William M. Eddie (ISB# 5800)
ADVOCATES FOR THE WEST
P.O. Box 1612
Boise, ID 83701
(208) 342-7024
fax: (208) 342-8286
billeddie@rmci.net

Express Mail:
1320 W. Franklin St.
Boise, ID 83702

RECEIVED [X]
FILED [ ]
2005 JUL 15 PM 4:51
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF OF IDAHO POWER COMPANY FOR AN ORDER TEMPORARILY SUSPENDING ENTER INTO CONTRACTS TO PURCHASE ENERGY GENERATED BY WIND-POWERED SMALL POWER PRODUCTION FACILITIES	)))))))	CASE NO. IPC-E-05-22

DIRECT TESTIMONY OF TROY GAGLIANO

ON BEHALF OF RENEWABLE NORTHWEST PROJECT

AND NW ENERGY COALITION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE RENEWABLE NORTHWEST PROJECT.

A. My name is Troy Gagliano and I am a Senior Policy Associate with Renewable Northwest Project in Portland, Oregon. My business address is Renewable Northwest Project ("RNP"), 917 SW Oak St, Suite 303; Portland, Oregon, 97205. Established in 1994, RNP promotes the responsible expansion of solar, wind and geothermal energy in the Northwest. We work to establish policies that support renewable energy development and nurture the development of a market for renewables. Our unique coalition of members includes renewable energy project developers, public and consumer interest groups, turbine manufacturers, environmental organizations and others.

Q. PLEASE DESCRIBE YOUR EDUCATION, BUSINESS EXPERIENCE AND RESPONSIBILITIES.

A. I hold a Master's Degree in International Public Policy from the University of Denver's Graduate School of International Studies. At RNP I focus mainly on project siting and permitting issues and the regulatory aspects of renewable energy. I represent RNP on the Energy Trust of Oregon's Renewable Advisory Committee and the Western Governor's Association's Clean and Diversified Energy initiative. From 2000-2004 I was a renewable energy policy consultant at the National Conference of State Legislatures (NCSL) in Denver, Colorado. I represented NCSL on the steering committees of the National Wind Coordinating Committee and the National Geothermal Collaborative.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Renewable Northwest Project and the NW Energy Coalition.

Q. PLEASE SUMMARIZE THE POSITION OF RNP AND NW ENERGY COALITION ON THE ISSUE NOW BEFORE THE COMMISSION.

A. We support a very limited suspension of PURPA to allow the Commission to address the specific issue of preventing developers from dividing large commercial projects into 10 MW increments in order to qualify for the avoided cost rate. We believe this can be accomplished with the establishment of new PURPA implementation policies addressing this issue within this docket over the next three (3) months.

In the mean time, wind developers should be allowed to seek an expedited case-by-case approval (if they cannot reach agreement with Idaho Power) within this docket that their project should qualify for the published avoided cost rates. This case-by-case approval should evaluate criteria including: (a) whether the project can demonstrate it is not one component of a potentially larger commercial project, and (b) whether the project has made substantial investments in reliance upon the availability of the avoided cost rates and the federal production tax credit, which is set to expire at the end of 2005, (c) the status of the project's negotiations with Idaho Power, and (d) other criteria as the Commission determines to be appropriate. We believe this would strike a balance between ensuring Idaho Power ratepayers enjoy the benefits of both smaller distributed generation, as well as the cost benefits of larger commercial wind projects acquired through competitive processes; and further ensure that developers' reasonable investment-backed expectations are not thwarted.

We do not support the suspension for the reasons that Idaho Power states and we are concerned that a longer suspension may hinder the company from following through with its 2005 RFP.

We support the acquisition of larger wind projects through competitive bidding processes. We believe Idaho Power's decision in the 2004 IRP to acquire additional renewable resources was prudent and represents real benefits for customers. We strongly urge the Company to remain committed to acquiring the 350 MW of wind and 100 MW of geothermal energy that the IRP called for.

We also support the development of locally owned renewable energy projects under PURPA and the community scale model of wind development that this policy supports. We believe that large commercial projects should compete through a utility RFP based on price and that PURPA rules should prevent commercial projects from being broken into smaller ones to qualify for PURPA.

Q. WHAT IS YOUR POSITION ON IDAHO POWER'S REQUESTED SUSPENSION OF PURPA AS IT APPLIES TO WIND PROJECTS?

A. We strongly disagree that PURPA's availability should be suspended on the basis that Idaho Power must first conduct a wind integration study. As discussed below, integration costs have been evaluated by numerous other utilities and entities, and have uniformly been found to be quite small at the level of wind penetration Idaho Power is considering. The proper time to conduct such a study would be after the Company integrates a more substantial amount of wind power on their system, allowing the Company to evaluate real impacts rather than computer models. Should the Company then think a study is necessary, we believe an independent third party should conduct it through the Integrated Resource Planning process. Until that time, we believe the Company can use an estimate within the range of the study results from the Utility Wind Interest Group study cited below.

For these reasons we believe that the Commission should encourage Idaho Power to quickly move forward on its 200 MW wind RFP. Based on discussions with developers, we believe there are some good proposals in front of the Company and that the average cost of those proposals as stated by Idaho Power is still least cost and least risk for customers.

Q. IDAHO POWER STATES IN ITS PETITION THAT THE CURRENT PURPA RULES ENCOURAGE DEVELOPERS TO TAKE ADVANTAGE OF PURPA BY BREAKING UP LARGER PROJECTS INTO SMALLER ONES TO QUALIFY FOR THE AVOIDED COST RATE. HOW SHOULD THIS ISSUE BE ADDRESSED?

A. This certainly is a legitimate concern, but at this point we have no information to confirm that a large project has actually been divided into smaller projects to take advantage of the PURPA implementation in Idaho.

We encourage the Commission to expeditiously investigate this issue to ensure the proper safeguards are in place to prevent any possible "gaming" of the system. There are a number of policy design criteria regarding project ownership, layout, and interconnection that the Commission could consider as an issue in this case. Minnesota has recently addressed this and provides one example of criteria that may help Idaho Power address the issue. A Minnesota law states that no one investor can own more than a certain percentage of the project. The purpose here is to prevent gaming and encourage local ownership of community wind projects. This issue should be addressed later within this docket.

Q. DO YOU BELIEVE THAT INTEGRATION OF WIND POWER AT THE LEVEL OF 350 MW INSTALLED CAPACITY (PER IDAHO POWER'S 2004 INTEGRATED RESOURCE PLAN) WILL BE UNDULY EXPENSIVE OR DIFFICULT?

A. The information on integration costs of wind power is well known and there are several studies that show it to be affordable. I am sponsoring Exhibit 1 and Exhibit 2. Exhibit 1 is a brief document titled "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date." This document is a summary of different wind integration studies for several utility systems that engineers at the National Renewable Energy Laboratory and the Utility Wind Interest Group published in March 2004. This summary includes total wind integration costs at penetration levels ranging from 4% to 20% for various utilities across the country including the Bonneville Power Administration, PacifiCorp and XCEL. It shows that total wind integration costs per MWh for these utilities ranges from $1.47/MWh for BPA at 7% penetration to $4.64/MWh for PacifiCorp at 20% penetration. Exhibit 2 is an updated version (from March 2005) of the summary table that appears as Table 2 on page 8 of Exhibit 1.

There are nearly a dozen additional integration studies available on the Utility Wind Interest Group (UWIG) website (http://www.uwig.org/operatingimpacts.html). UWIG provides a forum for the critical analysis of wind technology for utility applications and has nearly 60 utility members, including Idaho Power. We encourage

Idaho Power to work closely with its colleagues at UWIG on wind integration issues. Hydropower is a great match with wind and considering the large amount of hydropower on its system, the Company seems well suited to integrate wind power.

If all 350 MW of wind were installed on Idaho Power's system, as planned in the 2004 IRP, actual production from these facilities would probably average 115 to 125 MW. Idaho Power's average load ranges from about 1300 MW up to about 2200 MW. This level of penetration of wind power (averaging less than 10%) would fall comfortably within the levels that other utilities and entities have studied, as cited above. The very modest integration costs expected under these studies do not warrant suspension of PURPA at this time.

Q. IDAHO POWER STATES THAT $55.00/MWH WAS THE AVERAGE PRICE FROM ALL RESPONSES TO ITS REQUEST FOR PROPOSALS FOR WIND POWER. IS THAT PRICE OUTSIDE THE RANGE OF THE CURRENT PRICES?

A. No. While $55.00 is higher than what Idaho Power expected in its 2004 IRP, it is still within the range of wind prices in the Northwest. Based on our experience, the prices for existing large wind projects in the Northwest and in Wyoming over the last 7 years range from just over $30.00 per MWh to nearly $60.00 per MWh.

It is worth noting a recent example of the cost effectiveness of wind energy from Puget Sound Energy's (PSE) 2004 all source RFP. According to PSE, the levelized energy cost for their short-listed wind bids range from $44.00 per MWh to $50.00 per MWh for delivered energy as compared to $60.00 to $65 for the best natural gas bids (also for delivered energy). Coal power resources were in the range of the low $50s per MWh.

Q. WHY DO YOU THINK THE RFP BID PRICES IDAHO POWER RECEIVED ARE HIGHER THAN WHAT THE UTILITY EXPECTED?

A. The major driver for the recent increase in wind energy costs across the industry is that in early 2005 the price of wind turbines increased. There are a number of factors contributing to this including higher worldwide steel prices, a weak U.S. Dollar compared to the Euro, and increases in freight prices resulting from higher gasoline prices. Another factor is the rise in the cost of construction labor. Finally, the short-term extension of the federal production tax credit for wind power leads to greater demand and limited supply of wind turbines.

Idaho Power claims in its petition that the current avoided cost rates influenced the bids the Company received in its 2005 RFP. We see no evidence to confirm that this is happening. We feel that RFP processes gives developers the incentive to compete on price. It is difficult to believe that they would collude to raise their bid price closer to the avoided cost rate; or that all the developers desire (and are able) to break up their projects into 10 MW increments so as to qualify for the avoided cost rate.

Q. IN THE TESTIMONY OF JOHN GALE, IDAHO POWER REFERENCES THE JUDITH GAP WIND PROJECT IN MONTANA. DOES RNP HAVE ANY SPECIFIC INFORMATION ABOUT THAT PROJECT?

A. RNP has been very involved with advancing wind energy in Montana over the past 8 years. Since 2000, we have worked with Northwestern Energy (NWE) (and its predecessor Montana Power) and supported its efforts to secure a commercial scale wind project. NWE selected the Judith Gap project through an RFP issued in July 2004.

Although RNP sits on NWE's Technical Advisory Committee, we were not involved in the actual selection of the Judith Gap project.

RNP intervened (represented by a staff member other than myself) in the advanced approval proceeding for Judith Gap before the Montana Public Service Commission in February 2005. However, we did not sign the confidentiality agreement and therefore were not privy to any confidential information about the project.

NWE signed a 20-year contract in December 2004 for 135-150 MW of wind from Judith Gap for around $32/MWh. This is the busbar price of the project, and does not include transmission and integration costs. The price reflects the benefit of the federal Production Tax Credit as well as a state property tax reduction bill that passed the Montana legislature this year. It was estimated that without this property tax legislation the cost of the project would be about $2/MWh higher. Montana has very robust wind resources and the estimated capacity factor for Judith Gap is 37% or potentially greater. This capacity factor contributes to its competitive price.

Q. HOW DOES THE COST OF JUDITH GAP COMPARE TO OTHER PROJECTS IN THE REGION?

A. The busbar cost of Judith Gap makes this one of the most competitive wind projects in the region. It represents the lowest point in the range of wind energy prices in the Northwest for many of the reasons I have already stated.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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

J. Charles Smith
Utility Wind Interest Group (UWIG)
PO Box 2671
Springfield, VA 22152 USA
(703) 860-5160
jcharlessmith@comcast.net

Edgar A. DeMeo
Renewable Energy Consulting
Services Inc. (RECS)
2791 Emerson Street
Palo Alto, CA 94306 USA
(650) 327-3090
edemeo@earthlink.net

Brian Parsons
National Renewable Energy
Laboratory (NREL)
1617 Cole Blvd.
Golden, CO 80401
(303) 384-6958
brian_parsons@nrel.gov

Michael Milligan, Consultant
National Renewable Energy
Laboratory (NREL)
1617 Cole Blvd.
Golden, CO 80401
(303) 384-6958
michael_milligan@nrel.gov

Presented at the
American Wind Energy Association Global WindPower Conference
March 28-31, Chicago, Illinois

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

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.

References

1. Brooks, D., Lo, E., Zavadil, R., Santoso, S., Smith, J.; Characterizing the Impact of Significant Wind Generation Facilities on Bulk Power System Operations Planning. UWIG, May 2003.

2. Dragoon, K., Milligan, M.; Assessing Wind Integration Costs with Dispatch Models: A Case Study. Windpower 2003, Austin, TX.

3. Hirst, E., Integrating Wind Energy with the BPA Power System: Preliminary Study. Prepared for BPA Power Business Line, September 2002.

4. Hirst, E.; Integrating Wind Output with Bulk Power Operations and Wholesale Electricity Markets. Wind Energy 2002; 5(1): p. 19-36.

5. Electrotek Concepts, Inc; Systems Operations Impacts of Wind Generation Integration Study. Prepared for We Energies, June 2003.

6. GRE Wind Integration Study, presented at UWIG Technical Workshop, Seattle, WA; October 2003.

7. Parsons, B., Milligan, M., Zavadil, R., Brooks, D., Kirby, B., Dragoon, K., Caldwell, J.; Grid Impacts of Wind Power: A Summary of Recent Studies in the United States. European Wind Energy Conference, Madrid, Spain; June 2003.

8. RPS Integration Methods Group (B. Kirby, M. Milligan, D. Hawkins, Y. Makarov, K. Jackson, H. Shui). California Renewable Portfolio Standard Renewable Generation Integration Cost Analysis. Phase 1: One Year Analysis of Existing Resources, Results and Recommendations; December 2003.

Ancillary Services Cost Comparison

Study	Relative Wind Penetration (%)	Regulation $/MWh	Load Following $/MWh	Unit Commitment$ /MWh	Total $/MWh
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	N/A	1.64	3.00	4.64
BPA/Hirst	7	0.19	0.28	1.00-1.80	1.47-2.27
PJM/Hirst	0.06-0.12	0.05-0.30	0.70-2.80	N/A	0.75-3.10
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 Energy I	4.3				3.19
Great River Energy II	16.6				4.53
CA RPS Phase I	5	0.17	0	N/A	0.17
MN DOC/Xcel	15	0.23	0	4.37	4.60

tabbies EXHIBIT 2