May 2003 • NREL/CP-500-34022

Conference Paper

Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp

Preprint

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To be presented at WINDPOWER 2003
Austin, Texas
May 18-21, 2003

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ASSESSING WIND INTEGRATION COSTS WITH DISPATCH MODELS: A CASE STUDY OF PACIFICORP

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ABSTRACT

Conventional electric production simulation models do not fully capture the unique issues surrounding wind power plants. PacifiCorp used an hourly system dispatch model to estimate wind resource integration costs in its Integrated Resource Plan (IRP). This paper explores a number of modeling issues surrounding the representation of wind integration costs in dispatch models and the implications for calculating wind integration costs. Such issues include unit commitment logic, reserve requirement calculations, and wind forecast accuracy. We also discuss methods of assessing integration costs outside the conventional modeling framework, and we present some wind-related results from the PacifiCorp IRP. We believe that this paper will be of value for utilities and control areas that are involved in assessing potential wind impacts and integration cost and will help provide a framework for future model development. These modeling issues need to be addressed by the modeling community as wind becomes a significant part of utility resource portfolios.

INTRODUCTION

Integrating wind energy into complex power system is expected to incur system costs in excess of system costs incurred by equivalent amounts of energy delivered to the system on firm, fixed schedules. Those additional costs must be estimated to understand the relative value of wind energy compared with other resources. Deterministic and stochastic dispatch models are generally available and useful in determining the value of resource portfolio additions. However, the variable) output of wind resources and wind forecasting errors introduce complexities that are difficult to capture in commercially available dispatch models. This paper explores some of the issues involved in valuing wind projects with generally available dispatch modeling capability.

PACIFICORP'S APPROACH

PacifiCorp currently purchases 83 MW of wind energy from wind resources located in Wyoming. In addition, PacifiCorp provides integration services for more than 200 MW of wind power from projects located in Wyoming and along the eastern Oregon/Washington border. PacifiCorp needed to analyze the comparative value of wind projects in its 2003 Integrated Resource Plan (IRP). The analysis was performed with public input, including suggestions and comments from a number of industry experts. The resulting valuation contributed to PacifiCorp's conclusion that some 1,400 MW of additional wind capability are a component of a least-cost-mix portfolio of resources [1].

Utility operation spans several time scales, as illustrated in Figure 1. The unit-commitment time scale typically covers several hours to days ahead. In this time frame, decisions must be made on which generating units to start so that they are available when needed. The unit-commitment decision must be made well in advance of the time the generator might be needed because of the relatively long time required to start and stop some types of generators.

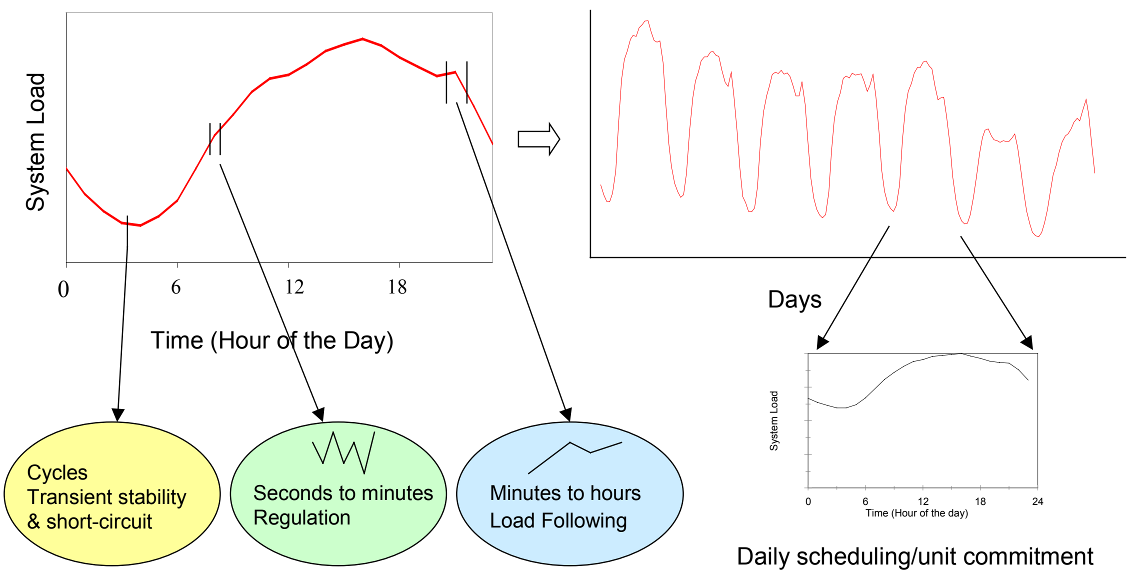

FIGURE 1. TIME SCALES OF UTILITY OPERATIONS.

Once units have been committed, they can be used to provide capacity and energy to the grid. Loads will vary during the day, so some of the units that are online will ramp up or down to match the load. This is the load following time scale, and it ranges from 10 minutes to several hours. There are also very short-term fluctuations in load that must be matched by the generators. These variations occur over short intervals, typically less than 2 minutes. Some generators are typically controlled directly by automatic generation control (AGC) computers that regulate the power output as necessary.

PacifiCorp's approach was to divide costs associated with wind integration into two relatively broad categories: Incremental Reserve Requirements and Imbalance Costs. The Incremental Reserve Requirements category encompassed the increased need for operating, load following, and regulating reserves to maintain system reliability within required limits. The Imbalance Costs category captured the difference in system operating costs experienced by a system that meets load with an incremental amount of wind resources versus the same system meeting an identical load with an incremental amount of energy equivalent to the wind project, but delivered at constant rate. Such costs may include costs to additional unit start-ups, the higher rate of incurring bid-ask spread penalties, or units that are forced to operate at less favorable points on their power curves.

Wind generation was treated as negative load for the purpose of calculating Incremental Reserve Requirements. The increase in reserves was assumed to be proportional to the fractional increase in the standard deviation of hourly loads over a year, with and without the wind generation. Because the current level of reserves held on the company's system was determined empirically from operating experience, the fractional increase was applied to the currently used quantity of load following reserves. Figure 2 shows the results of PacifiCorp's Incremental Reserve Analysis. It was tacitly assumed that regulating reserve requirements were not substantially affected. This was partly due to the fact that customers are not routinely charged for their specific contribution to the need for regulating reserve and the realization that treating wind as a negative load would likely not make it the foremost contributor to the need to hold regulating reserve.

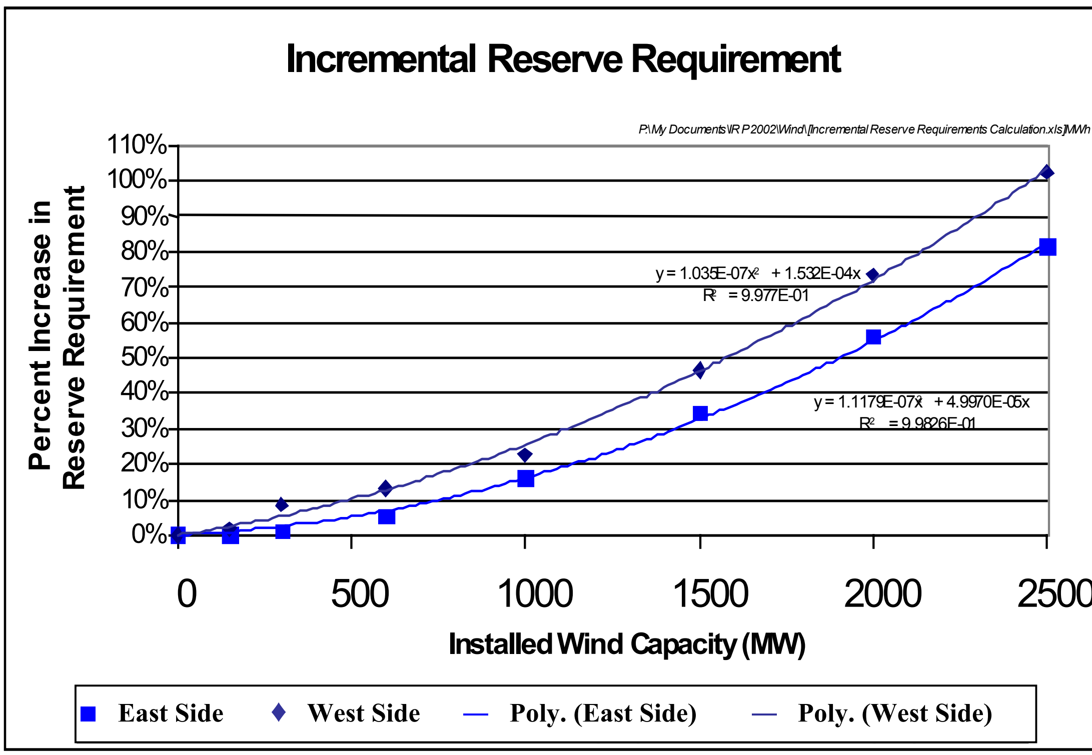

FIGURE 2. INCREMENTAL RESERVE REQUIREMENT.

System Imbalance costs were assessed by simply running Henwood's PROSYM hourly dispatch model with various levels of wind capability and comparing dispatch costs with runs, including similar quantities of flat energy (on an annual basis). The differences in system dispatch costs were attributed to the variable output nature of the wind projects and allocated on a per-megawatt-hour basis to the wind generation. Figure 3 shows the results of PacifiCorp's imbalance cost calculations.

WEAKNESSES IN PACIFICORP'S APPROACH

The PacifiCorp approach to estimating wind integration costs stressed relatively simple methods using available tools and techniques to rapidly arrive at reasonable cost estimates. A fuller analysis of reserve requirements would have specifically examined the need for different kinds of reserves at the different relevant time scales. Other approaches have specifically modeled resource response on time scales from less than a second to many hours to assess the change in resource requirements for wind resources. Such modeling efforts may entail ad hoc models specific to a particular power system. Assessing imbalance costs using hourly dispatch models is probably the best available approach at this time. However, the specific modeling techniques employed could be improved upon both by changes in the model algorithm and modifications in characterizing wind resources to the model.

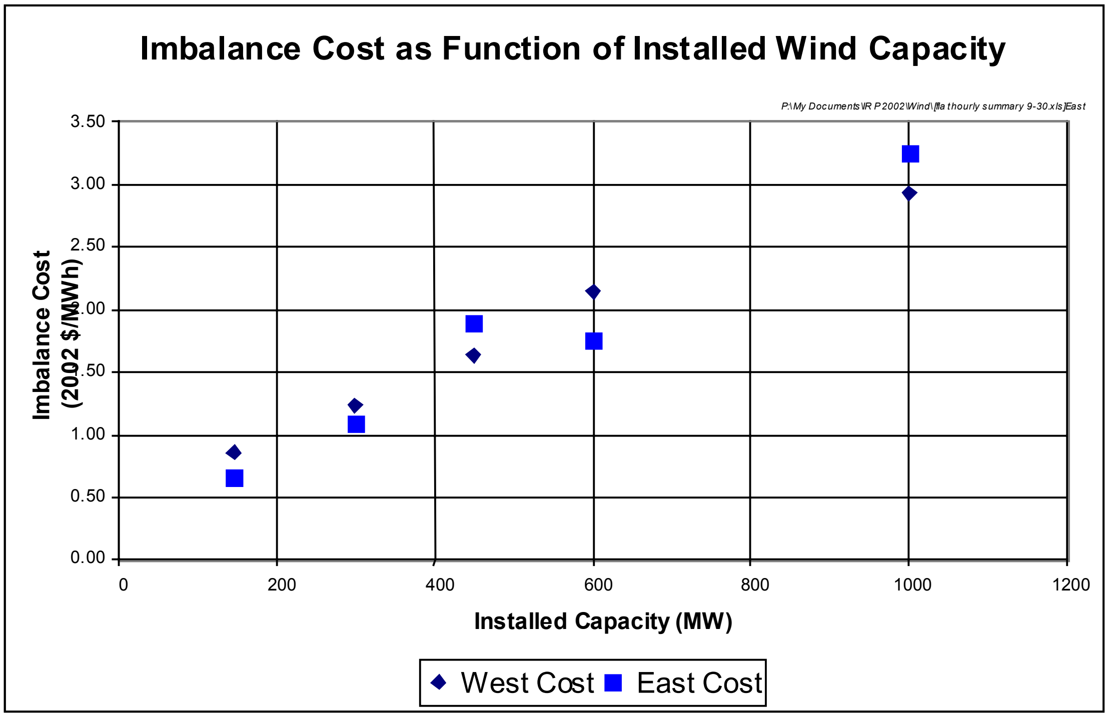

FIGURE 3. ESTIMATED IMBALANCE COST.

Incremental Reserve Requirements

Utilities hold reserves in order to meet unexpected changes in the basic load and resource balance in the system. Power system loads are typically estimated the day and hour before their actualization to ensure that an equal amount of generation is available on a real-time basis. Power system operators realize that forecasts of loads and resource availability prepared the day before, or even the hour before, real-time operations involve a significant amount of uncertainty. The term "reserves" refers to additional resources that can adjust their output relatively rapidly to accommodate unexpected changes in loads and resources.

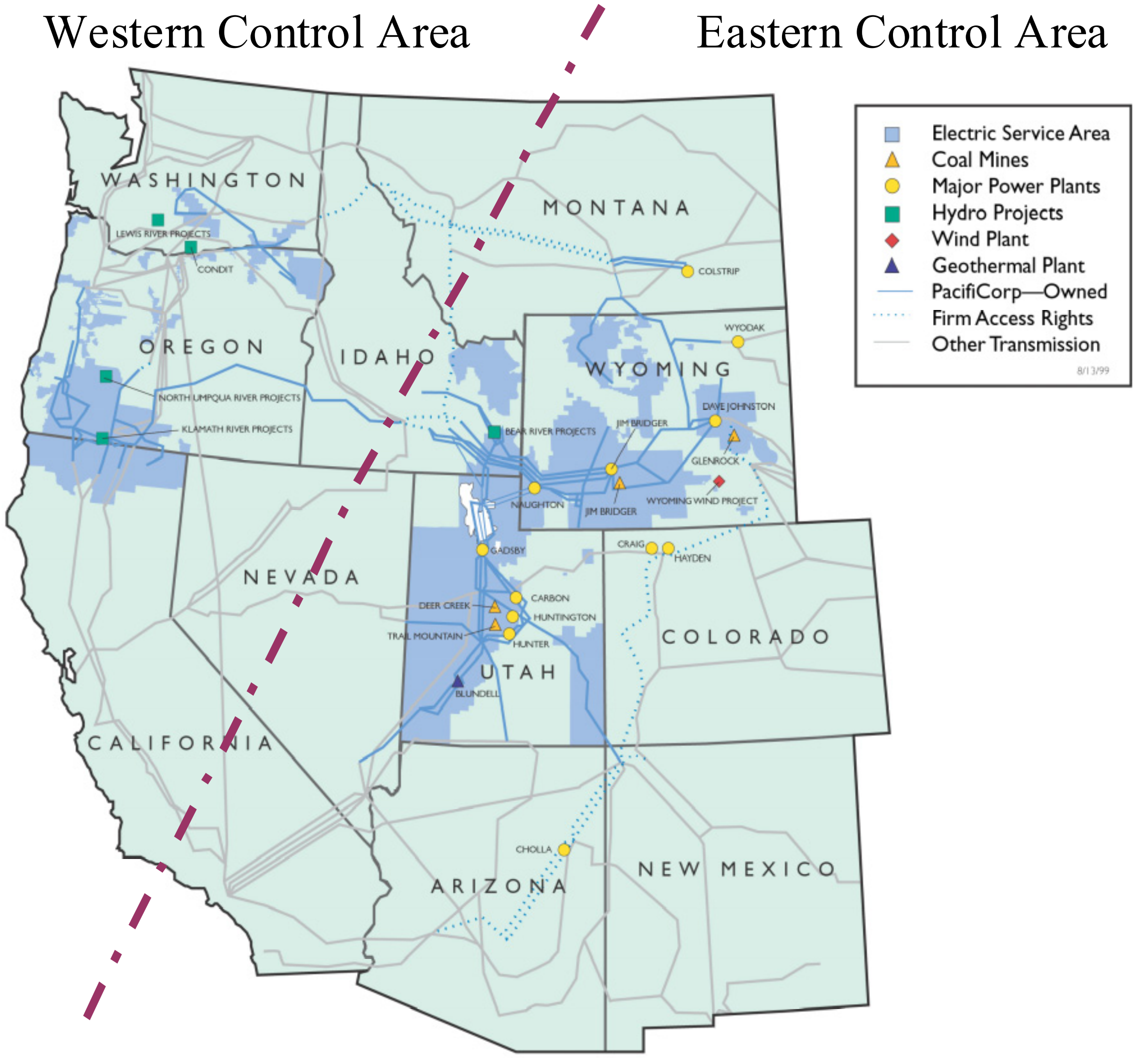

FIGURE 4. PACIFICORP POWER SYSTEM MAP AND CONTROL AREA.

Power systems are divided into geographic regions called “control areas.” PacifiCorp’s system is divided into two control areas (shown in Figure 4). Control area operators are responsible for meeting reliability criteria established by the various regional reliability councils. The primary measure that control area operators examine is the frequency of the power system. North American power systems keep the power system frequency near 60 Hz. If resources are less than demand in a control area, the frequency begins to drop. Conversely, systems with excess generation will experience a rise in the system frequency. Reliability standards set limits on the accumulated frequency errors on different time scales.

Complicating the task of identifying the incremental need for reserves on a power system is the fact that PacifiCorp operators assess the need for holding various types of reserves primarily through many years of operating experience, not through standardized computations. Minimum reserve requirements have been established to meet operating contingencies (sudden power plant outages or the loss of a major transmission facility). However, load following reserves (the ability to meet the dynamic change in demand of periods of minutes and hours) and regulating reserves (the ability to meet dynamic changes on the order of milliseconds to minutes) are generally established through experience, not calculation.

PacifiCorp simplified the problem by assuming that changes in wind output are not equivalent to the sudden loss of a thermal unit or transmission facility and therefore do not result in the need for any extraordinary contingency reserves. PacifiCorp further simplified the problem by assuming that the behavior of wind generation (at least for projects containing more than just a few turbines) is not sufficiently different from other system loads and resources on the time scale of less than a minute—obviating the need to analyze incremental regulating reserves.

These simplifying assumptions represent potential weaknesses in the analysis, but perhaps not very significant ones. The sudden drop in output from wind projects due to a decline in wind takes place on a time scale that is significantly longer than that of a generating unit or transmission facility trip. We have insufficient evidence of the behavior of wind projects tripping off due to wind speeds greater than cut-off, but our expectation is that the time scale of those events will also be longer than that for which contingency reserve requirements were designed. Neglecting the need for incremental regulating reserves is a rougher approximation. Studies have suggested that the additional costs are relatively small for regulating reserves, but certainly measurable.

PacifiCorp's assumption that load following reserves represent the bulk of the incremental reserve costs is probably a strong one. The primary weakness in PacifiCorp's approach lies in the methodology for determining incremental load following reserves. The PacifiCorp methodology established a single measure representative of the need for load following reserves based on hourly load data. The approach misses important intra-hour detail. In addition, it is incapable of differentiating between time of day and time of year. A more rigorous approach would assess the need for load following reserves on a finer time scale, probably with a simulated dispatch model.

Imbalance Costs

Imbalance Costs were assessed by adding wind generation to the PROSYM hourly dispatch model and comparing the computed costs with a second study absent the wind generation, but with an equal amount of generation provided in constant amounts over every hour. The differences in costs[1] were spread over the wind generation to arrive at the imbalance costs on a per-megawatt-hour basis. Widely available dispatch programs typically do not take into account some of the intricacies in the interaction between wind resources and modern power systems, as is discussed below. Nevertheless, dispatch models do a reasonable job of approximating it, given the limitations in the modeling framework and time constraints.

The costs of integrating wind resources depend strongly on the size and type of system into which they are being integrated. Figure 5 shows the makeup of PacifiCorp's system. One important consideration on PacifiCorp's system is the availability and dispatch of hydro resources. Hydro resources are relatively flexible and tend to be used to respond to the more rapid changes on the power system. The actual operation of extensive hydro systems is beyond the scope of most off-the-shelf dispatch models. PROSYM dispatches hydro against the load shape, minimizing the net exposure to high-priced generation to meet the daily peak load while meeting other hydro system requirements (e.g., minimum outflow levels). In practice, the hydro system would be used extensively to meet fluctuations in wind output. In the PacifiCorp analysis, however, wind generation was added as must-run generation that therefore excluded the hydro system from reacting to variations in wind output. PacifiCorp is working with Henwood to develop modeling protocols for wind generation that would allow the hydro system to react to wind generation—

[1] Costs include the operating costs of all resources in the power system, plus off-system sales, net of off-system purchases.

possibly by treating it as a negative load. The effect of not allowing hydro units to respond to wind tends to overestimate the imbalance costs.

Another issue with the modeling approach relates to unit commitment and wind forecast accuracy. Wind generation was included in the model as must-run generation. Unit commitment logic in PROSYM looks ahead to determine which of the thermal units need to be committed to generating. Some thermal units may take many days to generate full power after they are shut down. Conceptually, the model might look ahead and see that a significant amount of wind will be generated over the succeeding week and take a thermal unit off-line to save money. However, in actual operations, there may be little confidence that the wind will continue blowing over a period of many days, and operators would be unlikely to take a large thermal unit off-line. The perfect foreknowledge implicit in the analysis is a weakness in the study, tending to undercount imbalance costs. Again, PacifiCorp is working with Henwood on wind modeling protocols to address this issue.

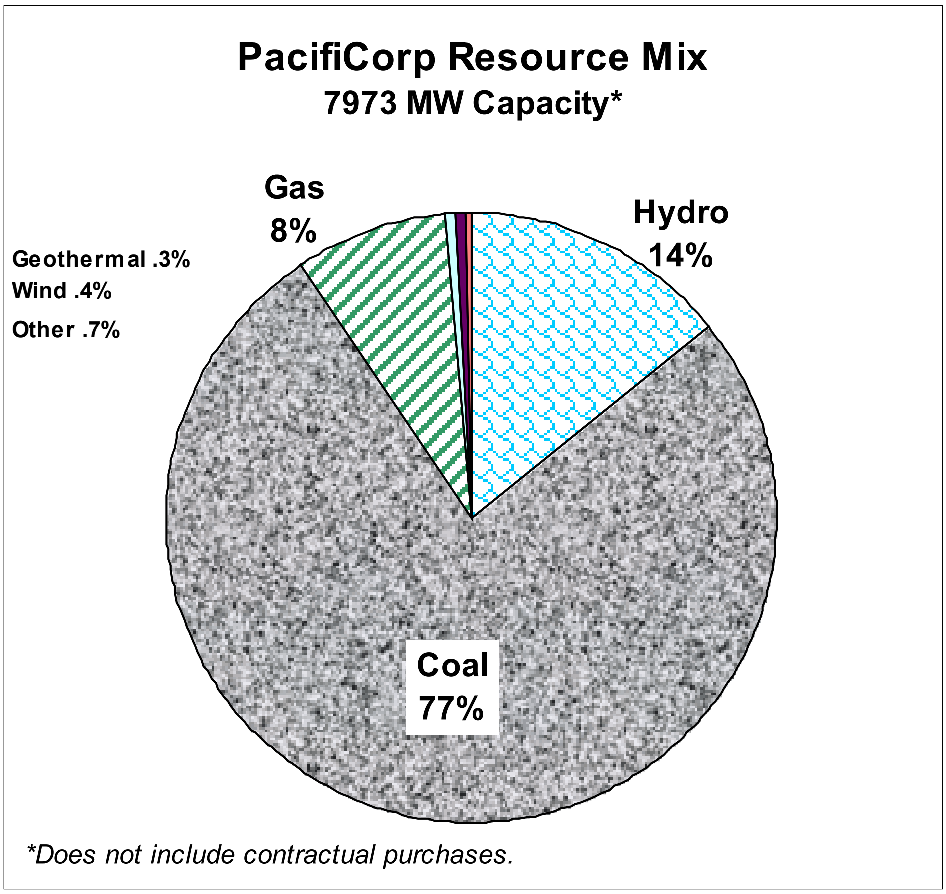

FIGURE 5. PACIFICORP RESOURCES.

The final issue identified as a weakness in the PacifiCorp approach relates to how market interactions were modeled. PROSYM was set up to meet load with resources on the system or to purchase from a market if prices were better or system resources were insufficient to meet load. It was expected that the variable output of wind projects would force the model to rely on market purchases and sales to a greater extent than would be necessary absent the wind resource. Market prices are estimated and input to the model such that sales into the market or purchases from the market are made at that price. A bid/ask spread is imposed to reflect imperfections in the market. The bid/ask spread is essentially a cost of doing business at the market price. A weakness in the PacifiCorp approach is that the bid/ask spread is an input to the model, but it was not rigorously examined at the time the model was run. It was also not clear to what extent the bid/ask spread was invoked (i.e., how much additional reliance on markets occurred in the studies). This issue is complicated by the lack of interaction with the hydro system, which might have mitigated some of the additional reliance on markets for meeting load.

OPERATING EXPERIENCE

PacifiCorp is gaining operational experience with significant amounts of wind generation on its system. It is important to verify that the operational issues experienced by system operators is in general accord with the analytical and modeling approaches used. PacifiCorp has asked operations personnel to keep track of the effects of wind in both the eastern and western control areas on system operations and costs (to the extent they can be determined). This information will be used to ensure that analytical approaches have not missed important pragmatic interactions that more theoretical approaches may have missed. At this early date, no major issues have surfaced with regard to system operations.

IMPROVEMENTS TO DISPATCH MODELS

Existing dispatch models provide a good overall framework to analyze the impact of wind power on the overall system. The intermittency and uncertainties surrounding wind power generation do introduce new issues to the overall dispatch process, and these are not yet integrated into the models. The implication is that, for companies such as PacifiCorp that are involved in evaluation of large-scale wind systems, these models fall short. This section provides a discussion of some of these shortcomings and recommends specific steps that model developers can take to improve these models.

Unit Commitment Logic

One of the most important aspects of a dispatch model is the unit-commitment logic. This logic is the specific algorithm that is used to determine which generating plants must be started, or committed, for the next several hours or days. Units that are committed are run at some minimum level and can be called on to provide more capacity or energy if needed. If a generator is committed when it is not necessary, additional costs are incurred. Conversely, if not enough capacity is committed, it is possible that insufficient capacity is available when needed, compromising system reliability or leading to an outage. The process of unit commitment is complicated by the many physical constraints relating to generator start-up and shutdown processes. To start many large generating units, a minimum boiler temperature must be achieved, and it may take a significant amount of time before electricity can be generated. Likewise, the shutdown process is often lengthy, and minimum downtimes are common among thermal units. These inter-temporal constraints make real-time power delivery more complex because electric demand is instantaneous, but the decision to commit generators must occur well in advance.

Most dispatch models have highly refined algorithms to calculate the commitment of generating units. Commercial dispatch models do a good job of capturing the complexities and economic tradeoffs of the unit commitment process. However, many (most) of the unit commitment algorithms are proprietary and are therefore “black boxes.” This makes it impossible for the analyst to determine whether a change in unit commitment schedules is necessary to accommodate wind generation or whether the new schedule is an artifact of the algorithm.

The unit-commitment logic in existing dispatch models does not explicitly take the uncertainty of wind generation into account. The commitment process looks ahead and, based on expected loads and resource availability, makes sure that the appropriate units are online. At this point, it isn’t clear how unit-commitment decisions will be made in practice for systems with significant amounts of wind. Anecdotal evidence suggests that there may be times when significant amounts of wind can be expected with a reasonably high degree of certainty, and conversely, times when it is fairly clear that the wind will not blow for the next few days. Once substantial amounts of wind begin appearing on power system grids, unit-commitment logic must take into account wind forecasts and forecast accuracy.

Uncertainty and Variability of Wind Power

Another shortcoming of dispatch models is their inability to adequately represent both the uncertainty and the variability of wind output. Some models can represent the variability of wind by modeling a wind plant as an hourly transaction (power purchase) or modification to system load. However, both of these approaches typically assume no uncertainty of the wind generation in each hour of the year. Conversely, modeling wind as a thermal unit with multiple blocks and forced outage rates tends to smooth the statistically expected wind output, although it does account for uncertainty. This is because most models don’t allow for hourly changes to the resource capacity and outage rates applied to the same unit. Reference [2] discusses how this can be accomplished for wind.

One approach to estimating a range of possible outcomes is to use a form of Monte Carlo simulation. Although many dispatch models include a form of Monte Carlo simulation, those implementations are usually based on conventional generator units and are not suitable for wind power plants. The Monte Carlo simulator must take the specific wind chronology into account. A typical implementation would result in a two-stage modeling process. The first stage would extract the statistical properties of the wind plant and then calculate a large number of wind scenarios. The second stage would then input each wind scenario into the dispatch model, one at a time, executing the model and capturing the results of interest. After each scenario has been simulated, the results can be captured and summarized so that various statistical distributions of costs can be analyzed. This is illustrated by the use of a Markov model in [3] and with ARIMA models in [4]. Figure 6 [5] illustrates the summary results from a Markov model that was used to calculate statistical distributions of effective load-carrying capability and annual energy. This is based on a 100-MW hypothetical wind plant, with hourly output that was calculated using actual and simulated hourly wind speed. The graph shows some results from 100 Monte Carlo Markov simulations each for three categories of variation: high wind energy, mean wind energy, and low wind energy.

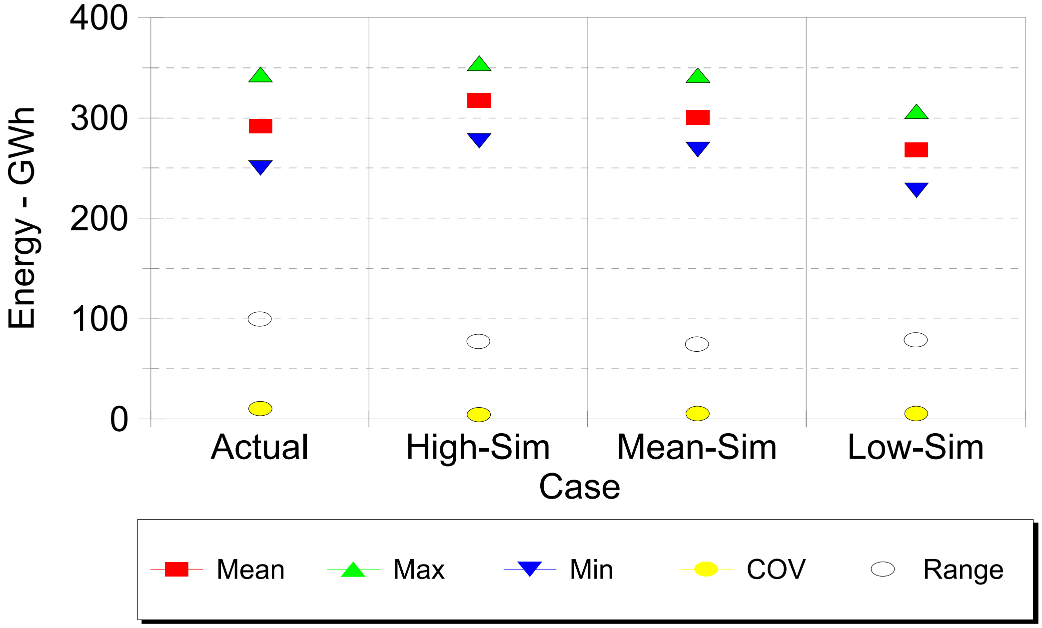

FIGURE 6. EXAMPLE MARKOV OUTPUT FOR 100-MW WIND PLANT.

Another aspect to wind generation uncertainty is the difference between predicted wind output and actual wind output. Because wind power can't be predicted with certainty, an additional component to uncertainty should be accounted for in the model. To completely capture the role of wind forecasts, the modeling environment should include the capability to use wind forecasts for different time scales. For example, a day-ahead forecast (with estimated forecast errors) would be used in the unit-commitment logic and forecasts for several hours in advance would be used to determine the optimal dispatch and load following impacts. Wind forecasting technology is changing, and it is beyond the scope of an economic dispatch model to incorporate explicit modeling methods. One approach might allow the user to simulate wind forecast errors based on past forecasting model performance, which would explicitly account for the specific forecasting technology in use for that utility. To accurately capture these impacts, the dispatch model would need the ability to differentiate between the longer-term day-ahead forecasts and the one-to-several-hour-ahead forecasts. This would also require appropriate modifications to both the unit commitment algorithm and dispatch algorithms to account for the relevant forecast errors.

Modeling and Endogenously Calculating Reserve Requirements Over Time

As utilities gradually move into new market structures, there is an increasing desire to analyze risk in a quantitative way. One important element of risk occurs in the daily operations of the system. Because the system operator must meet demand instantaneously, reserve capacity must be available to meet unforeseen increases in demand or sudden unexpected outages of generators or critical transmission lines. Often the reserve is based on a rule of thumb (such as 5%-7% of loads or generation) that have been shown to work reasonably well, but that are not based on any solid analysis.

The output of a chronological reliability model demonstrates the extreme variability in system risk that occurs over the year. This risk varies seasonally and diurnally and is also a function of various dynamic system conditions that can't always be included in the reliability analysis. Nevertheless, assuring a reliable supply of electricity is expensive and always requires some level of reserve capacity that is only called upon when needed. There is a tradeoff involved in selecting the desired level of reliability: too much reliability may not be worth the cost, whereas not enough reliability can cause real economic damage. Often a specific reliability target is chosen that compromises this tradeoff. One standard reliability level is a statistically expected 1 day in 10 years of outage caused by insufficient generation.

In some models, wind can be modeled as either a "firm" or "non-firm" energy source, at the discretion of the analyst. Firmness is, however, a question of degree because all plants have some probability of failure. To help analyze wind plants, it would be useful if the dispatch models allowed the analyst to choose among one or more risk-based approaches so that the *model* could determine the reserve level, based on probabilistic or risk-based criteria. A less desirable option would be to allow the analyst to perform an exogenous analysis of reserve requirements and import the hourly reserve requirement into the model. An extension of this capability would be to allow for Monte Carlo simulation of the system so that a statistical distribution of risks and system failures could be quantified.

OTHER AD HOC APPROACHES

Because of these modeling shortcomings, many analyses have been performed outside of a formal modeling framework. Some of this analysis is based on reasonably complete analytical foundations and could be incorporated into formal dispatch models; whereas others are more ad hoc in their approaches. Examples of studies done outside a dispatch model include [6] and [7].

We think that this type of analysis is useful in helping to capture some of the impacts of wind that can't be calculated by a conventional dispatch model. Also, these analyses help pave the way for more established techniques and algorithms that, we hope, will find their way into commercial dispatch models. However, it is important for these approaches to be established on a firm basis and that they examine wind integration in the context of the entire system. Ad hoc approaches can also sometimes be difficult to use for large utilities and may not be representative of well-established, well-tested techniques. Incremental approaches can also be useful, but a more robust approach for assigning integration costs to wind would not be dependent on the ordering of resources in the analysis. Such a method has been used in [8].

CONCLUSION

This paper has summarized the analytical approach that PacifiCorp used to evaluate significant levels of wind generation for its recent IRP. The evaluation focused primarily on load following reserves and imbalance costs. These are believed to be the primary cost impacts of wind on PacifiCorp's system. As the use of wind increases in PacifiCorp's system, it will become more important to perform more detailed analyses that also include the impacts of forecasting on different time scales and the unit-commitment issue. Existing dispatch models can be significantly improved in the way that they handle the variability of wind and various risks associated with higher levels of wind in the power system. We think it will become increasingly important to extend these modeling frameworks so that the impacts and costs of large-scale wind integration can be more fully analyzed in a rigorous analytical framework. Doing so will help determine the additional load following reserve impacts that wind might have on reliable power system operation.

Having said that, we also believe that PacifiCorp's approach and other ad hoc valuation methods can do a good job of determining the order of magnitude of wind integration costs. Because of its intermittency and the difficulty of predicting wind output, wind plants attract significant scrutiny. Although we welcome this scrutiny, it is important to recognize that power systems without wind also have significant variability, and the industry has become adept in accommodating these variations. As wind evaluation techniques continue to evolve, it will be important to analyze wind's variability in the context of the variability that already is an integral part of the power system.

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REPORT DOCUMENTATION PAGE

Form Approved
OMB NO. 0704-0188

1. AGENCY USE ONLY (Leave blank)	2. REPORT DATE	3. REPORT TYPE AND DATES COVERED
	May 2003	Conference paper

4. TITLE AND SUBTITLE
Assessing Wind Integration Costs with Dispatch Models: A Case Study of PacifiCorp: Preprint

5. FUNDING NUMBERS
WER3.3610

6. AUTHOR(S)
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7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

8. PERFORMING ORGANIZATION REPORT NUMBER
NREL/CP-500-34022

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)

10. SPONSORING/MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES

12a. DISTRIBUTION/AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

12b. DISTRIBUTION CODE

13. ABSTRACT *(Maximum 200 words)*
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14. SUBJECT TERMS
wind energy; PacifiCorp; hourly system dispatch model; wind resource integration costs; IRP; modeling; utility-scale wind

15. NUMBER OF PAGES

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT
Unclassified	Unclassified	Unclassified	UL