load minus wind) is equal to:

$$\sigma_T = \sqrt{(\sigma_{Load}^2 + \sigma_{Wind}^2)}\ .$$

And wind's share of the total is $(\sigma_{Wind}/\sigma_T)^2$.

To simulate the amounts of regulation required for wind farms larger than the one now operating in the utility's service area, we adjusted the magnitude of the wind regulation standard deviation by a factor equal to the energy wind multiplier to the ½ power (= $WM^{0.5}$). This ½ power is based on the assumption that the regulation components of multiple wind farms are independent of each other. Data on intrahour variations from four components of the

Lake Benton wind farm in southern Minnesota show such independence (Hudson, Kirby and Wan 2001).

To calculate the hourly charges a wind farm would face for regulation, we assumed that this utility requires 30 MW of generation assigned to the regulation service in the no-wind case.[*] We also assumed, based on data from the California ISO, New York ISO, PJM Interconnection, and ISO New England, that the average cost of regulation is about $30/MW-h. Finally, we assumed that this cost varies linearly with system lambda on an hourly basis.[#]

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[*]In practice, the amount of capacity on AGC varies by season, type of day, and perhaps hourly. Lacking data on these temporal variations, we assumed that the required amount of regulating capacity is fixed. The amount of generation control areas typically assign to AGC equals 1 to 1.5% of system load.

[#]Utility and ISO tariffs generally charge regulation costs to loads, not to generation. In principle, any entity responsible for regulation costs should pay its fair share of those costs (Kirby and Hirst 2000).

RESULTS

DAY-AHEAD UNIT COMMITMENT AND HOURLY DISPATCH

We used the UC model to analyze the payments a wind farm might receive for delivery of wind energy to the utility system for a spring/fall month, a summer month, and a winter month (Table 4). In all cases, we considered wind farms of 200, 400, 1,000, and 2,000 MW. We tried to analyze a 5,000-MW wind farm, but the portfolio of generating units could not accommodate the very large hour-to-hour load swings associated with so much wind capacity. The model, when run with large amounts of wind capacity, reports many excess-energy and reserve-shortfall violations. These violations show that the system cannot handle large changes in hour-to-hour loads net of wind generation. For the same reasons, we were unable to run 2,000 MW of wind for the spring month, probably because fewer resources are online and available during this nonpeak period.

The model runs showed *no* violations with wind farms of 200 and 400 MW. The cases with 1,000 MW of wind capacity showed a few, usually small violations, while the cases with 2,000 MW of wind showed many more violations, often of large magnitude. As expected, the number of violations was much higher for RT dispatch than for DA UC. The model has many more generation resources available to it during the DA UC run than during the RT dispatch run because the long startup times for some steam units preclude them from being used in real time unless they were scheduled day ahead. As a consequence, violations are more likely to occur in the RT analysis than in the DA analysis.

The average and peak loads were highest in summer and lowest in winter. The intraday load swings (the difference between the highest and lowest hourly loads each day) were high in spring (670 MW) and summer (950 MW), and much lower in winter (350 MW). The large load swings in spring complicated the integration of large amounts of wind because the amount of capacity online and available that month was much lower than during the summer months. The large changes from day to day in spring load swings complicated DA UC and hourly dispatch.

Table 4. Key load, cost, and wind characteristics for months analyzed with the unit-commitment model

	Spring	Summer	Winter
Average load, MW	3,000	3,600	2,700
Peak load, MW	4,000	4,600	3,100
Intraday load swing/ Average load[a]	0.25	0.29	0.14
	Production costs, $/MWh		
DA Lambda	30.3	31.4	35.3
RT Lambda	26.3	28.8	34.7
RT average cost	21.0	21.3	22.2

[a]The intraday load swing is the difference between the highest and lowest hourly load for a particular day.

As the amount of wind capacity increases, the payment to wind, per MWh of wind energy, decreases (Fig. 10). (We are unsure what causes the spike in the average-cost payment for a 200-MW wind farm in winter. In our summary, we ignore this result.) For very small amounts of wind, the average- and marginal-cost payments are close to the values of lambda for each month. At the other end of the spectrum, the payments to a 2,000-MW wind farm would be $0 in spring, $10 to $18/MWh in summer, and $8 to $10/MWh in winter.

The payments per MWh of wind output vary from day to day as a function of wind- and load-forecast accuracy and correlation, hourly values of lambda, and where on the supply curve the system is each hour (Fig. 11). The daily averages show clearly the reduction in payments as the amount of wind capacity increases. With 2,000 MW of wind capacity, the payments are sometimes negative.[*] In addition, the volatility of the day-to-day payments generally increases for larger wind farms.

[*]On one summer day, the DA and RT lambdas averaged $7 and $17/MWh, respectively, with 2000-MW of wind capacity. The average forecast of wind output for that day was 861 MW, more than double the actual output of 383 MW. So wind received a very small payment for its DA schedule and was then required to buy back its deficit in real time at a much higher price.

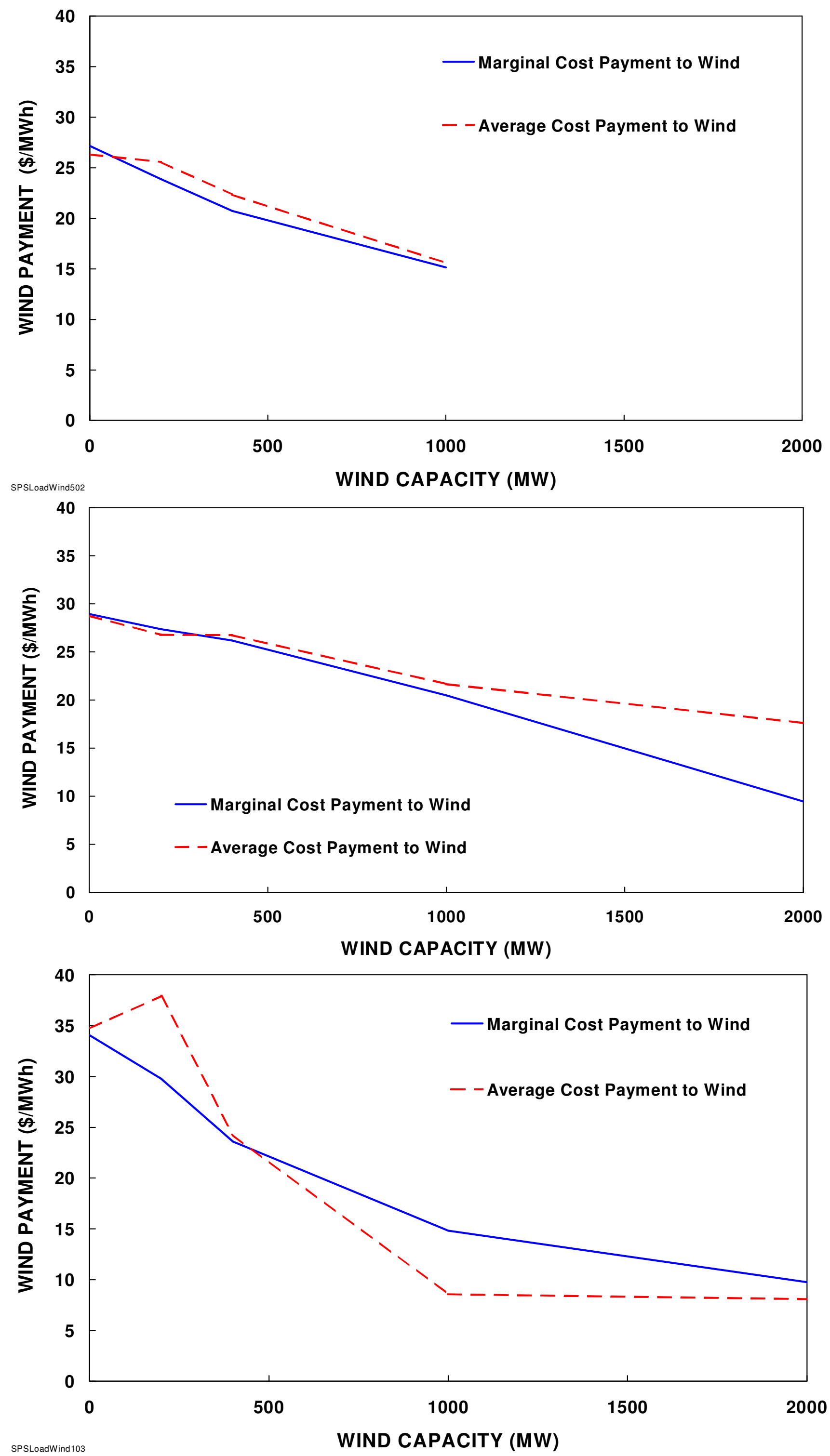

Fig. 10. **Marginal-cost and average-cost payments to wind farms for nonfirm hourly energy as a function of wind capacity for spring (top), summer (middle), and winter (bottom).**

The very high payments to wind on one winter day are a consequence of two factors: (1) DA lambdas were much higher than RT lambdas, especially from noon on ($50 v $23/MWh for these 12 hours), and (2) actual wind output was much less than forecast (39 v 75 MW for the 200-MW wind farm). As consequence, wind was paid a high price for its forecast output DA and repaid the system for the RT deficit at a much lower price. The fact that the RT output (the denominator in this factor) was only one-third the forecast output exaggerated this effect.

To examine the additional payments a wind farm might receive if its output could be considered firm, we reran the cases for winter and summer assuming the wind output was 100% firm. As expected, the marginal-cost results showed higher payments, increasing with greater wind capacity (Fig. 12); the average-cost results were erratic, sometimes showing *lower* payments for 100% firm wind. These results show modest benefits for large wind farms if the wind output can be considered firm. The summary results shown later in this chapter assume that 35% of the DA wind output is firm. This adjustment adds $1.4/MWh for the output from a 1000-MW wind farm.

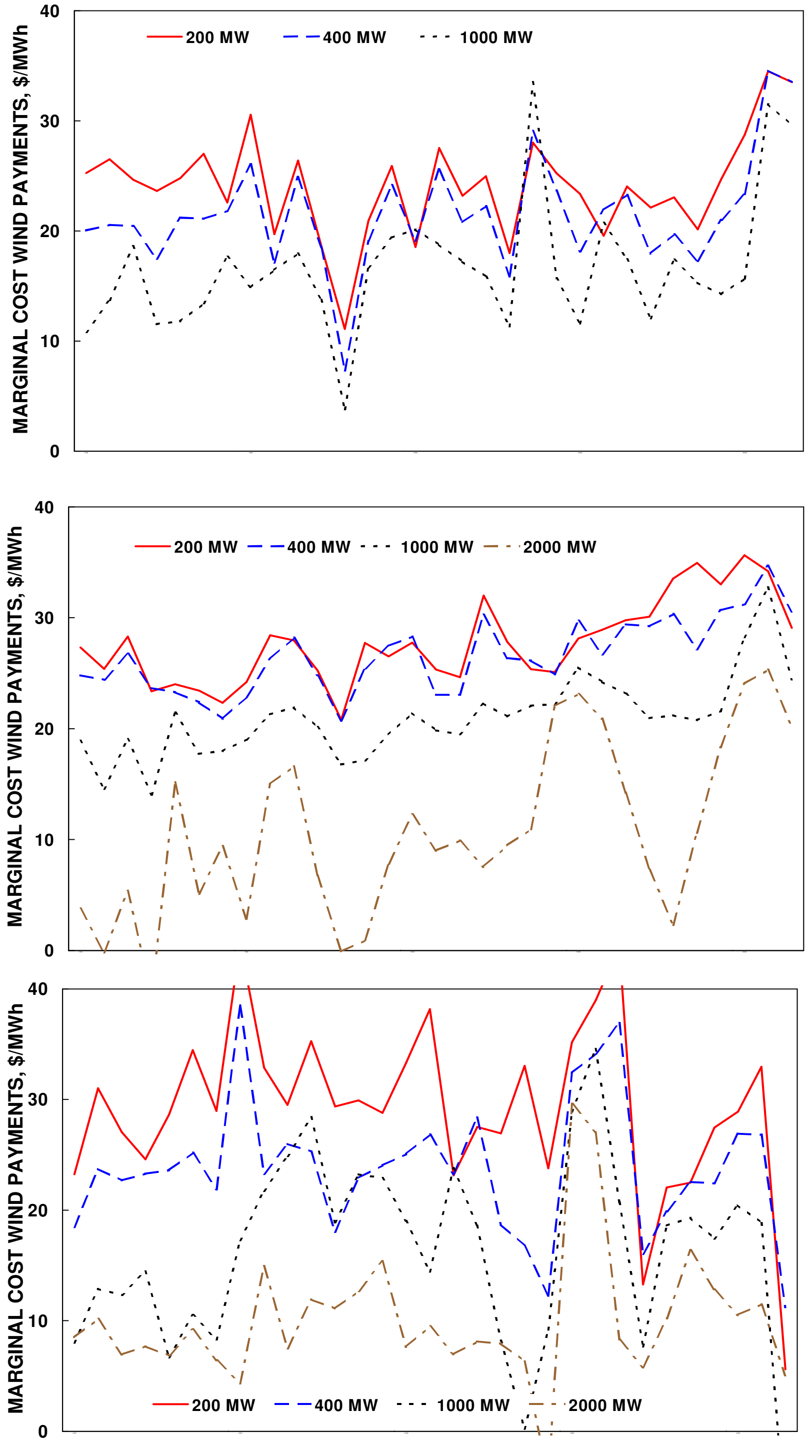

Fig. 11. Marginal-cost payments for nonfirm wind, day by day, as a function of wind capacity for spring (top), summer (middle), and winter (bottom).

The 1-minute data cover two 1-week periods in spring and summer (Table 5). Lower natural gas prices in summer explain much of this difference. The CoV values show how much more variable wind output is, relative to its average value, than is system load. On the other hand, wind output and load, for both intrahour imbalance and regulation, are uncorrelated with each other.

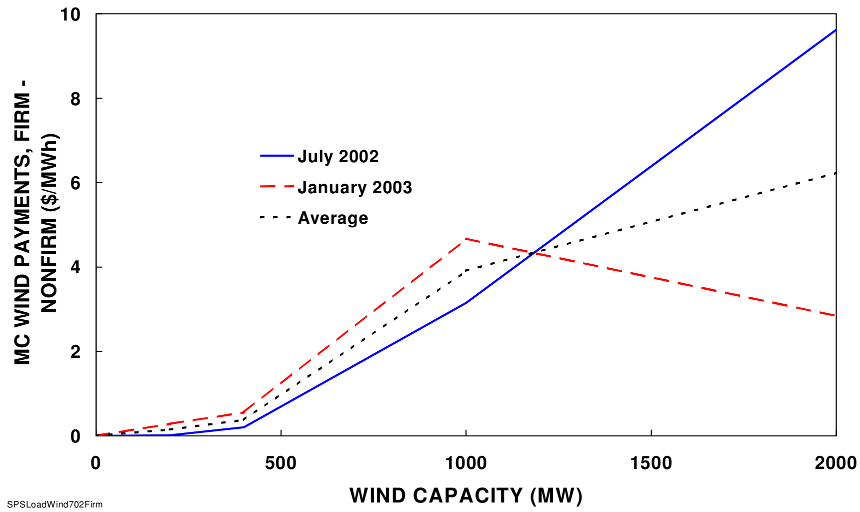

Fig. 12. Incremental payments for 100% firm (v 100% nonfirm) wind energy as a function of wind-farm capacity for summer and winter.

Table 5. Summary statistics on load and wind output for two 1-week periods

	Spring		Summer	
	Average	CoV[a]	Average	CoV[a]
Load, MW	3260	0.11	4070	0.11
Wind, MW	42.0	0.72	27.7	0.65
Lambda, $/MWh	44.9	0.20	38.0	0.24
Correlation coefficients				
Load:Wind	0.02		−0.12	
Regulation components	0.01		0.01	
CPS1, %	203		194	
CPS2, %	99.9		99.9	

[a]CoV is the coefficient of variation, the ratio of standard deviation to the mean.

The CPS performance was outstanding. For example, CPS2 was very close to its maximum potential value of 100% for both weeks.

The patterns of energy use and LF for system load are consistent from day to day. In contrast, the wind output displays no such consistency. The regulation components for both wind and load show the expected random variations. The regulation and load-following components of wind are equivalent to 1.6% and 21% of average wind output, compared with 0.1% and 2% for system load.

For a 1,000-MW wind farm, intrahour balancing would cost $0.01/MWh (1¢/MWh) of wind output. What accounts for this remarkably small charge, given the large volatility in wind output?

First, there is essentially no correlation between the intrahour balancing components of system load and wind output. That is, intrahour changes in wind output are equally likely to offset or worsen variations in system load. Because of the lack of correlation between these two factors, the average of the absolute value of the combined imbalance is only 29 MW, much less than the 37-MW sum of the two components.

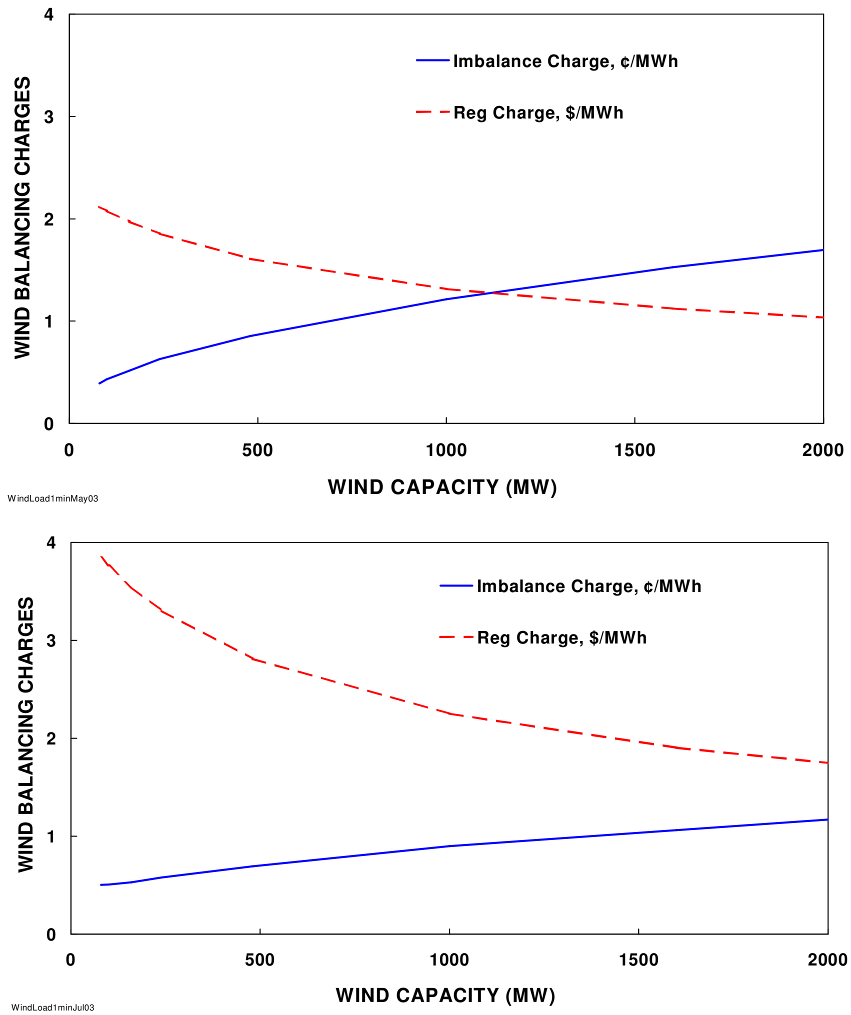

Fig. 13. Regulation and imbalance charges as a function of wind-farm size for spring (top) and summer (bottom).

Second, the price changes associated with the system-operator adjustments to maintain CPS performance in the face of wind volatility are very small. For the spring week, the average difference between the highest and lowest interval price each hour is about $1/MWh for the case with a 1,000-MW wind farm.

Figure 13 shows how these de minimus charges for intrahour balancing vary with the capacity of the wind farm. Even for a 2,000-MW wind farm, the charge is only a penny or two per MWh of wind output.

Figure 13 also shows the charges to wind for the regulation service. These charges, while also modest, are substantially higher than those for intrahour balancing. A 2,000-MW wind farm, for example, might pay one to two dollars per MWh of wind output for regulation. A 100-MW wind farm would pay twice as much, two to four dollars per MWh.

Just as the costs of intrahour balancing and regulation vary with the amount of wind capacity, so too do the associated amounts of generating capacity that provide these services. The patterns of changing MW amounts is similar for the two weeks in spring and summer (as was true for the dollar charges). The regulation requirement for wind farms increases much more slowly than does the amount of wind capacity, based on the assumption that the 1-minute fluctuations in wind output among the turbines at a single wind farm and among wind farms are uncorrelated. The average capacity requirement to meet the incremental wind imbalance is about 1% of the wind-farm capacity. However, the capacity requirement needed to accommodate 95% of the maximum incremental hourly imbalance associated with wind increases faster than wind capacity, reaching 3 to 5% for a 1,000-MW wind farm.

In summary, analyses of 1-minute data for two 1-week periods in spring and summer lead to the same findings. The charges for intrahour balancing are very small, a few cents per MWh of wind output. The charges for regulation are two orders of magnitude greater, one to three dollars per MWh. The regulation charges calculated here are about ten times higher than those found in earlier projects that involved integration of wind output with the PJM or Bonneville Power Administration systems (Hirst 2001b and 2002). This difference is probably a consequence of the fact that the PJM and Bonneville systems are much larger than the system.

Other studies obtained results similar to those presented here. The Utility Wind Interest Group (2003) reviewed several analyses that show intrahour charges ranging from \$0.5 to \$3/MWh of wind output, for wind farms up to about 20% of peak load. The Bonneville Power Administration offers a Network Wind Integration Service to public-power customers inside its control area (Mainzer 2003). Wind will be treated as a negative load with a balancing charge of \$4.50/MWh.

NET PAYMENTS TO WIND

The net payments to a wind farm are equal to the hourly energy payments based on the results presented in the first section of this chapter minus the charges for regulation and intrahour balancing presented in the preceding section.

On an annual average basis, the energy payments to wind farms decline from \$32/MWh for very small farms to \$25/MWh for 400 MW of wind capacity, and less than \$10/MWh for wind farms larger than 2,000 MW.[*] The close agreement between the average- and marginal-cost results is encouraging; it lends credibility to these answers.

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[*]We are not sure how much of the reduction in payments for hourly energy is caused by the addition of any zero-variable-cost resource and how much by errors in the DA wind forecast and *inter*hour changes in wind output.

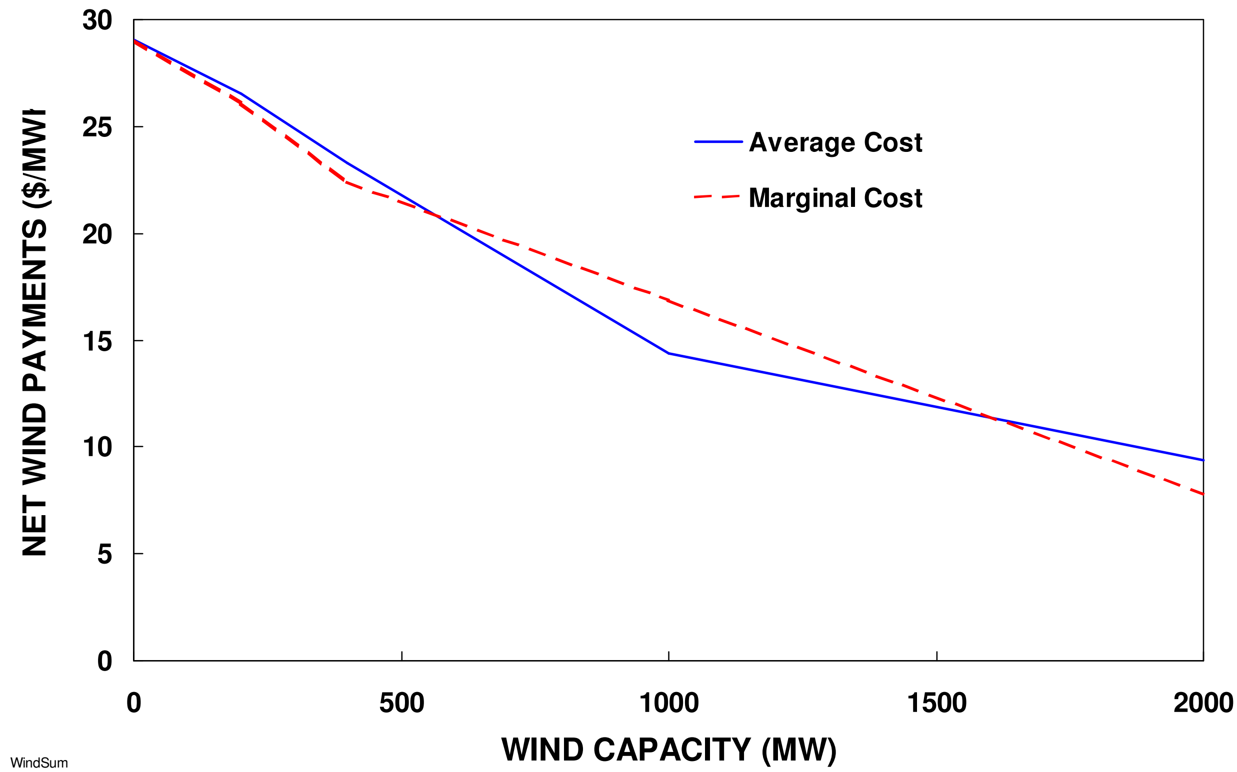

Fig. 14. **Net payments for wind energy (payments for hourly energy minus charges for intrahour balancing and regulation) as a function of wind capacity.**

Figure 14 begins with the energy payments discussed above and subtracts the intrahour charges to arrive at the maximum net payments to wind farms as a function of wind capacity. Clearly, the amount of money that can be paid for wind energy depends strongly on how much wind capacity is installed within the service area. For very small amounts of wind, the payment is almost $30/MWh. However, as the amount of capacity increases, the payment decreases. For 1,000 MW of wind the payment is 50% less, $15/MWh. And for 2,000 MW of wind, the payment drops to about $8/MWh, in large part because the payment is zero for the spring and fall months. The decline in payments per MWh of wind energy are a consequence of several factors:

- The addition of any new generation capacity to a small utility system;
- Errors in the DA forecast of wind output, which create RT costs to adjust the outputs of conventional generating units;
- Interhour variability in wind output;
- Intrahour energy imbalance (load following); and
- Regulation.

CONCLUSIONS

Dragoon and Milligan (2003) state that "Confidence in the ability to capture the value of wind generation on modern power systems is crucial to the further development of wind resources in the United States. Without a clear framework for estimating wind integration costs, it is unlikely that regulated utilities will be able to make convincing arguments before utility regulatory bodies." In addition, RTO-operated competitive wholesale markets require clear rules so that costs and benefits are appropriately assigned to those parties responsible for those costs and benefits.

The method developed and applied here to various amounts of wind capacity that might be installed in the service area provides the framework and results suggested by Dragoon and Milligan.* Our method analyzes and quantifies the revenues and charges a wind farm would face for DA UC, RT hourly dispatch, intrahour load balancing, and regulation. The method relies on detailed (hourly and 1-minute) data from the utility and the wind farms.

Although these results should be quite useful to wind developers, power marketers, and utilities, they are based on limited data and many assumptions. Therefore, these results should be considered suggestive rather than definitive.

Some of the key limitations in this study include:

- Only limited time periods were analyzed. Specifically, we analyzed payments for wind energy for three months. We would have more confidence in the numerical results had a full year of data been available. Additional data would have permitted analysis of payments and charges to wind over all seasons and perhaps across periods with different coal and natural gas fuel prices.

- The "data" on wind output are simulations, based on hourly wind speeds from five locations within the utility area. In addition, these data on wind speed are for a different

*This method expands upon previous work. Hirst (2001) did not consider DA UC. Electrotek Concepts (2003b) did not analyze intrahour data; therefore, their estimates of LF and regulation are speculative. Dragoon and Milligan (2003) calculated the balancing costs of wind based on the difference between the operating costs with wind and those with a resource that produced the same amount of energy at a constant level, hour by hour, throughout that year; we question the relevance of this comparison. And several studies analyzed only small amounts of wind capacity in large systems (see Electrotek Concepts 2003a, Kirby et al. 2003, Hirst 2001b, and Hirst 2002).

period (1997 to 1998) than are the UC-model results (2002 to 2003) and the 1-minute data on regulation and intrahour balancing. The lack of correlation between load and wind output and between system lambda and wind output lend confidence to our use of data from different times.

- The results for intrahour balancing and regulation are based on very limited data: 1-minute observations for two 1-week periods. The scaling factors we used (0.75 for intrahour balancing and 0.5 for regulation) to estimate these costs of intrahour integration for larger wind farms (up to 2,000 MW, more than 20 times larger than the operating wind farm) are based more on judgment than on data.

- Because the treatment of power purchases and sales in the DA unit-commitment and RT dispatch runs was different, the DA values of lambda were consistently higher than the RT values. Our adjustment of hourly values of lambda is approximate in its effort to eliminate any bias associated with wind-forecast errors.

- The assumption, day ahead, that the wind output was 35% firm assumes that the capacity factor of the wind farms is a good proxy for the wind forecast accuracy. Additional work is needed to develop a method to determine how much of the DA wind schedule can be considered firm and how much nonfirm.

- For several reasons, the results are increasingly speculative as the capacity of wind farms increases. (1) Our analyses of LF and regulation is based on data from one wind farm, with assumed scaling factors used to adjust these quantities for larger wind farms. Extrapolating from less than 100 to 2,000 MW is a stretch. (2) The number of model violations increases with wind-farm capacity. There were no violations for 200 and 400 MW of wind; however, the number and severity of violations increased sharply between 1,000 and 2,000 MW. (3) The volatility of model results increases with wind-farm capacity (Figs. 11 and 12), suggesting that these results are less stable than those for smaller wind farms. (4) The model does not incorporate all the fuel, O&M, and capital-additions costs associated with the rapid and frequent movement of generators that would be required with large wind farms in a small electrical system. Roughly speaking, we believe the present results are valid up to about 1,000 MW;* beyond that point, the results are both speculative and likely to underestimate the full costs of wind integration with the system.

- These results depend on the geographic dispersion of the wind farms. Locating wind farms on fewer sites would lower payments to wind farms, while expanding the number and diversity of sites would increase payments.

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*Because of transmission constraints, both within this utility and between it and its neighbors, the present results may be valid for less wind capacity.

These limitations suggest additional efforts to improve the accuracy of these results:

- Calculate results for at least a full year.

- Analyze the benefits of improved DA wind-forecast accuracy. The results of such analyses will show how much of the wind can be considered firm (v nonfirm) and how improved accuracy reduces the magnitude and costs of RT adjustments for forecast errors. One could run the DA UC model with actual wind output to simulate the benefits of a 100% accurate wind forecast, which would provide an upper limit on the value of improved forecasts.

- Analyze the potential benefits of new wind-turbine designs and taller wind towers. In particular, such designs might have higher capacity factors and less hour-to-hour variability in output, both of which would lower integration costs per MWh of wind energy.

- Analyze the possible need for wind to pay for contingency (spinning and supplemental) reserves. Are the costs of these reserves implicitly captured in the DA and RT model runs, or do they represent additional costs that wind should pay for?

- Analyze the long-term (10 to 20 year) impact of adding large amounts of wind capacity to a utility system. The present analyses assumed no changes in the utility's amount and mix of generation and added no new transmission. Over time, as loads grow and old, inefficient generating units are retired, a utility will invest in new generation and transmission. If some of the new generation is wind, the mix of the other generation and the transmission investments might be different.

- The transmission issues associated with the remote locations of most wind farms deserve much more attention. For example, this study did not analyze the need to uneconomically redispatch generation to relieve transmission constraints caused by building wind farms at poor locations on the transmission grid.

In spite of the limitations listed above, we believe the present results are valuable and roughly representative of what would occur with a more comprehensive analysis. These results show clearly that modest amounts of wind receive payments (net of charges for regulation and intrahour balancing) almost equal to system lambda. The integration costs are low because the correlations between wind output and system load, as well as their forecast errors, are very low. However, as the amount of wind capacity installed in an area increases, the payment drops. Although adding wind farms throughout a region increases the diversity of the wind output and improves the accuracy of the DA wind forecasts, the payments decline. This drop occurs because each increment of wind energy pushes the existing conventional generation to lower levels on the supply curve, with lower marginal costs. Also, the more wind that is added to a system, the more the conventional generation must move up and down, both intra- and inter-hour, to adjust for the lack of control, unpredictability, and variability of wind output.

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