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Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date

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WIND POWER IMPACTS ON ELECTRIC POWER SYSTEM OPERATING COSTS: SUMMARY AND PERSPECTIVE ON WORK TO DATE

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Introduction

Wind power plants generate electricity when the wind is blowing, and the plant output depends on the wind speed. Wind speeds cannot be predicted with high accuracy over daily periods, and the wind often fluctuates from minute to minute and hour to hour. Consequently, electric utility system planners and operators are concerned that variations in wind plant output may increase the operating costs of the system. This concern arises because the system must maintain balance between the aggregate demand for electric power and the total power generated by all power plants feeding the system. This is a highly sophisticated task that utility operators and automatic controls perform routinely, based on well-known operating characteristics for conventional power plants, sophisticated decision-support algorithms and systems, and a great deal of experience accumulated over many years. In general, the costs associated with maintaining this balance are referred to as ancillary-services costs.

System operators are concerned that variations in wind plant output will force the conventional power plants to provide compensating variations to maintain system balance, thus causing the conventional power plants to deviate from operating points that are chosen to minimize the total cost of operating the entire system. The operators' concerns are compounded by the fact that conventional power plants are generally under their control and thus are dispatchable, whereas wind plants are controlled instead by nature. Although these are valid concerns, it is important to understand that the key issue is not whether a system with a significant amount of wind capacity can be operated reliably, but rather to what extent the system operating costs are increased by the variability of the wind.

Major Questions

Variability of wind-plant output has raised a number of key questions among electric power system personnel:

- Do wind plants require backup with dispatchable generation, and if so, to what extent?
- How are the costs of operating the power system affected by the inclusion of wind power in the generation mix?
- How can these cost impacts be evaluated? Should they be based on actual cost-of-service impacts or on market prices for ancillary services?
- How do these cost impacts vary with wind power's penetration of the system generation mix and with variations in other key system characteristics like generation mix, fuel types and costs, and access to external markets for energy purchases and sales?
- How should penetration be defined in light of evolving changes in power system operation as a result of ongoing restructuring in the electric power sector?
- How would improvements in wind forecasting affect cost impacts?

Over the past two years, several investigations of these questions have been conducted by or on behalf of U.S. electric utilities. These studies addressed utility systems with different generating resource mixes and employed different analytical approaches. In aggregate, this work provides illuminating insights into the issue of wind's impacts on overall electric system operating costs.

Summary of Studies Conducted to Date

A summary of the results from the recent studies is provided below. The studies use different methodologies and approaches, but their common element is that they seek to determine the cost of ancillary services necessary to accommodate a wind plant on a utility system. There are typically three time scales of interest, which correspond to the operation of the utility system and the structure of the competitive electricity markets:

- **unit-commitment** horizon of 1 day to 1 week with 1-hour time increments

- **load-following** horizons of 1 hour with 5- to 10-minute increments (intra-hour) and several hours (inter-hour)

- **regulation** horizon of 1 minute to 1 hour with 1- to 5-second increments.

Each of these time frames has special planning and operating requirements and costs. In the unit-commitment time frame, decisions must be made about which units to start and stop and when to do so to maintain system reliability at minimum cost. The challenge with wind is to do this without knowing precisely the amount and timing of energy production by the wind plant over the day(s)-ahead planning horizon. In the load-following time frame, the challenge is to have adequate reserve capacity available to ramp units up and down to follow the load shape resulting from the random fluctuations in the combined load and wind plant output. In the regulation or load-frequency-control time frame, sufficient regulating capacity must be available from the units on regulating duty to hold deviations within the tolerance prescribed by the North American Electric Reliability Council. The statistically acceptable deviations are quantified in the Control Performance Standards 1 and 2 (CPS-1 and CPS-2)

UWIG/Xcel Energy [(1)]

The case study conducted to evaluate the operational impacts of wind generation on the XCEL-NORTH system used traditional utility simulation-based scheduling and operation tools to conduct the analysis. The study, available on the Utility Wind Interest Group (UWIG) Web site (http://www.uwig.org), determined the ancillary-service costs incurred by XCEL-NORTH to accommodate its existing 280-MW wind plant in Minnesota. The XCEL-NORTH system is summer peaking, with a peak load slightly in excess of 8,000 MW. The total system generation is approximately 7,200 MW, with the difference made up by power purchases. A discussion of the ancillary-service cost increment for each of the time frames follows.

- *Unit commitment:* Simulations were performed to assess the cost incurred by XCEL-NORTH to reschedule units because of inaccuracy associated with the wind generation forecasts used in the day-ahead scheduling. Results based on the assumptions used and the assumed range of wind-production forecast error are shown in Table 1. As demonstrated in the results, the cost impact increases as the inaccuracy of the forecast increases.

TABLE 1: COST OF WIND FORECAST INACCURACY AS A FUNCTION OF FORECAST ERROR

Distribution Range (%)	±10	±20	±30	±40	±50
Extra Cost ($/MWh)	0.391	0.716	0.995	1.231	1.436

- *Load-following reserves:* Calculation of the intra-hour load-following reserve requirement (LFRR) of the XCEL-NORTH control area load and aggregate wind generation data indicated that the addition of 280 MW of wind capacity did not significantly increase the LFRR. Consequently, the reserve component of the load-following cost was assumed to be zero at this penetration level. However, this resulted in a higher intra-hour load-following energy cost from existing conventional generating capacity.

- *Intra-hour load-following energy*: Economic dispatch simulations were performed to evaluate the cost of following the intra-hour ramping and fluctuation of wind generation. This is the cost of deploying the available load-following reserve to meet the relatively slow intra-hour variation of net customer loads. Simplifying assumptions and extrapolations were made to obtain an annualized intra-hour load-following energy cost of approximately 41¢/MWh.

- *Regulation reserves:* Load frequency control (LFC) simulations produced results showing almost no change in the ACE standard deviation between the scenarios, including and excluding wind generation. This suggests that XCEL-NORTH's current wind penetration of 280 MW on an 8,000 MW peak system has no significant impact on the control performance. Accordingly, the cost impact of additional regulating reserves to accommodate wind is assumed to be negligible.

Summing the cost impact results for the components assessed over the three time frames and using the forecast error range of +/- 50%, the impact of integrating XCEL-NORTH's existing 280-MW wind plant is approximately $1.85/MWh of wind generation. The assumptions and extrapolations necessary to conduct the study were made to produce a more conservative (more significant) impact. The results are, however, specific to the system as it currently exists.

PacifiCorp [2]

PacifiCorp, a large utility in the northwestern United States, operates a system with a peak load of 8,300 MW that is expected to grow to 10,000 MW over the next decade. PacifiCorp recently completed an Integrated Resource Plan (IRP) that identified 1,400 MW (14%) of wind capacity over the next 10 years as part of the least-cost resource portfolio. A number of studies were performed to estimate the cost of wind integration on its system. The costs were categorized as incremental reserve or imbalance costs. Incremental reserves included the cost associated with installation of additional operating reserves to maintain system reliability at higher levels of wind penetration, recognizing the incremental variability in system load imposed by the variability of wind plant output.

Imbalance costs captured the incremental operating costs associated with different amounts of wind energy compared to the case without any wind energy.

At wind penetration levels of 2,000 MW (20%) on the PacifiCorp system, the average integration costs were $5.50/MWh, consisting of an incremental reserve component of $2.50 and an imbalance cost of $3.00. The cost of additional regulating reserve was not considered. These costs are considered by PacifiCorp to be a reasonable approximation to the costs of integrating the wind capacity.

Bonneville Power Administration (BPA) [(3)]

BPA is a federal agency that operates a large federal hydropower and transmission system in the northwestern United States with a peak load of 14,000 MW. Faced with interconnection requests for several thousand megawatts of wind capacity, BPA engaged Eric Hirst to conduct a preliminary study of the operating impact of wind on its system. Hirst investigated the cost of ancillary services in three time frames: day-ahead unit commitment, intra-hour balancing, and regulation. Based on wind data supplied by BPA and conservative assumptions that were unfavorable to wind, Hirst calculated the cost of ancillary services for the addition of 1,000 MW of wind energy. The costs of the ancillary services ranged from $1.00-1.80/MWh in the unit commitment time frame, $0.28/MWh for intra-hour load following, and $0.19/MWh for regulation, for a total additional cost of $1.47-2.27/MWh.

Hirst [(4)]

Using wind plant output data from the Lake Benton II project in Minnesota, Hirst calculated the cost of intra-hour load-following service and regulation service for a wind plant in the electricity markets of the Pennsylvania-Jersey-Maryland (PJM) regional transmission organization (PJM covers Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia) for one week each in August 2000 and January 2001. The wind plant modeled was 103 MW, and the summer peak load for the PJM system was 52,000 MW. During August, a period of high market prices in PJM, the load-following and regulation services for the wind plant amounted to $2.80/MWh and $0.30/MWh, respectively. The same services in January amounted to $0.70/MWh and $0.05/MWh, respectively. Although these results are necessarily of limited applicability due to the assumptions made, they are of interest because they recognize the importance of overall system balance as opposed to balancing individual wind plants, and they provide plausible order-of-magnitude costs. These estimates are likely conservative in that they do not represent the operation of a robust, fully functional ancillary-services market.

We Energies [(5)]

Operating in Wisconsin and the Upper Peninsula of Michigan, We Energies serves a summer peak load of 6,000 MW with installed capacity of 5,900 MW of primarily coal and nuclear units. We Energies relies on additional capacity from purchases to meet peak demands during all seasons. We Energies set a goal to produce 5% of its energy from renewable resources by 2005. Electrotek was retained to assist in evaluating the impact on ancillary service costs of adding up to 2,000 MW of wind capacity by 2012. Working with We Energies staff, Electrotek examined ancillary service costs in the regulation, load following, and unit-commitment time frames. For wind penetration levels varying from 250 MW to 2,000 MW for a 7,000-MW peak load in 2012, Electrotek found ancillary service costs ranging from $2/MWh to $3/MWh, with load and wind variations considered together. Sensitivity studies showed that the increase in regulation reserve for wind integration was small compared to the reserve carried for normal system regulation purposes associated with load variations and load forecast uncertainty.

Great River Energy (GRE)[6]

GRE is a Generation and Transmission electric cooperative serving parts of Minnesota and northeast Wisconsin. It is primarily a thermal system in the Mid-Continent Area Power Pool (MAPP) region with a summer peak load in excess of 2300 MW, growing at 3%-4% per year. GRE is experiencing increased customer demand for wind energy and is responding to a state renewable energy objective in Minnesota to attain 1% of the state's energy needs from renewable energy in 2005, growing by 1% per year to 10% by 2015. As part of its planning process to meet this objective, GRE performed a study with Electrotek that examined adding 500 MW of wind in 100 MW increments between now and 2015. GRE operates with a fixed fleet of generation and uses a static scheduling process, so it did not decompose the problem into the three time periods commonly used in the analysis of ancillary-service costs in larger utilities. It also looked at providing the ancillary services required from its own resources, including a 600-MW combined-cycle unit, which was subsequently cancelled. GRE found ancillary-service costs of $3.19/MWh at 4.3% penetration and $4.53/MWh at 16.6% penetration. It is likely that the costs would have been higher without the combined-cycle unit and self-providing the ancillary services without economical intermediate resources.

NREL Paper [7]

Parsons et al. summarized the results of recent operating impact studies in the United States, including those above, in a recent National Renewable Energy Laboratory (NREL) paper for the 2003 European Wind Energy Conference (EWEC). It presents a summary of both the methodologies and the results. This paper, titled "Grid Impacts of Wind Power: A Summary of Recent Studies in the United States," is available on the NREL (http://www.nrel.gov) and UWIG (http://www.uwig.org) web sites.

California Study[8]

California's recently enacted Renewable Portfolio Standard requires the state's investor-owned utilities to provide 20% of all electric energy from renewable sources by 2017. To help assess the non-market integration costs of renewables, the California Energy Commission (CEC), in cooperation with the California Public Utilities Commission (CPUC), organized a team to study these integration costs. The first phase of the study examined the integration costs of the existing renewable energy fleet. Phase One results are available at http://cwec.ucdavis.edu/rpsintegration/. The incremental regulation cost associated with existing wind generation was found to be $0.17/MWh. Subsequent phases of the study will examine the impact of additional renewable energy in the California system. One of the unique characteristics of the study was the extensive use of detailed data from the CA Independent System Operator (ISO) Plant Information (PI) database, providing a retroactive look at the actual impact of renewables in CA.

Summary of What We Know

Based on the results to date, several insights can be gained and generalizations can be made. First and most important, it can be seen that the incremental cost of ancillary services attributable to wind power is low at low wind penetration levels; as the wind penetration level increases, so does the cost of ancillary services. Second, the cost of ancillary services is driven by the uncertainty and variability in the wind plant output, with the greatest uncertainty in the unit-commitment time frame, or day-ahead market. Improving the accuracy of the wind forecast will result in lower cost of ancillary services. Third, at high penetration levels the cost of required reserves is significantly less when the combined variations in load and wind plant output are considered, as opposed to considering the variations in wind plant output alone.

The results to date also lay to rest one of the major concerns often expressed about wind power: that a wind plant would need to be backed up with an equal amount of dispatchable generation. It is now clear that, even at moderate wind penetrations, the need for additional generation to compensate for wind variations is substantially less than one-for-one and is generally small relative to the size of the wind plant.

A summary of the results of the current studies is provided in the table below. Although the tools and methods are imperfect, there is sufficient information to show that the operating impacts are small at low penetration levels and moderate at higher penetration levels.

TABLE 2: SUMMARY OF RESULTS

		$/MWh			
Study	Relative Wind Penetration (%)	Regulation	Load Following	Unit Commitment	Total
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00 - 1.80	1.47 - 2.27
Hirst	0.06 - 0.12	0.05 - 0.30	0.70 - 2.80	na	na
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3				3.19
Great River II	16.6				4.53
CA RPS Phase I	4	0.17	na	na	na

Summary of What We Don't Yet Understand

The studies to date have examined complex systems with many interacting variables. The sensitivity of the results of the current studies to critical modeling assumptions and parameter values should be investigated in order to gain a better understanding of the critical parameters. Important factors to investigate and further explore include:

- ***Varying amounts of wind generation.*** It is clear that the cost of ancillary services increases with increasing wind penetration. A better understanding of this increase for different types of systems and associated mitigation methods should be developed. Nonlinear effects – especially at high penetration levels – should be investigated with system simulation tools.

- ***Market structure and imbalance energy pricing.*** Market-based ancillary-service costs will differ from those provided by a utility in a vertically integrated environment. The availability of a robust hour-ahead market or a well-functioning regional balancing energy market would likely lead to lower cost impacts.

- ***Correlation of load and wind forecasting error.*** A better understanding of the magnitude and correlation of the respective forecast errors is necessary to generate more accurate results and enable more simplifying assumptions to be made in future analyses.

- ***Varying generation portfolio and fuel cost mix.*** Sensitivity studies need to be conducted on a selected set of representative generation mix scenarios (coal, oil, gas, hydro, nuclear, wind) to enable results to be extrapolated to other utility systems without the need to undertake expensive and time-consuming utility-specific studies.

- ***Simplified models and methods.*** Once a sufficient base of results has been established, correlations among analytical and simulation approaches, trends in results, similarities, and insights should be sought in order to develop simplified approaches and "rules of thumb."

- ***Wind penetration definition.*** A new and more meaningful definition of wind penetration level needs to be developed. The definition needs to change to reflect the changes in the growth and geographical extent of competitive electricity markets and consolidation of control areas. Ancillary services will be drawn from larger market areas with more competition as markets mature.

- ***Transmission congestion.*** We do not have a clear understanding of the impact of transmission congestion on ancillary-services markets as these markets begin to mature. At some point, this is likely to become a limiting factor on the provision of ancillary services for regions with large amounts of wind capacity.

This additional analysis will provide a better understanding of the impacts of integrating bulk wind generation into a utility resource mix, as well as insights needed to extrapolate the results to other utility systems.

Summary and Future Expectations

Work conducted to date shows that wind power's impacts on system operating costs are small at low wind penetrations (about 5% or less). In most cases, these incremental costs would detract from the value of wind energy on current wholesale markets by 10% or less. At higher wind penetrations, the impact will be higher, although current results suggest the impact remains moderate with penetrations approaching 20%.

The additional areas of further study identified above will provide additional important insights that will allow credible estimation of impacts of wind generation at higher penetrations, as well as for a wide range of utility systems. These insights likely will also lead to operating procedures that will mitigate operating-cost increases due to wind. In the longer term, they may also influence the future expansion of power systems so that the naturally variable behavior of wind power has less impact on overall operating costs than is the case with today's power systems.

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System operators are concerned that variations in wind plant output will force the conventional power plants to provide compensating variations to maintain system balance, thus causing the conventional power plants to deviate from operating points chosen to minimize the total cost of operating the system. The operators' concerns are compounded by the fact that conventional power plants are generally under their control and thus are dispatchable, whereas wind plants are controlled instead by nature. Although these are valid concerns, the key issue is not whether a system with a significant amount of wind capacity can be operated reliably, but rather to what extent the system operating costs are increased by the variability of the wind.

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