NORTHWEST WIND INTEGRATION

ACTION PLAN

Working Draft to Policy Steering Committee
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ACKNOWLEDGMENTS

Steering Committee Members

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INTRODUCTION

The Pacific Northwest, already blessed with abundant hydroelectricity, is now seeing rapid growth in another of its renewable energy resources – wind power. Since 1998, with the installation of the 25 megawatt (MW) Vancycle project in Oregon, more than 1,400 MW of wind projects have come on line. Another 360 MW are scheduled to be online in 2007, and another 1,200 MW are expected by 2009 for a total of nearly 3,200 MW of wind power in the Northwest. In its Fifth Power Plan, the Northwest Power and Conservation Council identified up to 6,000 MW of developable wind power in the Northwest over the next 20 years.

A variety of factors are shaping this growth, including policy developments at the federal, state and local levels. Among recent developments:

- Western governors have called for 30,000 MW of clean, diversified energy in the Western Interconnection by 2015.
- Washington's electorate adopted Initiative 937 last fall, mandating a 15 percent renewable portfolio standard for the majority of load in the state by 2020.
- The Oregon Governor's Renewable Energy Task Force has recommended that Oregon adopt a renewable portfolio standard of 25 percent by 2025.
- The federal Wind Energy Production Tax Credit has been extended through 2008 and is likely to be extended again.

Other variables, including the high and volatile price of natural gas, and the potential for legislation limiting carbon emissions, indicate that wind energy is going to play a major role in the future of the Northwest power system.

In this policy and market environment, the challenge facing Northwest utilities and others in the energy community is to develop a solid understanding of the role of wind energy in the Northwest power system, and to then take steps to maximize the economic and environmental value of the resource at the lowest overall cost to regional ratepayers.

Wind energy is going to play a major role in the future of the Northwest power system.

Through this Northwest Wind Integration Action Plan, the Northwest Power and Conservation Council, the Bonneville Power Administration (BPA) and many other participating utilities and organizations have sought to address the important questions surrounding the growth of wind energy. These questions include:

- What is the role of wind energy in a power supply portfolio, and how does wind energy impact system operations and system flexibility?
- Does the Pacific Northwest have the physical capability to integrate up to 6,000 MW of wind? What are the estimated costs of integrating this amount of wind energy?
- What are the short-term and longer-term transmission requirements for developing 6,000 MW of wind?
- How will the costs of wind integration be recovered?

- How can we work together to help the region meet its wind energy potential at the lowest overall cost?

A Technical Work Group, formed to draft the Wind Integration Action Plan, has completed the first phase of its analysis. This report describes the initial findings on these major questions, and provides recommendations for specific actions and further analysis in 2007-2008.

SUMMARY OF FINDINGS

Operational integration capability and initial cost estimates

Wind power is a zero-emission energy resource. Wind's fundamental value to a utility portfolio lies in its ability to reduce fossil fuel consumption, limit exposure to volatile fossil fuel prices, hedge against possible greenhouse gas control costs, and deliver benefits of short lead time.

Because of its natural variability, wind power provides only a limited amount of sustained peaking capacity to a utility system. As a result, with or without wind energy, the Northwest will need to build firm capacity resources to meet peak load requirements. In other words, load requirements, not the growth in wind energy, will drive the need for additional peaking capacity. Wind energy is added as a renewable, clean energy resource to lower the fuel consumption of these capacity resources and help secure the environmental and economic benefits of lower fossil fuel emissions.

The variability and uncertainty of wind energy, when combined with the natural variability and uncertainty of loads, creates a modest increase in the demand for operating reserves required to maintain system balance. Larger utilities with sufficient flexibility in their systems will be able to secure these additional reserves through changes in system operation and secondary marketing activities. Utilities lacking sufficient incremental flexibility will need to purchase additional operating reserves or shaping services from others or invest in new resources. The direct and opportunity costs of these changes and/or flexibility purchases will need to be appropriately recovered. Over time, utilities may simultaneously meet their incremental needs for peaking capacity and operating reserves by ensuring that new capacity additions have sufficient maneuverability to manage all or a portion of the incremental system variability associated with their wind resources.

The NWIAP technical workgroup reached general agreement on the appropriate analytical approach to quantifying the incremental amount of regulation and load following capability necessary to integrate large amounts of wind. Three Northwest utilities — Avista, Idaho Power and BPA — have adopted this approach in individual wind integration studies that reflect the unique characteristics of their systems. These recent studies build on previous wind integration work performed by Puget Sound Energy (2003) and PacifiCorp (2001)[1]. The Avista and Idaho Power Studies examine wind energy impacts across the within-hour and hour-to-hour time horizons. Both studies are being peer reviewed and will be submitted for Public Utility Commission review in the near future.

The BPA analysis is more preliminary in nature. It primarily looks at within-hour impacts of wind on system operations. Given the rapid growth of wind energy projects interconnecting into the BPA system to serve non-federal loads, this was deemed by the federal agency as its highest priority for the first phase of this project. In the following phase, BPA will continue to revise its cost estimates and analyze wind impacts on its hour-to-hour operations. In addition, BPA will refine its analysis and pricing of storage and shaping products to assist its customers and other

1 The results of these studies will be summarized in Chapter 2, Operational Integration Capability and Cost Estimates.

third parties that do not have sufficient resources to cost-effectively manage the hour-to-hour variability of their wind resources.

Although the recent regional studies show costs comparable with studies done in other regions, they can not necessarily be generalized to other Northwest utility systems. The aggregate cost to the "region" cannot be determined at this time, due to the diversity in the size of utilities and uncertainty over where the wind will be developed. However, based on initial studies, no fundamental technical barriers to achieving the Council's target of 6,000 MW of wind from the perspective of power system operations were found.

System flexibility is not evenly distributed among regional utilities. As a result, more liquid bilateral markets, or other means of transferring this capability among control areas, are needed to ensure the existing balancing capability is fully available and is used in the most cost-effective manner.

As the flexibility of the hydro system is taxed by additional wind, load growth, and other limitations, it increasingly will be beneficial to be able to access the sub-hourly maneuvering capability of the rest of the generators in the region. Similarly, methods that share variability among control areas will increase reliability while reducing costs, with or without wind. These tools can be developed through bilateral or multilateral agreements.

The initial cost estimates are as follows:

[These will be officially included when the peer review process is concluded in late January/ early February.]

The Northwest does not possess sufficient wind data to produce a highly detailed representation of the operating characteristics of a 6,000 MW wind fleet. It is statistically invalid to scale up the output of currently operating wind projects to represent a larger aggregation of projects, because this will not capture the dynamics of spatial diversification and smoothing that may materialize with a larger wind fleet. In addition, a high-quality wind data set requires time-synchronized wind and load data to capture meteorological forces that impact wind and loads simultaneously.

To address data concerns, we recommend the development of a synthetic high-resolution chronological wind resource dataset for the Pacific Northwest.

While the capacity value of wind power was of little concern when wind comprised a small fraction of system capacity, the increasing penetration of wind power has heightened the importance of correctly assessing its capacity value. By 2009, wind is expected to comprise over 6 percent of installed capacity and will likely continue to grow. The Northwest Resource Adequacy Forum has assigned a provisional 15 percent sustained capacity value to wind for evaluating the performance of the regional power system with respect to the pilot capacity targets. Little data or analysis underlies the provisional value and the Resource Adequacy Forum has called for further assessment. Based on data from recent peak load events, the Technical Work Group believes that the 15 percent capacity value for wind may be too high and

recommends the value be formally assessed when sufficient data is available to do so with greater confidence.

Forecast near-term demand for new wind power

The forecast near-term (2007 through 2009) regionwide expected demand is for 1,200 MW of wind power, with high and low bounds of 2,200 and 1,100 MW, respectively.2 These amounts would lead to a total regionwide operating wind capacity by the end of 2009 of about 3,200 MW in the expected case, 3,800 MW in the high case, and 2,700 MW in the low case. These amounts would represent about 5,6, and 7 percent of total regional generating capacity respectively.

Short-term and long-term transmission requirements for integrating 6,000 mw of wind energy

The lack of incremental, long-term firm transmission capacity on the regional transmission system has been a persistent problem over the past few years. It is becoming particularly acute in the wind resource areas east of the Columbia River Gorge, where hundreds of megawatts of wind capacity are under construction and thousands of megawatts of new wind capacity are proposed. With creativity and regulatory support, the development of 6,000 MW or more of wind can be accomplished without megawatt-to-megawatt of transmission and wind capacity. Achieving this result will require some combination of transmission expansion, new commercial practices and new regulatory policies to facilitate efficient delivery of wind power to load.

While long-term firm transmission capacity is sufficient to serve the medium near-term (2007 through 2009) forecast of wind project construction (1,200 MW), it may be inadequate if the high-case, near-term forecast materializes and is clearly inadequate for 6,000 MW, or more of long-term development. It is the choice of resources remote from the load centers in the I-5 corridor (as contrasted with energy efficiency or distributed generation), whether they be wind, gas or coal, that compels regional transmission expansion. But the more remote geographic location of some wind rich areas makes transmission expansion a significant issue if some wind resources, for example from Montana and Wyoming, are to be available to the Pacific Northwest.

In any event, the current queue of transmission interconnection requests (an amount greater than the forecast of near-term demand) has exhausted the availability of *long-term firm* transmission capacity on Bonneville's system. This fact alone suggests the need to examine transmission adequacy on the Bonneville system now, if the region is to keep open the option of integrating substantial wind energy in eastern Washington and Oregon, which is an integral part of the estimated 6000 megawatts of wind energy resources.

A proposed two-phase reinforcement of BPA's main grid transmission network from McNary west towards The Dalles, will greatly expand transmission capacity from eastern Washington and Oregon wind resource areas to load centers west of the Cascades. This expansion may create

[2] Staff of the Northwest Power and Conservation Council and the Bonneville Power Administration prepared a forecast of wind power development to support the development of the Northwest Wind Integration Action Plan. This was a demand-based forecast, based on the integrated resource plans and current resource requests for proposals of Northwest utilities, plus an allowance for out-of-region demand driven by the California renewable portfolio standard.

ancillary benefits. These include access to higher-quality wind resource areas that produce high-capacity factors and lower busbar costs. The resulting more geographically diversified array of projects should reduce the probability of extreme ramping events, improve aggregate wind forecasting accuracy, and reduce the need for additional operating reserves to integrate wind. The reinforcements will improve operating margins on the transmission system as a whole. Finally, a successful financing and construction process would demonstrate the region's ability to resolve transmission issues, and will serve as precedent for further transmission upgrades when needed. For all of these reasons, we recommend that BPA aggressively pursue the West of McNary reinforcement project, although we are cognizant of the limitations on the BPA's borrowing authority.

Unfortunately, the West of McNary reinforcements are expected to require four years to complete. New products such as conditional firm service and generation redispatch could provide interim or permanent opportunities for additional wind project interconnections by using existing transmission as efficiently as possible. We recommend that BPA develop and test a pilot conditional firm transmission product, and a pilot voluntary generation redispatch program using Federal and non-Federal resources, with the initial objective of using existing West of McNary transmission as effectively as possible.

While the traditional utility paradigm requires firm transmission for the full output of a generating plant, this is not efficient for an intermittent resource. A wind plant with 33% capacity factor essentially triples the cost of transmission. The Region should develop a transmission expansion model that uses the tools above to determine a mix of firm, nonfirm and/or conditional firm to deliver wind efficiently. This will ensure that transmission is expanded only when appropriate.

Prerequisite to constructing the West of McNary reinforcements is a financing mechanism for projects that, like this, are largely market-driven. The financing paradigm must address the Catch-22 confronting many wind project developers. They cannot make financial contributions to a new transmission line unless they have security in the form of a power purchase agreement; yet they typically cannot secure a power purchase agreement without a long-term transmission service agreement. We recommend that BPA continue its development of an approach for financing and recovering the costs of the proposed West of McNary transmission project, seeking a model that could be adapted to other transmission projects.

Certain utility regulatory policies discourage investment in the transmission grid. Utilities and the state regulatory commissions should review transmission cost recovery policies to ensure that they are consistent with transmission products, and that transmission expansion financing models are structured to provide adequate incentives to investor-owned utilities participating in transmission expansion projects.

New generation in the I-5 corridor will significantly increase congestion on these paths. Proposed wind generation exacerbates the problem. In addition, the need for additional Cross Cascades transmission may be accelerated if dispatchable west side resources are turned down in response to wind availability during peak load periods. The immediacy of these problems

suggests that Plans of Service be developed first for I-5 Corridor and subsequently for Cross-Cascades reinforcement.

Finally, we believe that additional transmission system upgrades and expansions may be desirable in the longer-term to channel new wind development to the most cost effective sites. Studies should be undertaken of the feasibility and cost of extending transmission capacity to Montana and other prime regional wind resource areas that offer geographic diversity, better capacity factors and better coincidence to loads. While the discussion above focuses on the Bonneville system, investments may be required by other transmission owners in Oregon, Washington, Montana and Idaho.

Cost recovery and allocation of wind integration costs

Currently, transmission providers such as BPA and NorthWestern Energy recover the cost of acquiring operating reserves to maintain system balance by charging loads in their own control areas for Regulation and Frequency Response service. When wind generation is located in a host control area, yet serves loads outside the host control area, the loads within the host control area still pay the costs of any additional operating reserves requirement caused by the wind generation, unless other agreements have been negotiated between the two control areas, such as dynamic scheduling.

Over time, transmission providers may find that they are incurring a significant increase in regulation and load following requirements that may be attributable in part to the interconnection of wind generation. In such cases, we recommend a thorough evaluation of all sources of within-hour variability from loads and resources in these control areas to determine the contributing factors for system operating reserve requirements.

In addition to this evaluation, the tariff provisions for allocating costs among users of the system should be tested to see if there is a reasonable cost-causation linkage between users who add to system requirements, and those who pay the charges associated with these requirements. If the current tariff no longer fairly allocates those costs, the tariff should be revised appropriately.

Working together to help the region develop its wind energy potential at the lowest overall cost

A diverse set of cooperative actions were identified to further extend integration capability and help the region meet its wind energy potential in the most cost-effective manner possible. Some of these actions will address pressing needs -- such as extending the availability of system flexibility services to utilities throughout the region -- whereas others -- such as a regional wind forecasting network -- are optional, but of potential value in minimizing costs.

These actions should commence with forming an organization to oversee all of the actions recommended in this report. The organizational model adopted for the first phase of work – that of a Policy Steering Committee and a Technical Work Group with specialist subcommittees – is ideal for implementing the cooperative recommendations of this report. We propose that this effort be renamed the Northwest Renewable Resource Integration Forum to reflect the regional focus on implementing the actions recommended in this report, and the expectation that many of the integration issues confronted by wind will be common to other renewable resources. The Forum should continue for a period of at least two years with essentially the same structure and

membership to assemble the resources needed to accomplish the actions identified in this report: to ensure that the actions are completed in a timely manner; to provide oversight, review and publication of work products; and to periodically review the recommendations to ensure that they remain current and pertinent.

The Northwest operates as 13 separate control areas, each responsible for balancing its own loads and resources. Currently under the Northwest Power Pool the control areas share responsibility for contingency reserves, reducing the requirements that individual operators would need to maintain on their own. A similar approach could be developed to address flexibility needs for managing wind. One such strategy is Area Control Error (ACE) Diversity Interchange under development by the Northwest Power Pool and expedited on a pilot basis by several Northwest utilities. We recommend that participants in the emerging ACE Diversity Interchange pilot provide the Northwest Renewable Integration Forum with a report on progress made in implementation. If promising, other Northwest utilities should consider the merits of participating.

A second area of beneficial operational cooperation is to expand the market for control area balancing products and wind integration services. Wider availability of these services will allow more control areas to integrate more wind; help smaller utilities purchase the output of wind projects; allow utilities to leverage the geographical diversity of their respective wind projects into lower individual balancing requirements; to leverage the daily and seasonal differences in system flexibility among the region's utilities, and help further reduce the probability of having to limit wind generation output during periods of hydro constraints.

BPA's Requirements Customers are likely to purchase more wind energy over time to meet renewable portfolio standards and other objectives. Through the Regional Dialogue process and other forums, they will need a clear understanding of the types of services required – and their availability – to use wind energy as a Tier-2 resource to meet incremental load growth.

The development of a regional wind forecasting network may be of potential value in increasing the accuracy of forecasts for all participating wind projects, as well as providing more accurate forecasts for entire Balancing Areas. Structuring such a network to be consistent with the needs of system operators and developers is essential.

Although our initial analysis indicates that the Northwest has the physical capability to operationally integrate 6,000 MW of wind, there will be occasional periods when large, unexpected changes in wind output coincide with limited system flexibility. Under certain circumstances, the most cost-effective way of managing this situation may be to limit wind project ramp rates or output for brief periods until system operating reserves are sufficient to resume control. Wind project output control would be implemented through the interconnection agreements between project owners and transmission providers. FERC, in its Appendix G of its standard Large Generator Interconnection Agreement, now requires that wind plant operators secure the capability to transmit data and receive instructions from the transmission provider to protect system reliability. BPA is planning to conduct a series of workshops in 2007 to develop a framework for implementing Appendix G. Because limitations on wind output will impact wind project economics, we recommend that BPA work with wind developers, and through a rigorous

cost/benefit analysis, seek to achieve the objectives of Appendix G in the most cost-effective manner possible.

A large portion of the region's hydro flexibility is provided by Mid-Columbia complex of dams. Optimizing the operation of these resources will increase their economic value and combined flexibility. In recent years, parties have been working collaboratively to resolve issues that have prevented the Mid-C complex from operating as efficiently as might be possible. Parties to the Mid-C Hourly Coordination Agreement should continue their efforts to resolve outstanding technical and operational challenges and should identify specific strategies that could enhance total flexibility for wind integration and other purposes. Other bilateral or multilateral resource sharing agreements should be examined in a similar light.

Although there are steps we can take today to preserve and potentially enhance hydro system flexibility, this flexibility may diminish over time as a result of load growth and other factors. Some regional utilities are already investing in new capacity resources, such as natural gas turbines, which will also be able to help manage system variability. In fact, for the foreseeable future, the costs of wind integration are likely capped at the capacity and energy cost of combustion turbines running on fixed price natural gas. There are also other existing and emerging sources of system flexibility and storage including pumped hydro and compressed air storage, batteries, demand response and other approaches that may become more applicable and cost-effective in the Northwest over time. It is reasonable to start exploring these options, investing R&D dollars in promising emerging technologies, and looking for ways to deploy them in a least-cost, environmentally sustainable fashion.

Wind development in the Northwest to date largely has been localized east of the Columbia River Gorge, driven by the coincidence of favorable wind resources, suitable land use and available transmission in this area. Opportunities may exist, however, to improve the cost effectiveness of wind power through extending transmission to currently isolated wind resource areas and developing new sources of system flexibility and shaping and storage technologies. The recommendations of this Wind Integration Action Plan will provide the information needed to assess the tradeoffs between transmission, system flexibility and storage and shaping, leading to a long-term strategy for maximizing the economic and environmental value of wind. We recommend that a comprehensive assessment of possible strategies be undertaken for the Northwest as an element of the Council's Sixth Power Plan.

SUMMARY OF RECOMMENDATIONS

The above findings and conclusions have led to the following recommendations. Lead organizations have been identified where obvious. Identifying lead organizations for the other recommendations will be the responsibility of the proposed Northwest Wind Integration Forum.

Operational integration capability and initial cost estimates

(A) Refine estimates of operating reserve requirements & wind integration costs using improved wind resource data. *Moderate priority, complete 2008.*

(B) Develop a three-year, high resolution, 10-minute, chronological Northwest wind speed and power data set. *High priority, complete EOY 2007.*

(C) Formally assess the sustained peaking capacity value of wind in the Northwest. *Moderate priority, complete EOY 2008.*

Short-term and long-term transmission requirements for integrating 6,000 MW of wind energy

(A) The region should develop a transmission expansion model that uses the tools described below to determine a mix of firm, non-firm and/or conditional firm transmission service to deliver wind at the lowest overall cost *(High priority, complete 2007).*

(B) BPA should finalize the plan of service, and review the plan and business case for the West of McNary Reinforcement with the Infrastructure Technical Review Committee. *High priority*

(C) BPA should work with project developers, customers and other interested parties to develop and test a pilot conditional firm transmission product. *High priority*, complete 2007

(D) BPA should complete its reliability redispatch pilot program, and begin development of a voluntary redispatch program using Federal and non-Federal generation, to increase ATC on the West of McNary path. *High priority, complete 2007*

(E) BPA should develop an approach for financing and recovering the costs of the proposed West of McNary transmission reinforcement project, including commercially reasonable and feasible participation models for developers and other utilities. *High priority, complete 2007*

(F) Utilities and the state regulatory commissions should review transmission cost recovery policies to ensure that they are consistent with conditional firm service and new transmission expansion financing models. *High priority, complete 2008*

(G) Bonneville, in cooperation with regional stakeholders should develop a Plan of Service for I-5 Corridor Reinforcement.

(H) Bonneville, in cooperation with regional stakeholders should develop a Plan of Service for Cross Cascades Reinforcement

(I) Assess the feasibility and costs of extending transmission to other promising, but transmission-constrained wind resource areas such as Montana, including exploration of cooperative efforts among utilities and with independent transmission developers.

Cost recovery and allocation of wind integration costs

(A) If costs of balancing increase significantly, BPA and other Transmission Providers should review tariffs and rate structures to establish closer adherence to cost causation of system balancing needs for all resources and loads. *Conditional priority.*

Working together to help the region develop its wind energy potential at the lowest overall cost

(A) The Council, BPA and other interested parties should establish a Northwest Wind Integration Forum to carry out the recommendations of this Action Plan. *Highest priority, complete Q1 2007.*

(B) Participants in the ACE Diversity Interchange pilot should report on progress made in implementing the agreement. *High priority, complete July 2007.*

(C) The Technical Work Group should systematically address the transmission, scheduling, product design, regulatory, contractual and cost-recovery barriers to greater liquidity in the market for flexibility products and services.

(D) Bonneville Power Services should work with its customers and other interested parties to clarify uncertainty about the future cost and availability of wind integration services for its Requirements Customers, and work through the Regional Dialogue process to identify product requirements for using wind energy as a Tier 2 resource.

(E) The Technical Work Group should evaluate the costs and benefits of developing a regional wind forecasting network.

(F) The BPA should work with wind developers and other interested parties to implement Appendix G of FERC's Large Generator Interconnection Agreement, which governs communication and control requirements for wind turbines, in the most cost-effective manner possible.

(G) Seek improvements to use of hydropower system flexibility without adversely affecting non-wind uses of the system. *Moderate priority, complete 2008.*

(H) Parties to the Mid-Columbia Hourly Coordination Agreement should continue their efforts to resolve outstanding technical and operational challenges and should identify strategies to enhance flexibility for wind integration.

(I) The Council should host a workshop on the future of storage and other system flexibility technologies, and develop a work plan for identifying those technologies with the most promise of providing cost-effective flexibility to the Northwest power system. *Moderate priority, 2008*

(J) Assess the feasibility of a proactive, long-term regional strategy to maximize the economic and environmental value of wind power for the Northwest. *Moderate priority, initiate 2007.*

(K) BPA should explore and report on the feasibility of expediting relief from dynamic scheduling limits on interties to other control areas.

(L) Develop an integrated regional transmission plan under the auspices of Columbia Grid and Northern Tier Transmission Group that incorporates all utility identified resources including wind.

THE ROLE OF WIND ENERGY IN THE NORTHWEST POWER SYSTEM

This primer explains how wind fits into Northwest system operations and the variables that influence its economic and environmental value.

Appendix 2 provides a review of the technical terms and concepts related to operation of the Northwest power system.

Wind energy displaces fossil fuels and reduces exposure to price volatility

The primary purpose for adding wind energy to a power supply portfolio is to displace fossil fuel emissions and reduce exposure to natural gas price volatility. This is the main reason why utilities in Europe, with more than 30,000 MW of wind – 20,000 MW in Germany alone – have added such large amounts of wind to their systems. A bit closer to home, Southern California Edison, with 25 years of wind integration experience, explicitly refers to wind as a "fuel displacement resource." Historically, utilities have added resources to meet specific energy or capacity demand targets, whereas wind is primarily added for its environmental, economic, and risk reduction benefits.

An assessment performed by the Northwest Power and Conservation Council, indicates that a new must-run resource, such as wind generation will displaces natural gas more than 80 percent of annual hours, based on the existing system resource mix[3]. Coal is displaced about 10 percent of hours. During the remaining 10 percent of the hours, wind displaces other resource types. The economic and environmental benefits of this fuel displacement are a function of the heat rate and emissions control characteristics of the resource displaced by wind. This pattern is desirable (and logical) from an economic standpoint, since natural gas prices are higher and more volatile than coal (although coal prices and volatility have also increased in recent years). From an environmental perspective, however, it would be preferable to displace coal as opposed to natural gas. CO_2 reductions would be greater and it is likely that the reduction in criteria pollutants[4] would be greater as well.

Northwest wind characteristics

Winds are the result of atmospheric pressure differentials. These pressure differentials are the result of the unequal heating of the earth's surface. The unequal heating of the earth's surface at vary large spatial scales, such as the equator and the poles, results in large storm systems that can bring large pressure differentials, and their associated winds, to large geographic areas. The unequal heating of the earth's surface at smaller spatial scales, results in more localized pressure differentials that create more localized wind phenomena. These winds are often referred to as thermal circulation. Excellent examples of thermal circulations in the Pacific Northwest are the land/sea breeze on the coast and the winds in the Columbia River Gorge and other valley locations.

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3 Northwest Power and Conservation Council. "Power System Marginal CO2 Production Factors". Whitefish, Montana. April 2006.

[4] Oxides of sulfur, oxides of nitrogen, particulates, hydrocarbons and mercury.

In the Northwest, storm-driven wind resource areas have their highest wind output in the fall and winter months. Thermal circulations tend to be strongest during the summer months. This difference accounts for why some wind sites derive more of their annual energy in the winter months than the summer months, and vice versa. Some projects are driven roughly equal by both effects.

For the purpose wind power generation, a good wind resource area receives sustained strong winds averaging 7 m/s (16 mph), or more[5], ideally with daily and seasonal patterns coincident with electrical load. It will have smooth topography and low vegetation to minimize turbulence, sufficient developable area to achieve economies of scale, nearby transmission, complementary land use and absence of sensitive species, habitat, cultural features and aesthetic qualities.

Because of complex topography, land use and environmental limitations, only limited areas of the Northwest are suitable for wind power development. For example, wind power development in coastal areas with substantial land/sea breezes, as well as storm-driven wind activity, is likely to be severely constrained by steep topography, forest cover, aesthetic and other concerns. However, several excellent sites are found in other parts of the region (Figure 1).

Washington's Kittitas County, the Columbia River Plateau east of the Columbia River Gorge, and the Blackfoot area east of Montana's Marias Pass are excellent wind resources areas. Lands lying east of gaps in the Cascade and Rocky Mountain ranges receive concentrated prevailing storm-driven westerly winds, as well as wintertime northerly winds. Ridges perpendicular to prevailing winds in the Basin and Range areas of southeastern Oregon and southern Idaho receive strong winds. East of the Rockies, nearly any landform lying above the general elevation will have good winds. Gaps between local ranges, such as at Judith Gap in Montana, have concentrated wind. To date, wind power development has been concentrated in wind resource areas having access to transmission and favorable land use and environmental characteristics.

[5] At 50 m elevation

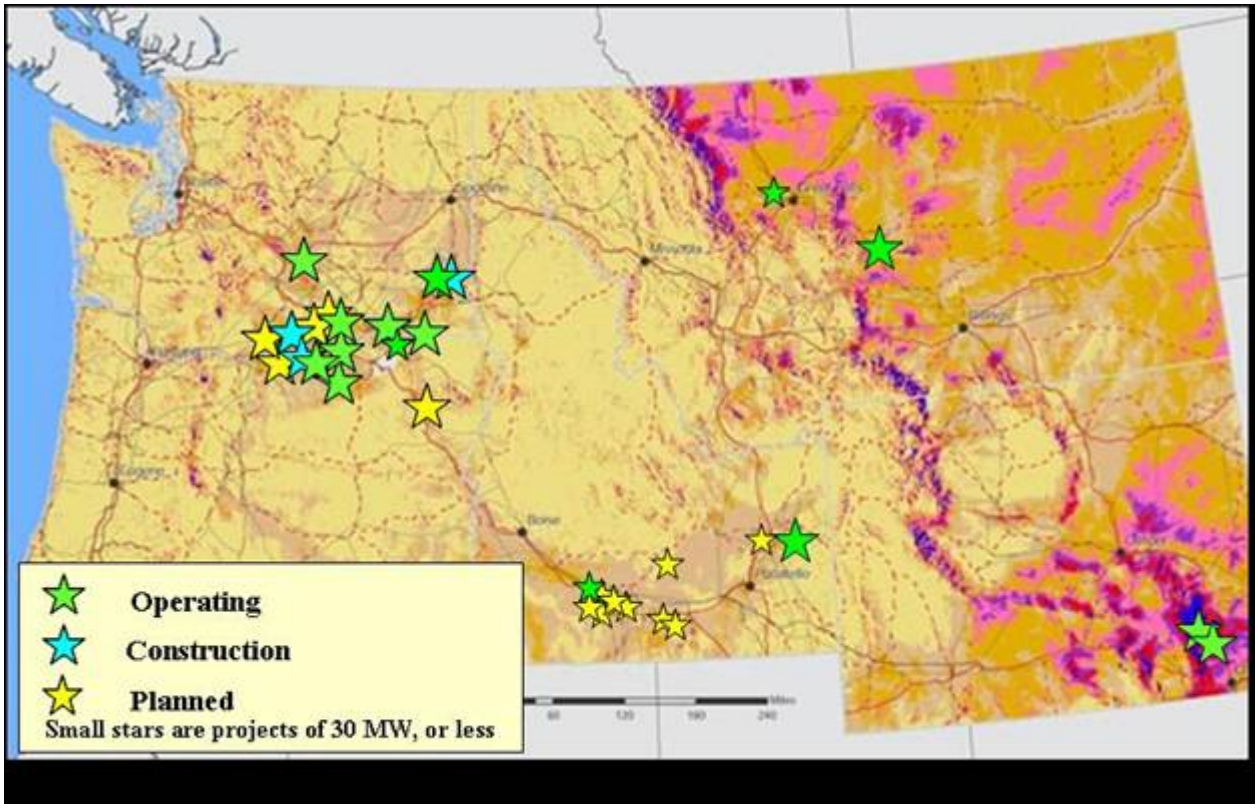

Figure 1: Northwest wind resources and wind projects

The atmospheric drivers of wind have implications for the Northwest during certain weather patterns, especially during the winter months. Periods of extreme low temperatures in the Pacific Northwest tend to occur when the region is affected by large-scale, high-pressure systems. These systems cause very little pressure variation across the region, and hence, an absence of wind. There is evidence that a similar phenomenon is seen during extreme heating events as well. The correlation between temperature and the availability of the wind is illustrated in Figure 2, using a limited set of data from four wind projects in the BPA system. The lowest availability of wind clearly occurs during times of especially high and low temperatures.[6]

[6] Additional data is needed to determine the extent to which such high-pressure systems can idle projects across the four-state region, and this question will be further explored in Phase 2 of this project. We also note that the latest generation of wind turbines tend to have higher capacity factors at lower wind speeds than the technology underlying this data.

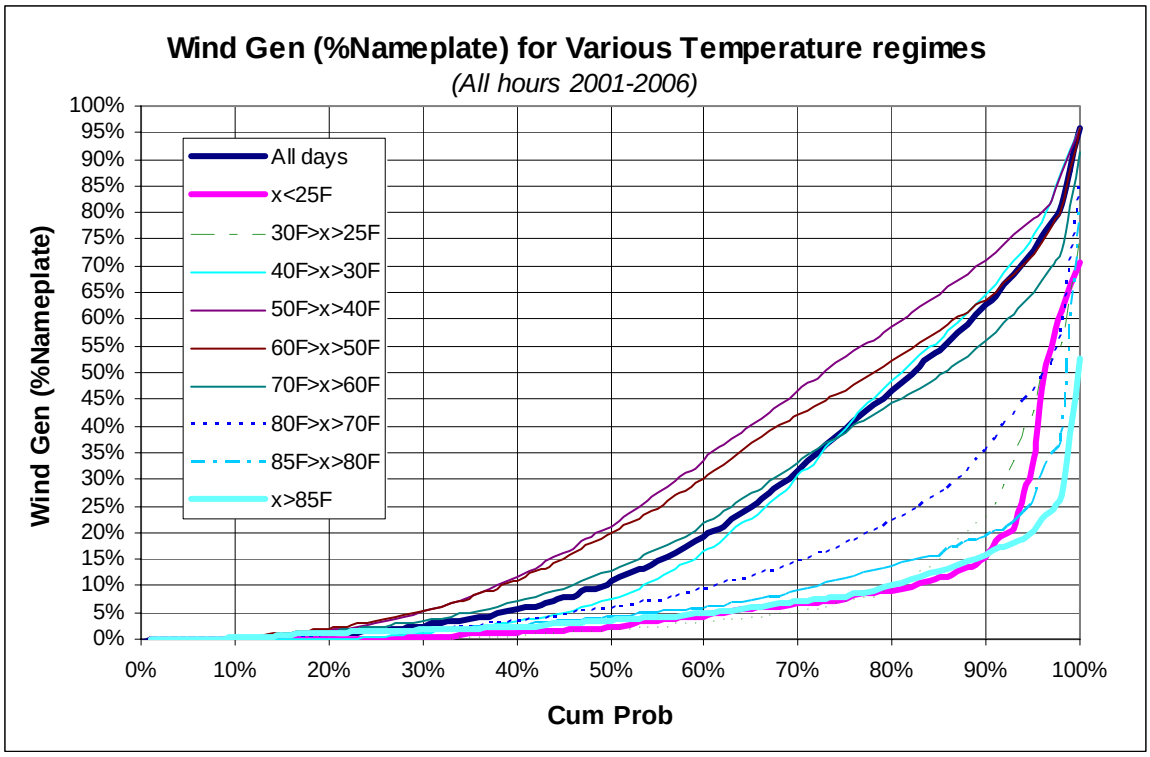

Figure 2: Wind production relative to load center (Portland, Seattle, Spokane) temperature (BPA Projects, 2001 - 2006)

The capacity value of wind

Since extreme heating and cooling events are frequently driven by high pressure weather systems and stagnant air, it can be expected that the contribution Northwest wind resources will make to meeting loads at those times will be less than their average capacity factor. For example, during the extreme heating event of July 24, 2006, the regional wind fleet as a whole generated at 5-10 percent of its nameplate capacity. On November 27, 2006, during the peak load hour of regional cold snap, the combined wind projects of BPA and Northwestern Energy generated at 3 percent of their nameplate capacity.

While these recent data points support the data in Figure 2, due to the short-term storage and shaping capability of the Northwest hydroelectric system, single-hour or daily peak period capability is not currently the limiting factor for system reliability purposes. Rather, it is the average generating capability over the peak periods of several days (sustained peak) that determines the capacity contribution of a resource in the Northwest.[7] The Northwest Resource Adequacy Forum's newly defined resource adequacy metric bases the sustained peaking capacity value of a resource on a 10-hour peak load period over five sequential days (the 50-hour sustained capacity). Compared to a single-hour peaking metric, this may increase the capacity

[7] Individual utility systems with less access to hydro resources may use different approaches to determining the capacity contribution for the wind in their portfolios.

value of wind generation because the average output of a wind project is likely greater for the sustained peaking period than for a single hour.

In 2006, the Resource Adequacy Forum assigned a provisional 15 percent sustained capacity value to wind generation for the purposes of regional system reliability planning. This number will be thoroughly evaluated with new wind resource data in 2007 to determine if it is a reasonable value. However, even at 15 percent, the relatively low capacity value of wind implies that other firm, dispatchable resources (thermal, renewable or demand side) will be required to ensure regional reliability during peak load periods and to meet incremental load growth. Wind will serve as a complementary *energy* resource to this firm capacity.

As discussed below, this does not mean that changes to Control Area operations will not have to be made with more wind, or that additional costs will not be incurred. However, it is essential to understand that peaking capacity is essentially a fixed obligation of system operation – necessary with or without wind – and that the relatively low capacity contribution of wind does not negate the fundamental value proposition of wind energy: it displaces fossil fuel emissions and reduces exposure to natural gas price volatility.

Wind energy behaves like negative load and increases net system variability and uncertainty

Not only does wind demonstrate few of the attributes of a capacity resource, the moment-to-moment and hour-to-hour variability of wind makes it behave much more like a *negative load* than a traditional source of generation. In fact, as was said by one of the members of the Technical Working Group's System Operators Committee, "There is nothing about wind energy that is *fundamentally* different than anything we have been dealing with on the load side for many years."[8]

When one views wind generation as negative load rather than as a source of generating capacity, its impacts on system operation become easier to understand. All utility systems are designed with the flexibility necessary to manage the natural variability and forecast errors associated with their loads. This variability and uncertainty can be substantial. The BPA system and others regularly deal with changes in load of several thousand megawatts during the morning and nighttime ramps. Under the vast majority of conditions, our systems manage these changes without difficulty. Given that even the most dispatchable of power generation technologies also have some variability associated with their output, the objective of Control Area operations is to manage net *system* variability and net *system* forecast error. When wind energy is added to a utility system, its variability and uncertainty becomes part of this net system variability and uncertainty.

At low levels of wind penetration in large utility systems, the incremental impacts of wind on system variability and uncertainty are very small and difficult to quantify. This is because the variability and uncertainty of wind is small compared with the variability and uncertainty in

[8] We do note, however, that one megawatt of new wind is more variable and less predictable than one megawatt of new load.

existing power systems. However, as the amount of wind in the system increases, the impacts become more noticeable, and the ranges of net system variability and net system forecast error increase. This places additional demands on system flexibility across two main time horizons: within-hour (1-60 minute) and hour-to-hour. We begin with a discussion of within-hour impacts and then follow with hour-to-hour impacts.

The variability across both these time horizons is portrayed in Figure 3.

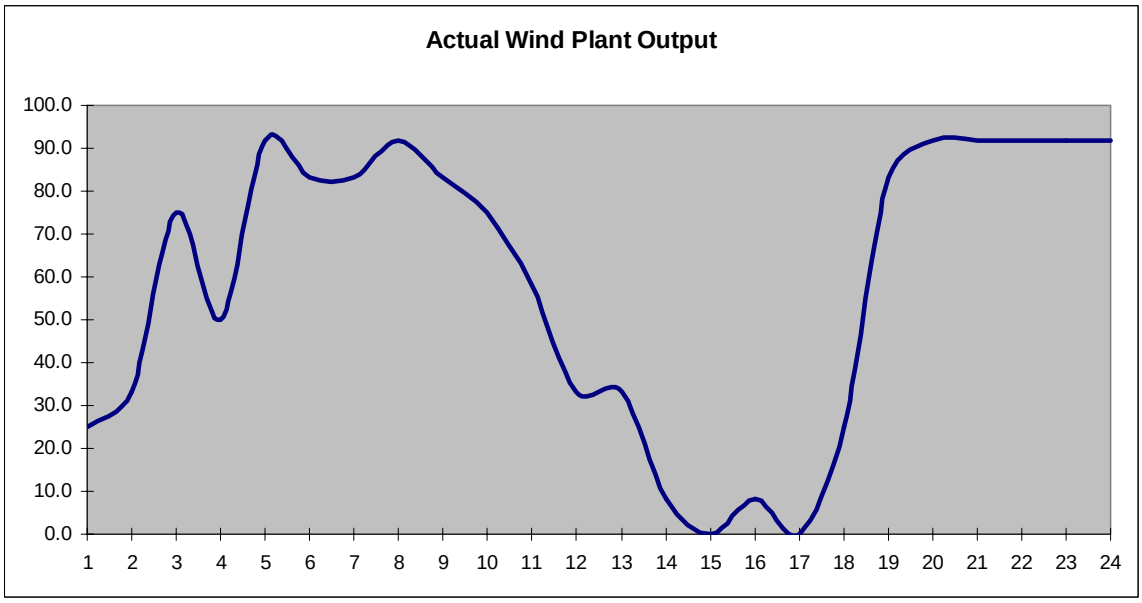

Figure 3: Representative diurnal output of a wind plant

Within-hour wind integration and hour-to-hour shaping

Wind energy in the within-hour time frame

In the within-hour time frame, wind increases the demand for additional regulating (several second response time) and load following (several minute response time) reserves. Control Areas carry regulating reserves to manage the minute-to-minute changes in load/resource balance. Northwest utilities also carry "load following" reserves to maintain system balance across the remainder of the scheduling period (60 minutes in the Northwest). Regulation and load following reserves are a subset of Operating Reserves, which also include contingency reserves, which are carried against sudden unplanned outages of generation and transmission elements.[9]

Figure 4 illustrates the within-hour behavior of a limited data set of four wind projects in the BPA system. The projects comprise about 440 megawatts of installed capacity (not all of which is integrated by BPA). The figure depicts the distribution of wind output changes over the 1-minute, 10-minute and 60-minute time horizons. As can be seen, for all 3 series, the variability is clustered around zero with limited amounts of probability in the tails of the distributions.

[9] Under current rules, wind projects are treated like hydro resources from the perspective of contingency reserves and there is no incremental demand for contingency reserves associated with increased wind generation.

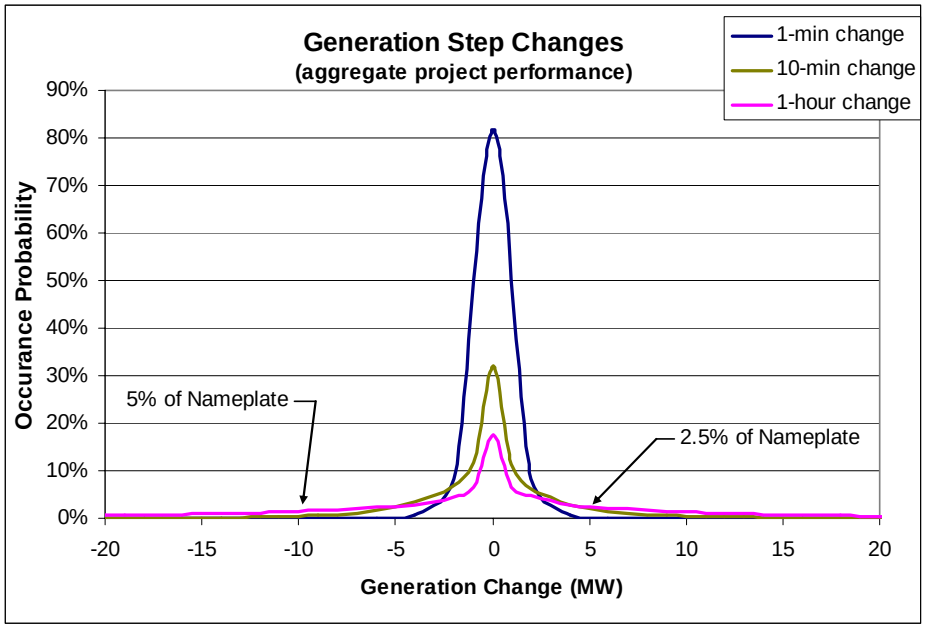

Figure 4: Short-term generation step changes for 4 projects in the BPA Control Area

It is evident from Figure 4 that 1-minute and 10-minute step changes are typically smaller than 60-minute step changes. In fact, the incremental amount of within-hour *regulating* reserves required to manage wind energy – even for a large wind fleet – is quite small compared to existing requirements. This is because the output of wind projects seldom changes dramatically over very short time intervals and the output of wind turbines – even in individual wind projects – is uncorrelated across the regulating time frame. Changes in wind turbine output across the 10 to 60-minute time frame are larger and more correlated within individual projects. Changes in wind power output over this time horizon are a larger driver of the incremental demand for within-hour balancing reserves.

Whereas wind has a certain amount of natural variability associated with its output, it is the challenge of predicting this variability that drives the uncertainty associated with wind. Like wind variability, wind forecast errors also have a distribution associated with them, and ideally, they should be evaluated in combination with the other sources of forecast error in system operations, especially load forecast errors.

BPA evaluated the forecast errors of four of its wind projects from 2001-2006 and found the following distribution in Figure 5:

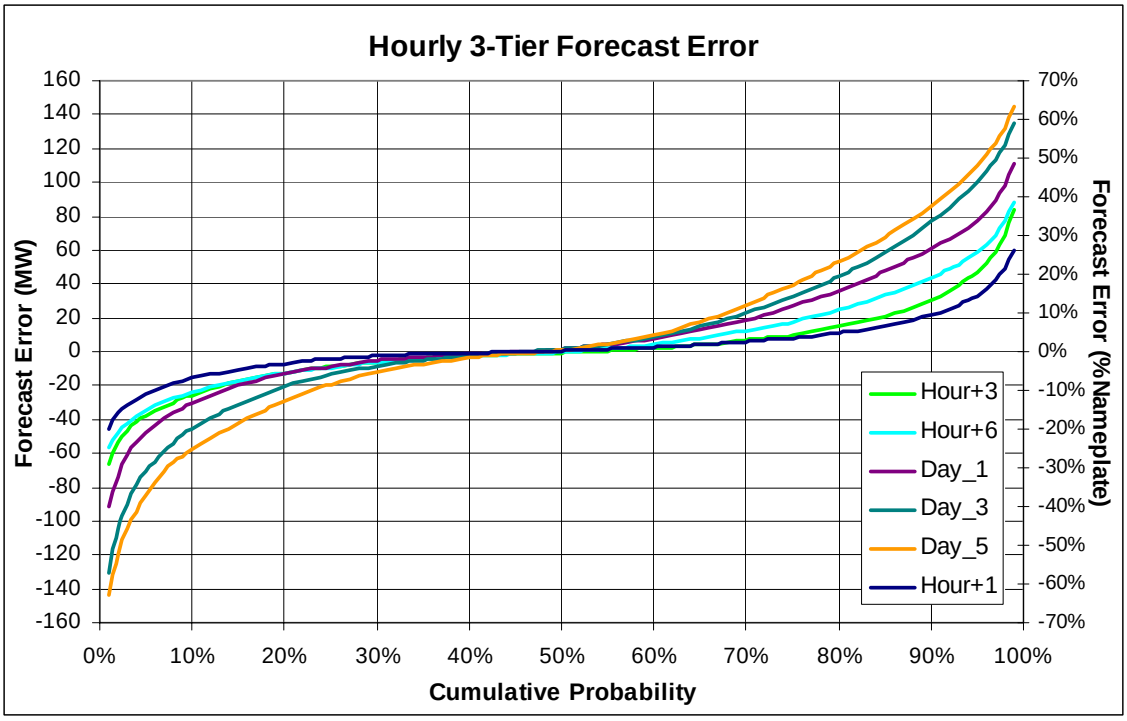

Figure 5: Distribution of forecast errors for BPA wind projects

As can be seen, the quality of wind forecasts for this limited data set improves dramatically from 5 days ahead to 1 hour ahead. For the 1-hour ahead forecast, 90 percent of the time, the wind forecast error varies between minus 25 percent and +30 percent. These uncertainties are partially mitigated by combining wind and load forecasting.

As a result of the forecast error associated with wind, utilities must carry an additional increment of reserves to ensure that they have sufficient maneuverability in their systems if actual wind deviates from its forecast for the hour. Good wind forecasting is an essential element of managing wind power and mitigating the costs of wind integration. It will be an essential operational tool for all utilities with wind on their systems.

Northwest system operators must have access to sufficient regulation and load following reserves to balance their systems net of the incremental variability and uncertainty created by wind. Utilities with sufficient system flexibility will be able to secure the incremental operating reserves simply by changing how they operate their existing fleet of assets. Examples include running units out of economic merit order, and placing generating capacity that would otherwise be used for short-term secondary marketing onto reserve status. Where and if flexibility becomes exhausted, utilities will have to procure flexibility from neighboring Control Areas, or call on new generating, demand-side, or storage capacity capable of providing operating reserves.

Northwest utilities currently rely entirely on their own generating resources or those under contract with other Control Areas to manage the within-hour variability of their systems. In other regions of the country with shorter-term balancing mechanisms, Control Areas have access to a deeper supply of resources to help provide the needed maneuverability. This can facilitate

savings in within-hour balancing costs. Within-hour balancing mechanisms also enable utilities to take better advantage of the more accurate wind forecasting for shorter time horizons.

Until other cost-effective sources of regulation and load following capability can be incorporated into within-hour system operations, the Federal Columbia River Power System (FCRPS) and other Northwest hydro facilities will meet their need for additional operating reserves by running hydro facilities more at night and marketing less during peak periods. Since the primary economic objective of hydro operations is to conserve water for release during the most valuable time periods (usually the peak load hours of the day), this will shift hydroelectric generation from peak to off-peak load periods, creating opportunity costs.

Regulating and load following reserves essentially "firm up" the output of wind energy projects during the hour. In vertically disaggregated utilities operating under the provisions of FERC Open Access tariffs, these within-hour services are supplied by the transmission side of the business and sold via transmission service agreements. The authors of this report have begun to apply the term "wind integration" to this process of managing the within-hour impacts of wind energy.

Given the geographic footprint of the BPA, it is likely that many wind projects intended for non-federal load service will continue to seek interconnection agreements with BPA Transmission Services. There are 500 MW of such projects integrated into the BPA system today, and this figure is expected to increase by several hundred MW in 2007. Absent other agreements, by virtue of their location in the BPA Control Area, these projects will draw on the within-hour regulation and load following capability of the FCRPS. Given BPA's statutory obligations, the Agency will have to evaluate the financial impacts of these balancing reserve requirements. It will also have to ensure that cost recovery mechanisms are in place to mitigate financial impacts on its Requirements customers from sales of balancing services to non-federal entities. We anticipate that other utilities may also face this issue and it is discussed further under Cost Recovery and Allocation in the Findings and Recommendations section of this report.

Wind Energy in the hour-to-hour time frame

Utilities must also manage the hour-to-hour variability and uncertainty of wind output. Figure 6 depicts the shape of hourly wind output after it has been "firmed up" through within-hour integration by the transmission provider.

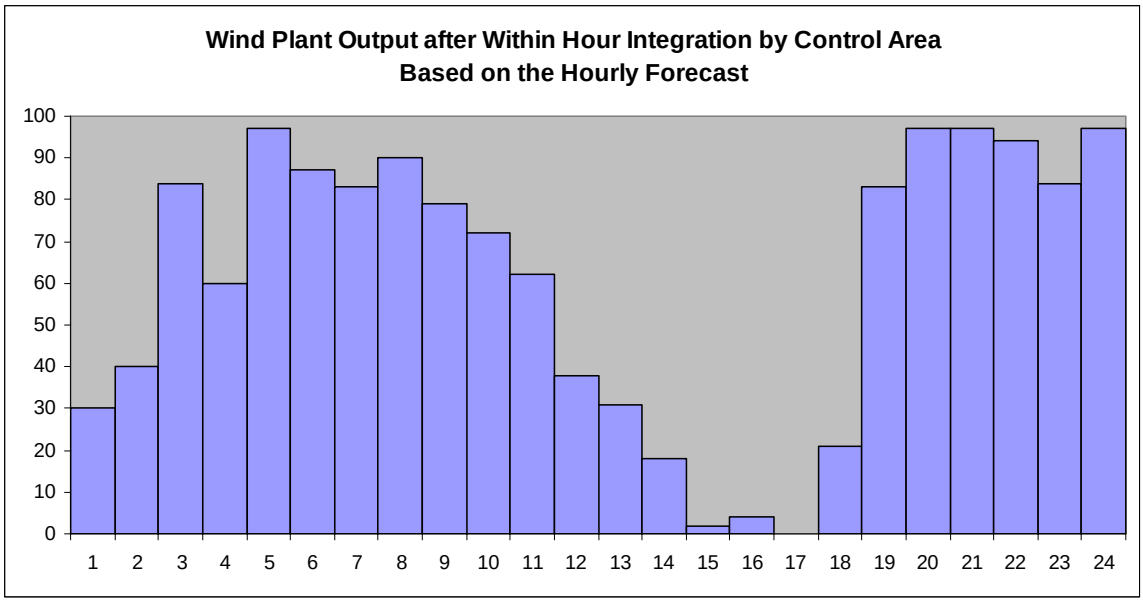

Figure 6: Wind output after within-hour firming by a transmission provider

These aggregate changes in hourly output are managed by the power side of the business through the dispatch of generating assets or by the use of balancing purchases and sales. For larger utilities with sufficient flexibility and access to the energy market, these hour-to-hour changes may have little additional impact on system operations. However, smaller utilities and developers with less access to flexible generating resources may need to purchase additional services to help manage this hour-to-hour variability.

Several of the region's utilities have developed services to meet this need. For example, BPA's Storage and Shaping Service (S&S) and Network Wind Integration Service, were developed to convert variable amounts of wind energy into predictable blocks of energy for later delivery (S&S Service) or to manage the hour-to-hour variability of wind output on behalf of Requirements customers. Grant County PUD and PacifiCorp have offered similar services, and some wind developers have also offered products that mitigate the hour-to-hour variability of wind. Figure 7 depicts the shape of wind power output after it has been stored and shaped for redelivery into flat blocks of peak and off-peak energy.

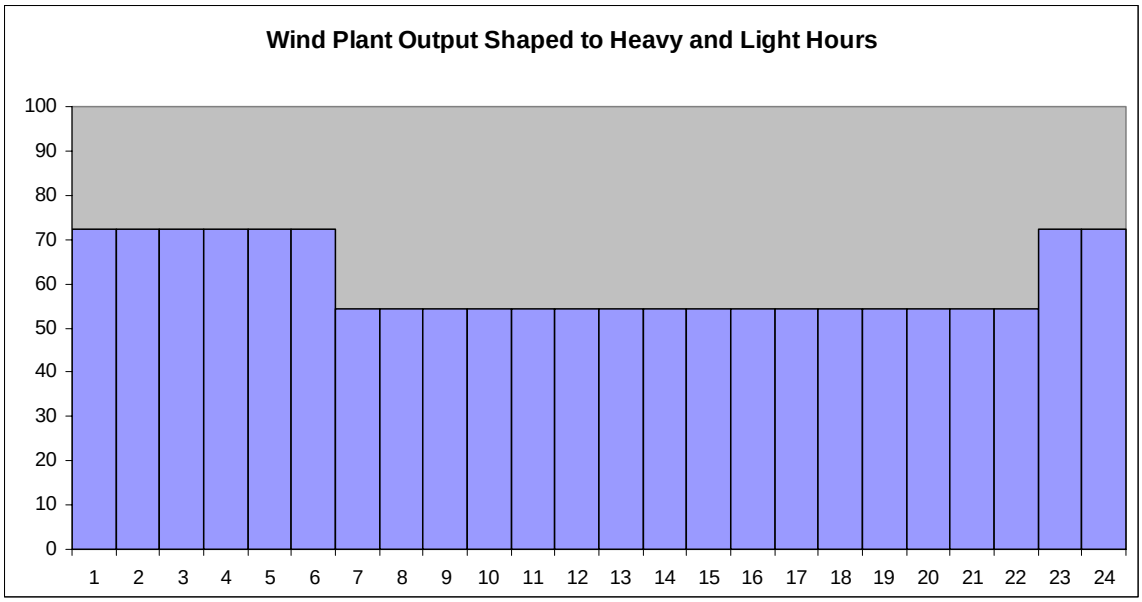

Figure 6: Wind output after purchasing a storage and shaping service

In the Northwest, hour-to-hour shaping services have generally been sold by the power (or "merchant") side of regional utilities. These commercial power products do not include the within-hour balancing services, which must be simultaneously purchased from a transmission provider. The market for shaping services is, at present, extremely illiquid. This is also true of the market for within-hour balancing services. We explore the root causes of this illiquidity, and potential ways to expand the market for these products in the Findings and Recommendations section.

Wind integration costs are driven primarily by the costs of securing and dispatching incremental operating reserves

The opportunity costs associated with the operational or marketing changes (required to carry incremental operating reserves) are the chief source of wind integration costs. There may also be additional wear and tear on hydro and other units, as well as efficiency losses resulting from the additional cycling. Together, these direct and opportunity costs are the underlying drivers of wind integration typically reported in utility wind integration studies. To the extent utilities lack sufficient flexibility to manage the hour-to-hour changes in wind output or differences between day-ahead schedules and actual hourly output, their studies will reflect additional costs associated with these impacts as well.

Generally, in such studies, utilities quantify the type and amount of additional balancing reserves required to integrate increasing amounts of wind into their systems. Actual reserve requirements vary on an hourly basis as a function of the size and makeup of the utility's existing Control Area, the interactions between patterns of wind generation and loads, the amount of geographical diversification of the wind projects, the current operating status of the wind projects in the Control Area (i.e. idled, at capacity, somewhere in between), and the risk tolerance of the

utility.[10] Reported amounts of incremental operating reserve requirements are typically based on averages at a certain level of wind penetration or by picking another point on the distribution (e.g. 95 percent) for such requirements at a specific level of wind penetration.

The fact that reserve requirements for wind integration vary on an hourly basis, does not mean that all utilities currently have the technology or processes in place to manage them on this time frame. As utilities develop more expertise with wind, they will develop better methods for more efficiently estimating and deploying hourly reserve requirements. If paired with a deeper pool of balancing resources, these will likely reduce wind integration costs on a per megawatt-hour basis.

Ultimately, the costs of within-hour wind integration and hour-to-hour shaping services are a function of the supply and demand of generating capacity, and the value of competing uses for system flexibility. Basic economics tells us that extending the supply of system flexibility will help keep wind integration costs as low as possible. For environmental reasons, it makes sense to take steps to extend the flexibility of our clean, renewable hydro resources for as long as possible.

Today, the Northwest sources most of its within-hour balancing capability from hydroelectric resources. Over time, the process of load growth and other uses may reduce the supply of available hydro flexibility. At that point, we will need to turn to other sources of regulation and load following capability.

As discussed in the Findings and Recommendations section, below, there are a number of individually small, but collectively significant steps we can take to stretch existing system flexibility as far as possible. These include improved wind forecasting and sharing regulating reserves. At the same time, we can hedge against the potential loss of hydro flexibility by ensuring that the next generation of conventional capacity resources has sufficient ramping flexibility to help manage the variability of wind. We can also begin to explore other sources of system flexibility that may combine cost-effectiveness and a low environmental footprint. For the foreseeable future, however, the costs of wind integration are probably capped at the cost of procuring regulation and load following capability from new gas turbines.

Based on initial findings from new Northwest studies and others around the country, the demand for incremental operating reserves is strongly influenced by three variables: (1) the size of the Control Area from which such services are procured; (2) the geographic diversity of wind sites and resultant generation patterns; and, (3) the ability to draw from a truly liquid market of regulation and shaping products. These initial conclusions emphasize the importance of the cooperative strategies outlined in Section IV. B.

The importance creating a geographically diverse, low cost wind fleet

Geographically diversifying wind projects can reduce total wind fleet variability and uncertainty as well as the incidence of large ramping events. Geographical diversification can also improve aggregate forecast accuracy. Lower variability and uncertainty translates directly into a lower

[10] Risk tolerance involves a number of issues including the possibility of violating NERC and WECC reliability criteria, which may carry significant monetary sanctions after June 2007.

trajectory for wind integration costs on a per-MWh of wind basis. The benefits of geographical diversification have been well documented in many wind integration studies, including the recently released Minnesota wind integration study. In Germany, system operators indicate that they have experienced limited amounts of additional reserve requirements under most conditions in part because their wind fleet is spread across large expanses of the country. Avista's 2007 wind integration study preliminarily confirms this relationship for the Northwest.

Figure 7: Wind Development in John Day (Lower Columbia) region

The Northwest currently is facing a shortage of firm transmission capacity in many of the region's windiest areas, including Eastern Washington, Oregon and Montana. Although this is a common issue faced by many regional utilities, it is of particular relevance to BPA, because more than 3,000 MW of wind development is being concentrated in a small, geographical area in the Lower Columbia Region. This high concentration of wind projects may increase the incidence of large ramping events, placing higher demands on hydro flexibility and other sources of balancing capability.

New transmission lines and new transmission products will be needed to leverage the benefits of a geographically diverse wind fleet. BPA and others are addressing this issue and seeking ways to provide additional transmission access to other windy regions in a least-cost fashion – while recognizing the limitations on BPA's ability to finance new lines. Other regional utilities and developers will play an important role in this process.

Because wind project output typically averages one-third of a project's generating capacity, two-thirds of the energy carrying capability of the project's transmission capacity goes unutilized. The *per unit* costs of transmission for the wind project can be very high relative to other generating resources with higher capacity factors.

When a new piece of transmission line is built specifically for the purpose of integrating new wind projects, the per-unit costs of such a line can be very high. However, in building transmission to the windy regions of Eastern Oregon and Washington, for example, there may be collateral reliability and commercial benefits to the grid as a whole. Moreover, if we can access wind sites with higher capacity factors, this will translate directly into lower busbar costs for wind. This is a very important point: ***a one percent increase in capacity factor can reduce busbar costs by $2.50/MWh.***

Given that the regulatory and policy environment is likely to continue driving the demand for wind energy, it may be most economically efficient to develop those wind energy resources that have the highest capacity factors and the best correlations with our seasonal and daily patterns of load. ***If new transmission lines open up access to wind resources with considerably higher capacity factors, the savings in busbar and balancing costs may more than compensate for the incremental transmission costs.*** Regional efforts are underway to create new transmission products that may help limit the total amount of new transmission needed to develop a geographically diverse wind fleet. More liquid secondary markets for transmission service would also help wind developers remarket transmission rights in excess of their hourly requirements.

More broadly, given that the Northwest will continue to develop other forms of dispatchable supply and demand-side resources to meet incremental load growth, long-term transmission planning for wind will need to be coordinated with transmission planning for other resources. In the process, we may find significant overlap in the transmission expansion needs for new wind projects and new sources of dispatchable capacity.

Extreme ramping events are infrequent but must be managed in order to maintain system reliability

Even in a relatively high wind penetration environment, the impacts of wind on the system will be quite modest during most hours of the year. Although geographical diversification and other strategies to reduce wind fleet variability will reduce the frequency and magnitude of ramping events, there will likely be times when large wind ramping events will coincide with periods of limited system flexibility. In the Northwest, the hydro system typically becomes constrained during peak runoff season when the system is operating at or close to peak capacity in order to pass large volumes of water without creating harmful levels of spill. During the night's graveyard hours, hydro resources are typically operated close to minimum hydraulic requirements in order to conserve water for peak loads, and there's little ability to further reduce their electrical output.

Under these conditions, large, unexpected increases in wind generation need to be managed in other ways: by marketing the wind power on short notice (which may be very difficult given our current market structure), backing down other generation such as gas or coal plants, energizing pump storage units, activating dispatchable loads such as irrigation pumps, spilling hydroelectric energy at non-environmentally constrained projects, or reducing the output of the wind projects.

Under certain circumstances, the most economical option for obtaining system balance may be to reduce the output, or “feather”, a portion of the wind fleet. The Federal Energy Regulatory Commission (FERC) now requires that wind turbines have the technological capability to participate in system balancing mechanisms.

Although the specific economic and operational framework for implementing these controls (as well as the probability of having to use them) has yet to be worked out, regional utilities and the wind community are working together to secure this capability for the Northwest in the most economically efficient manner possible. In fact, some utilities have already included such provisions in their power purchase agreements with wind developers.

FINDINGS AND RECOMMENDATIONS

This section provides a detailed discussion of our major findings and recommendations in response to the major questions embedded in the work plan.

I. Does the Pacific Northwest have the physical capability to integrate up to 6,000 MW of wind? What are the estimated costs of integrating this amount of wind energy?

A. Operational Integration Capability and Initial Study Results

This Section is still under development as part of a peer review process. Given the importance of these numbers and the large amount of new information that is just now coming out of these studies, we believe it is essential that we complete the peer review process over the next 2-3 weeks before formally releasing the numbers. Based on initial results, we do not anticipate that the numbers will change any of the other major conclusions of the document

Section Outline

Analytical approach to modeling incremental operating reserve requirements
Summary of Avista Study Methodology and Results
Summary of Idaho Power Study Methodology and Results
Summary of BPA Study Methodology and Results
Summary of earlier studies by Puget Sound Energy and PacifiCorp
Comparative Cost Estimates at various levels of wind penetration
Cost Comparisons with Other Wind Integration Studies
Conclusions
Recommended next steps for refining analysis

B. Improved wind resource data is needed

Improved wind resource data is needed to confirm integration capability, and to assess the capacity value of wind, the benefits of innovative transmission products and the benefits of geographic diversity.

At the outset of this project, it was clear that the Northwest does not possess sufficient wind data to produce a highly realistic representation of the operating characteristics of a 6,000 MW wind fleet. Although there is now more than 1,200 MW of wind in the Northwest, it is statistically invalid to simply scale up the output of a smaller number of wind projects to represent a larger aggregation of projects. That's because it will not adequately capture the dynamics of spatial diversification and smoothing that may materialize with a larger wind fleet. In addition, a high-quality wind data set requires time-synchronized wind and load data to capture meteorological forces that impact wind and loads simultaneously.

Based on their experience with other major wind integration studies, several members of the Technical Work Group expressed concerns that this data limitation could compromise the results of its initial wind integration cost assessments, as well as its ability to rigorously assess the benefits of cooperative operational strategies and transmission expansion alternatives in 2007. Other members disagreed, explaining that data sets will never be perfect, and that existing data would go a long ways toward our assessment goals.

To address the data concerns, we recommend the development of a high-quality wind resource assessment for the Pacific Northwest.

Appendix 1 contains a thoroughly vetted set of technical requirements for such an assessment that can be easily adapted to a Request for Proposals Format in early 2007. An estimate of cost and timeframe for completion is also included. Members of the Technical Work Group generally agreed that there is a strong business case to be made for developing this data. This is based on the value of such a data set in further evaluating the capacity value of wind, conducting transmission planning, evaluating the probabilities of large wind ramping events, and exploring the benefits of cooperative operational strategies. We therefore recommend moving forward with this data acquisition process as quickly as possible. We recommend that the Northwest Power Pool, with its considerable experience in data aggregation and management, serve as the lead organization and eventual host for the data.

Develop a Northwest wind resource data set*: In coordination with the Northwest Power Pool, BPA and Northwest utilities should contract for the development of a synthetic multiyear, 10-minute, high-resolution chronological regional wind resource data set. This assessment should be based on historical, time synchronized weather and load data, and it should be conducted at a sufficient level of detail to be effective in modeling the impacts of geographical diversification, the capacity value of wind, the coincident peak of different wind resource areas, and the probabilities of large wind ramping events. This recommendation is a high priority and should be complete by Q1 2008.*

Given the rapid rate of growth of wind in the Northwest, the lack of high-quality wind data should not prevent progress in our efforts to develop initial estimates of the costs of wind integration, and our work in laying the foundation for the development of cost recovery

mechanisms in 2007-2008. Instead, we chose to work with currently available data, consult with wind data and forecasting specialists to ensure that any resulting statistical shortcomings were mitigated to the extent possible, and note potential shortcomings. In addition, the recent Idaho Power and Avista studies benefited from more robust wind data developed in conjunction with EnerNex.

There is a considerable amount of procedural and methodological work on recommended action items that can be conducted in early 2007. We can update results when better data becomes available. By fostering open dialogue and a comprehensive peer review of current and future study results, we feel confident that we can continue making progress on our work while taking steps to secure higher quality data and quantify its impacts, if any, on our results. We therefore offer the following formal recommendation:

C. The sustained peaking capacity value of wind should be assessed

In December 2006, the Council, voted to adopt a pilot capacity standard developed by the Northwest Regional Resource Adequacy Forum. The pilot capacity standard, together with an energy standard and an adequacy warning implementation plan comprise a comprehensive resource adequacy standard for the Northwest. The capacity standard will be used to assess the adequacy of the power supply to provide electricity over peak hours throughout the year. The standard includes a metric and targets. The metric is surplus sustained peaking capacity (in percent), and the winter and summer targets are 25 percent and 19 percent, respectively. The targets include three components: an operating reserve, an adverse temperature reserve, and a planning adjustment reserve. These targets yield a loss of load probability (LOLP) of five percent.

Winter and summer peak electrical loads in the Northwest tend to result from regionwide extreme cooling and heating events. Despite strong regional contrasts in climate and weather, extreme departures from norms tend to be consistent and well-correlated[11] through much of the region. Extreme heating and cooling events in the Pacific Northwest are driven by regionwide, high-pressure systems accompanied by stagnant air. During these events, which may last for several days, wind projects will make only a limited contribution to meeting peak loads. For example, during the peak hot weather event of July 24, 2006, the regional wind fleet operated at 5 to 10 percent of nameplate capacity. Likewise, during the extreme cooling event on November 27, 2006, the wind resources of BPA and NorthWestern Energy operated at 3 percent of nameplate capacity.

This suggests that Northwest wind projects provide low, single peak-hour capacity value, at least in their current geographic diversification. However, because of the short-term storage and shaping capability of the Northwest hydroelectric system, the single-hour or even daily-peak period capability of a resource is not representative for system reliability purposes. Rather, the average generating capability of a resource over a period of several days (sustained peaking capacity) determines the capacity value of a resource for meeting peak loads.

The sustained peaking capacity value of a resource, for purposes of system reliability, is based on a 10-hour peak load period over five sequential days (the 50-hour sustained peaking capacity). This definition

[11] Climate Impacts Group (http://www.cses.washington.edu/cig/pnwc/pnwc.shtml).

should increase the peaking period capacity value of wind because the expected average output of a wind project will be greater for the sustained peaking period than for a single-hour or daily-peak period.

While the capacity value of wind power was of little concern when wind comprised a small fraction of system capacity, the increasing penetration of wind power has heightened the importance of correctly assessing its capacity value. By 2009, wind is expected to comprise more than 5 percent of installed capacity and likely will continue to grow.

In recognition of this, Action GEN-8 of the Fifth Power Plan includes a call to "improve the understanding of the capacity value of wind." The Resource Adequacy Forum has assigned a provisional, 15 percent sustained capacity value to wind for evaluating the performance of the regional power system, with respect to the pilot capacity targets. Little data or analysis underlies the provisional value, and the Adequacy Forum has called for further assessment. Based on data from recent peak load events, the Technical Work Group believes that the 15 percent capacity value for wind may be too high. It recommends the value be formally assessed when sufficient data is available.

Therefore, we urge a formal assessment of the sustained peaking capacity value of wind power in the Northwest. This work is expected to commence with adoption of a method for assessing the sustained peaking capacity value of wind power in meeting Northwest system reliability targets. This will be followed by application of the method to estimate the sustained peaking capacity value of wind for the current year, as well as three and five years into the future, consistent with the adequacy warning implementation plan adopted by the Council.

The three and five-year cases should consider the possible effects of increasing penetration, greater geographic diversity and other possibly significant factors. Because the penetration of wind power is not likely to exceed 5 percent before the end of 2008, we regard completion of this action to be of moderate priority with a target date of year-end 2008. This will allow the assessment to draw upon the improved wind resource data called I.B. Because of the expected sensitivity of the capacity value to penetration, diversity and possibly other factors, this assessment may need to be revisited periodically as the role of wind in the Northwest system continues to grow. We recommend that the lead organization for accomplishment of this action be the Northwest Regional Resource Adequacy Forum with the technical assistance of the proposed Northwest Renewable Integration Forum (SectionV.A).

II. What are the short-term and longer-term transmission requirements for developing 6,000 MW of wind?

Sufficient long-term firm transmission capacity appears to be available at the Big Eddy (The Dalles), John Day and Slatt main grid interconnection points to accommodate the expected demand for new wind capacity forecasted through 2009. However, long-term firm transmission capacity is not adequate to service current wind project interconnection requests on BPA's system, much less to serve the 6,000 MW, or more of expected longer-term regional wind development[12]. Furthermore, currently available long-term firm transmission capacity may be

[12] The apparent inconsistency – between the availability of transmission to meet forecast demand for new wind capacity and wind project interconnection requests – comes about because the former is a demand figure and the second is potential supply. Potential supply typically will exceed demand during a bullish period of development such as the one we [12] are experiencing for wind power. For the Wind Integration Action Plan, we forecast a near-term (2007 through 2009), regionwide expected demand for 1200 MW of wind power, with high and low bounds of

inadequate to support the near-term (2009), high-case, wind capacity demand forecast for this study.

The lack of incremental, long-term firm transmission capacity on the regional transmission system has been a persistent problem over the past few years, and it is becoming particularly acute in the wind resource areas east of the Columbia River Gorge. There hundreds of megawatts of wind capacity are under construction, and thousands of megawatts of new wind capacity are proposed. With creativity and regulatory support, the development of 6,000 MW, or more of wind can be accomplished without a one-to-one expansion of transmission and wind capacity. Achieving this result will require a combination of transmission expansion, new commercial practices, and new regulatory policies to facilitate the efficient delivery of wind power to load.

A. Development of the proposed West of McNary transmission reinforcement should proceed as quickly as possible

In recent years, one particular transmission path – McNary to John Day – has been the focus of considerable attention with respect to wind power development. Within this path are two constrained flowgates: West of Slatt and West of McNary (Figure IV.1). To the east of the West of Slatt's flowgate lies a region with considerable wind potential – up to 3,400 MW according to estimates prepared for this study.

Concerns about the potential for congestion across the McNary to John Day path led BPA, in 2004, to offer an "open season" to secure financial commitments for a proposed McNary-John Day 500 kV transmission line. This expansion was viewed as a response to market demand (i.e., transmission service requests for new generation), versus system reliability concerns. BPA, then and currently constrained by its borrowing authority limitations, therefore looked to generating project developers as the primary source of financing for the upgrade.

This model protects existing transmission customers from risks due to generation project termination. However, the open season failed to secure sufficient financing commitments from developers to build the line. Although subsequent revisions to BPA's ATC[13] methodology freed up several hundred megawatts of additional long-term transmission capacity, since 2005 BPA has been unable to offer any additional firm transmission capacity on this path. As a result, wind developers have focused on the area to the west, where Available Transfer Capability (ATC) is more readily available.

2,200 and 1,100 MW, respectively. Regionwide, interconnection queue requests for unconstructed capacity currently total approximately ____ MW.

[13] Available Transfer Capability. Transmission capacity available for long-term sale as defined by the Open Access Transmission Tariff.

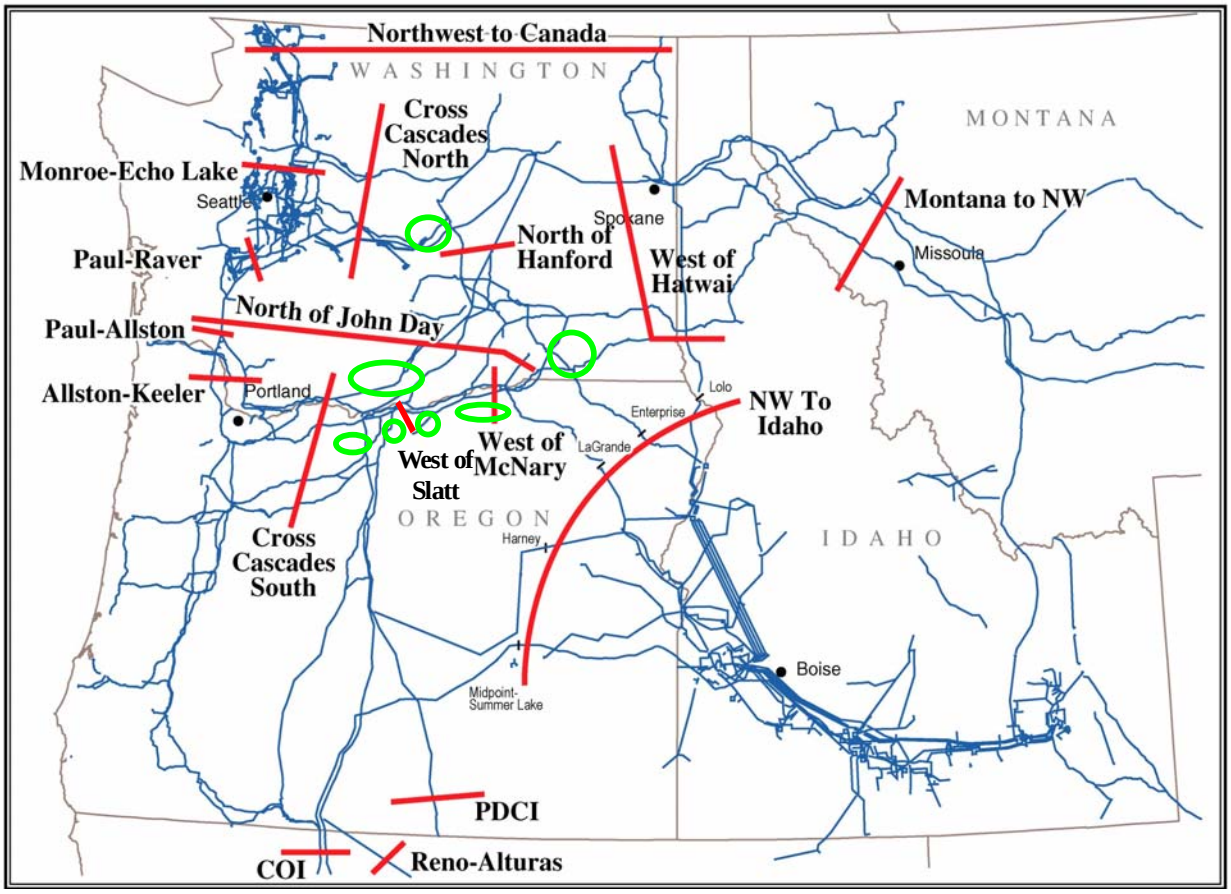

Figure IV.1: Major transmission path constraints

Recently, BPA has further defined the reinforcements needed to increase West of McNary transfer capacity. As described in Appendix 4, upgrades would now extend further west, to The Big Eddy substation near The Dalles, and would also include interconnections to the north and south. The reconfigured project could be constructed in two phases, building only as needed.

There are numerous potential benefits to building new transmission across the West of McNary path. An upgrade to the line would:

1. Open up access to potentially higher capacity factor wind resources in Eastern Oregon and Washington.
2. Allow integration of additional projects where the local grid is so constrained that new projects cannot be hooked up even if they are not requesting firm transmission.
3. Provide greater geographical diversification in the region's wind fleet. This might reduce the probability of extreme ramping events, improve aggregate wind forecasting accuracy and reduce the need for balancing reserves producing direct savings in wind integration costs.
4. Add additional margin to the transmission system as a whole. This will facilitate the development of redispatch markets and potentially make it more tenable to offer

conditional firm transmission products to the next generation of resources once any additional firm transmission capacity created by the line upgrade has been consumed by new projects.

5. Demonstrate that the region could address transmission issues that long have been the subject of much talk and little action. A successful planning and financing process for the West of McNary Day upgrades could serve as a prototype for other, largely market-driven reinforcements and expansions of the transmission system, including trunk lines constructed to access prime wind and other renewable energy resource areas.

Because of the above benefits, and because existing long-term firm transmission capacity may be inadequate to support plausibly higher levels of near and long-term wind capacity development, the Transmission Subcommittee of the Technical Work Group recommends that the development of the proposed West of McNary reinforcements be aggressively pursued.

Expand the West of McNary Transmission Path: *BPA should proceed in a timely manner by finalizing the plan of service, and reviewing the plan and business case for the proposed West of McNary reinforcement with the region through the Infrastructure Technical Review Committee in 2007. After securing necessary commitments, BPA should commence with environmental analysis for the revised scope of the West of McNary project.*

B. Transmission products such as conditional firm service could improve the efficiency of using the transmission system

While there are compelling reasons for moving forward with the West of McNary reinforcements, the project may take four years to complete. Meanwhile, no long-term firm transmission capacity is available to serve additional project interconnection requests. A combination of firm and non-firm transmission, or new products such as conditional firm service, can be coupled with generation redispatch, to use existing transmission as efficiently as possible.

Conditional firm service was conceived to take advantage of the fact that during most hours of the year, there is sufficient Operational Transfer Capability (OTC) across the transmission system, including the West of McNary path. The number of hours of congestion, given current patterns of load and generation, are quite small. The transmission system actually is underutilized during many of the hours of the year, though the hours of congestion will increase as more generation is built.

Under conditional firm service, a transmission provider would guarantee long-term transmission service for a certain portion of the year when there was sufficient transfer capability in the system. This would be combined with a modified, non-firm transmission agreement for those portions of the year when there is a higher probability that the transmission lines would be loaded to capacity. Wind developers have agreed that, absent long-term firm service, conditional firm service, with potentially few hours of interruption and favorable conditions, would suffice in securing third-party financing for projects. No utilities have yet offered conditional firm service, but it remains a promising product if technical and equity issues can be sorted out.

Complementary mechanisms to help alleviate congestion on the transmission system are also under consideration. Generation redispatch is one of these. Redispatch would shift generation from one part of the system to another, to reduce loading on congested transmission lines based upon agreements between willing parties. This would effectively increase ATC. This summer, BPA will be running a pilot reliability redispatch project that may ultimately be expanded to proactively manage congestion on the system and enable products like conditional firm service.

Of course, the devil is in the details, and designing commercial practices that use existing capacity (to support new resources on a not-quite-all-the-time firm basis) will also require regulatory policies that support cost recovery for utilities purchasing the long-term output of wind projects without long-term firm transmission.

The Technical Work Group concluded that there is an immediate need to concurrently pursue "soft" solutions – such as the development of conditional firm service products and redispatch capability – in parallel with a build out of the West of McNary project. Meanwhile the region will gain experience in applying tools to more efficiently use transmission before the next phase of expansion is contemplated.

While the traditional utility paradigm requires firm transmission for the full output of a generating plant, this is not efficient for an intermittent resource. A wind plant with 33% capacity factor essentially triples the cost of transmission. The Region should develop a transmission expansion model that uses the tools above to determine a mix of firm, nonfirm and/or conditional firm to deliver wind efficiently. This will ensure that transmission is expanded only when appropriate.

Pilot conditional firm service product: *BPA should work with project developers, customers and other interested and affected parties to develop and test a pilot conditional firm transmission product. The initial objective is to use existing West of McNary transmission as effectively as possible. The product should also serve as a prototype for similar service offers on other possible paths. For the product to be viable, the curtailment risk associated with the product must be sufficiently attractive to allow third party, wind project financing to be obtained. Also, it should limit increased curtailment exposure for existing firm transmission customers to acceptable levels. This is a high priority. A decision on whether to offer pilot conditional firm service should be made by the end of 2007.*

Pilot generation redispatch program: *BPA should complete its reliability redispatch pilot program and begin the development of a voluntary redispatch program using Federal and non-Federal generation, to increase ATC on the West of McNary path. This program may operate independently or in conjunction with the pilot conditional firm service called for above. As with that service, the generation redispatch program should serve as a prototype for similar service offers on other possible paths, and not interfere with prior firm service commitments or impair system reliability. This is a high priority. A pilot program should be operating in 2008.*

The Region should develop a transmission expansion model that uses the tools above to determine an efficient mix of firm, nonfirm and/or conditional firm to deliver wind efficiently. This work could proceed under the auspices of a regional transmission planning organization such as Columbia Grid and Northern Tier Transmission Group.

C. Development of a model for financing and recovering the costs of transmission serving market needs is needed to maximize the value of wind power and other location-dependent renewable resources

Prerequisite to constructing new transmission projects that provide access to wind rich areas is the development of a financing mechanism for projects, like the West of McNary reinforcements that are largely market-driven. The financing paradigm must address the awkward Catch-22 confronting many wind project developers regarding transmission: Developers cannot make financial contributions to a new transmission line unless they have security in the form of a power purchase agreement, yet they typically cannot secure a power purchase agreement without a long-term transmission service agreement.

Other states, such as California and Texas, are actively working with state regulators and FERC to find a way out of this conundrum, and to develop policies and cost-recovery mechanisms which do not rely as heavily on guarantees from resource developers, yet enable new transmission in support of their aggressive renewable energy objectives. Resolving the financing issue will become increasingly important as the demand for renewable resources drives the need to construct trunk transmission lines connecting rich resource areas to the main transmission grid. Some of the lessons learned from developing a model for projects like the West of McNary reinforcements may be useful, but other approaches, such as joint ownership, capacity ownership, or supporting efforts of independent developers need to be evaluated. For trunk line projects, identifying financing mechanisms that provide single-rate (non-pancaked) service over long distances is particularly important.

When the proposed projects are in the heart of the Bonneville system, financing solutions must also meet federal requirements and satisfy the Bonneville's operational concerns, which may make proposals for joint ownership by regional utilities less attractive. In that situation, nonetheless, efforts should be made to encourage participation of regional transmission providers in joint planning and support of projects. New approaches, whereby other transmission providers could help finance projects and obtain capacity for their transmission customers resulting from Bonneville expansion efforts, should be explored and any statutory or regulatory impediments identified and addressed.

In addition, certain utility regulatory policies discourage needed upgrades of the transmission grid. In recent years FERC has enacted incentives for transmission expansion by investor-owned utilities subject to its Section 205 rate regulation. However, because these FERC policies are not aligned with state regulatory policies on utility cost recovery, there is no assurance that an investor-owned utility's shareholders would benefit from the FERC incentives.

In the Northwest, revenues from wholesale transmission are typically treated as an offset to the state-determined rate base and operating expenses. Therefore, even if FERC allows an investor-owned utility to collect incentives on new transmission, absent state policies to allow the utility to retain the incentives, the incentives would be passed through to ratepayers. While such a system might encourage ratepayers to support transmission expansion, it provides no additional incentive to utilities to invest their capital in transmission expansion. Unless FERC and the states

coordinate policies to provide shareholder incentive, the incentives will not accomplish their intended goal.

Paradigm for financing the West of McNary project: *BPA should work with developers, customers and other interested and affected parties to develop an approach for financing and recovering the costs of the proposed West of McNary transmission reinforcement project. Though priority should be given to West of McNary project needs, effort should be made to create a model that could be adapted to other transmission projects. The review should include exploration of new approaches to participation other transmission providers in BPA projects and identification of any statutory or regulatory hurdles to their participation. BPA has begun a regional discussion on the development of this policy. This is a high priority and should be completed by the end of 2007.*

Review and amend if necessary regulatory policies governing recovery of transmission costs: *Utilities and the state regulatory commissions should review transmission cost recovery policies to ensure that they are consistent with the transmission products and transmission expansion financing models called for above and structured to provide adequate incentives to investor-owned utilities participating in transmission expansion projects. Policies should be amended, if necessary for consistency. The review should include exploration of new approaches to participation in transmission projects and any changes in FERC policy that the utilities and state commissions might recommend. This action is of high priority and should be completed by the end of 2008.*

D. Reinforcement of transmission in the I-5 and Cross-Cascades corridors will be required to support additional generation serving west-side loads, including expected near-term wind power development

The transmission system south of Paul substation in the I-5 corridor (Figure IV.1, Paul - Allston flowgate) is today frequently congested during spring and summer. Though somewhat exacerbated by flow from wind development east of the Cascades, it becomes further constrained under all future generation development scenarios, including new and proposed generation in the I-5 corridor. A comprehensive plan for upgrading this path needs to be developed to provide for wind and other proposed resources. The impact to the Cross Cascades is more difficult to access. The need for additional Cross Cascades transmission historically has been driven by load growth, but it may be accelerated if dispatchable west-side resources are turned down in response to wind availability during peak load periods.

Conceptual plans for the I-5 Corridor and Cross Cascades transmission reinforcements are described in Appendix 4. Comprehensive planning studies, to determine the plan of service requirements in more detail remain, to be completed. These studies are being conducted in response to requests to relieve the transmission constraints. Of the two recommendations that follow, development of a plan of service for the I-5 corridor should be given priority.

Develop a Plan of Service for I-5 Corridor Reinforcement: *Bonneville in cooperation with Regional stakeholders should develop a plan of service for I-5 corridor reinforcement. The plan of service should identify future transmission system needs for the I-5 corridor by a combination of capacity planning and energy planning tools. These studies should identify preferred system upgrades, estimate the cost of system upgrades, identify the amount of commercially viable ATC for each system upgrade, and identify*

timing for implementing the preferred upgrades.

Develop a Plan of Service for Cross-Cascades Reinforcement: *Bonneville in cooperation with Regional stakeholders should develop a plan of service for Cross-Cascades reinforcement. The plan of service should identify future transmission system needs for the Cross-Cascades corridor by a combination of capacity planning and energy planning tools. These studies should identify preferred system upgrades, estimate the cost of system upgrades, identify the amount of commercially viable ATC for each system upgrade and identify timing for implementing the preferred upgrades.*

E. Additional transmission system upgrades may be desirable in the longer-term to channel new wind development to the most cost effective sites

Abundant, high-quality wind resource areas with compatible land uses lie to the east of the Rocky Mountains in Montana. Good, though remote, wind resource areas are found elsewhere in the region. Development of the wind resources of these areas largely has been precluded because of limited transmission capacity to load centers.

Planning is underway for the Montana - Alberta Tie Line (MATL) a privately funded 230kV merchant transmission interconnection between Great Falls, Montana and Lethbridge, Alberta[14] providing 300 MW of transfer capability. While potentially servicing several hundred megawatts of Montana wind power to serve Alberta loads, MATL would not increase transfer capacity to Oregon or Washington load centers.

The Rocky Mountain Area Transmission Study (RMATS) identified transmission projects that could provide significant economic benefit to the Rocky Mountain area. Among the RMAT proposals was strengthening the existing east-west Colstrip transmission line to provide capacity to transfer coal and wind energy from eastern Montana to Washington and Oregon load centers.

The 2005 Northwest Transmission Assessment Committee (NTAC) Montana–Northwest Study investigated the system additions required for a capacity increase of 750 MW from Colstrip to the Washington and Oregon Westside load areas. The RMATS and NTAC did not focus on the wind resources located in the North Central Montana area. The Technical Work Group has concluded that a targeted transmission study that addresses integrating potential wind resources from the various areas in Montana is needed.

These, and other promising Northwest wind resource areas, could provide greater geographical diversification in the region's wind fleet. This might reduce the probability of extreme ramping events, improve aggregate wind forecasting accuracy and reduce the need for balancing reserves producing direct savings in wind integration costs.

The following recommendations should be implemented to better understand the potential costs and benefits of extending transmission to service the wind resource areas of Montana and other promising, but isolated Northwest wind resource areas.

[14] www.matl.ca

Complete and expand assessments of the feasibility and costs of extending transmission to promising, but transmission-constrained Montana wind resource areas: These studies should include at least the following: (1) **C**omplete a study of historical path usage (both schedules and actual flow) to gain a better understanding of usable ATC on the various Montana to I-5 Corridor paths; (2) Identify potential transmission upgrades to integrate wind resources in the Great Falls area, estimate the cost of the upgrades, and the amount of commercially viable ATC for each upgrade; and (3) Complete the Colstrip Transmission System Upgrade Study

Assess the feasibility and costs of extending transmission to other promising, but transmission-constrained wind resource areas: These should include the Union County area of northeastern Oregon, the Dayton area of southeastern Washington, and the basin and range ridges of southeastern Oregon, northern Nevada and southern Idaho.

III. How will the costs of wind integration be recovered?

The within-hour variability of wind power located in a host utility's control area is managed by using other resources in the control area, even when the output from the wind capacity is sold to a utility in another control area. Under the current Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT), only the loads in the host utility's control area are charged for the cost of within-hour balancing for the resource as part of Regulation and Frequency Response Service charges. The current tariff was designed when resources in the control area only had to respond to meet within-hour variations of loads in the control area.

The billing determinants established by Northwest utilities for recovering Regulation and Frequency Response costs typically are based on energy consumption or demand; none allocate regulation or other within-hour balancing requirements based upon the individual loads variability. Large loads with significant within-hour variability add to control area balancing requirements, and the cost is spread among all loads under current rate designs.

Thermal resources generally do not add to the control area balancing requirements due to the technical characteristics of the generators themselves, but wind resources do add to balancing requirements. There is no statistical correlation between within-hour variations in load and within-hour variations in wind resource output.

As increasing amounts of wind capacity are interconnected to the host utility, the control area within-hour balancing requirements will increase. At some point, a threshold may reached where the current balancing cost allocation model of the OATT becomes too far removed from cost-causation and the host utility will have to make explicit choices about how to allocate the additional costs. The choices are to increase the charges that the host utility's loads pay under the current tariff, or develop a new tariff to implement rates that more closely aligned the charges with the contribution of loads and resources to the total control area balancing requirement.

There are diverse opinions about when the mismatch between cost causation and cost allocation becomes large enough to warrant developing a new tariff, and how that tariff should be designed. Given the multitude of control areas in the Northwest, there is no simple single answer to these questions. In addition, diverse policy perspectives exist about who should bear the costs

associated with balancing wind resources. . Nevertheless, this is particularly important when under current tariffs the costs for managing wind variability are borne by loads in the host control area while the wind energy is destined for consumers in multiple control areas.

Although it is technically feasible to statistically disaggregate the contribution of individual loads and resources to the total control area within-hour balancing requirements, implementing a customer-specific metric for billing purposes would be a challenge. There are no revenue-quality meters that can provide a verifiable quantity for billing purposes, so some statistical treatment of SCADA data will be required, whether the costs are allocated to broad customer classes or to individual customers.

We do not propose a specific tariff modification and billing determinant in this effort, but we do offer some suggestions for consideration regarding the development of balancing tariff and rates.

Cost-causation should be an important consideration for tariff design. Those that create the need for within-hour balancing requirements should bear a cost commensurate with their use of system resources. The more removed a tariff design is from customer-specific metrics for use of the system, the farther from cost-causation it becomes.

There should be a defensible basis for determining any additional within-hour balancing requirements resulting from wind resource interconnecting in a control area. This becomes especially important if the additional balancing requirement translates to increased rates for providing this service.

The ability to provide customers with verifiable billing for use of within-hour balancing capability is also an important consideration.

Balancing policy perspectives is critical. Because of the significant regional support for wind resource development, movement toward increasing the explicit costs incurred by wind generators via a balancing tariff that applies to wind generators will likely meet some opposition, unless accompanied by like efforts to improve the relationship between rate structures and cost causation. The threshold for demonstrating significant cost increases will be an important factor as specific utilities evaluate whether or not to develop tariffs that more closely align with cost-causation.

IV. How can we work together to help the region meet its wind energy potential at the lowest overall cost?

A. Create a Northwest Renewable Resource Integration Forum to facilitate implementation of the Wind Integration Action Plan

This report recommends that over the next several years, BPA, the Council, utilities and other regional organizations undertake a number of actions to ensure that expected near -term wind power development can be effectively integrated into the Northwest power system. They also need to maximize the economic and environmental value of longer-term wind development.

While certain recommendations can be undertaken independently by BPA or other organizations without the necessity of regional coordination, many of the recommendations will require the participation of multiple organizations to be accomplished. Some, such as the proposal for developing improved regional wind data, will also require joint funding. In several cases, cooperative efforts to implement the recommendations are currently underway under the auspices of the Technical Work Group.

The organizational model adopted for the first phase of work – a Policy Steering Committee and a Technical Work Group with specialist subcommittees – is ideal for implementing the cooperative recommendations of this report. The Northwest Resource Adequacy Forum, with a similar operational structure, has successfully and expeditiously developed regional reliability metrics and targets. For these reasons, we propose that this effort be renamed the Northwest Renewable Resource Integration Forum. This will reflect the regional focus on implementing the actions recommended in this report, as well as the expectation that many of the integration issues confronted by wind will be common to other renewable resources. It would continue with essentially the same structure and membership to achieve the following:

- Assemble the technical expertise, data, analytical and financial resources needed to accomplish the actions identified in this report.
- Ensure that the actions are completed in a timely manner.
- Provide regional oversight, review and publication of work products.
- Periodically review the scope, objectives, and priorities of the recommended actions to ensure that they remain current and pertinent.

The intensity of the first phase of this work was driven by the need to identify possible impediments to expected near-term wind development needing immediate resolution. While the pace relative to actions bearing on longer-term development might be slackened somewhat, actions bearing on expected near-term development remain a high priority because of the continued rapid rate of wind development.

Overall, we recommend that the actions described in this report be completed by the end of 2008. To support this recommendation, members of the Policy Steering Committee or their representatives should continue to meet semiannually and that the Technical Work Group should meet quarterly at minimum. Technical subgroups should meet as required to ensure timely completion of their tasks. A draft charter for the Forum, modeled on the charter of the Regional Technical Forum is attached.

While the recommendations of this report should essentially be complete by the end of 2008, the Forum might be extended at the recommendation of the Policy Steering Committee if it appears productive to do so at that time.

Establish a Northwest Renewable Resource Integration Forum: *We propose a continuation of the current Wind Integration Action Plan organization and process as the Northwest Renewable Resource Integration Forum for a period of two years. The Policy Steering Committee, meeting semi-annually or more often if needed, should continue to oversee the overall effort at the policy level. The Technical Work Group, meeting at least quarterly, would guide the technical activity. Task-oriented subcommittees*

reporting to the Technical Work Group would accomplish the recommended actions. Because of the need to continue work on actions underway, and to begin work immediately on high-priority actions, the Northwest Renewable Resource Integration Forum should be endorsed by the Policy Steering Committee and begin operating by Q2 2007.

B. Implement cooperative strategies to extend integration capability and minimize wind integration costs

The Northwest operates as 13 separate control areas, each responsible for balancing its own loads and resources. Several operational strategies consistent with the current Northwest market structure could be implemented through bilateral arrangements between pairs or groups of utilities.

ACE Diversity Interchange

For the past two years the Northwest Power Pool has been developing a framework for ACE Diversity Interchange (ADI). In November 2006, the British Columbia Transmission Corporation, Idaho Power Company, NorthWestern Energy and PacifiCorp signed a memorandum of understanding to develop an ACE Diversity Interchange (ADI) tool for use in managing electric control areas. According to documents developed by the participating utilities,

> "The essence of ADI is that through coordination among multiple control areas, the control needed to balance load, interchange, and generation can be relaxed when compared with isolated operations. Relaxed control can be achieved because of the sign diversity (some are net positive or over-generating relative to load and some are net negative or under-generating relative to load) among area control errors (ACE). As a result of ADI, participating control areas can reduce their respective regulation burdens in real time while gaining an improvement in NERC Control Performance Standard compliance. ADI is also expected to result in a reduction in generator control movements." [15]

If the benefits of ADI materialize as postulated in the agreement, then this will translate into lower costs of regulating reserves for the participating utilities. Although the incremental demand for regulating reserves from wind energy is quite small, ADI may take a small bite out of the incremental costs of wind integration. By identifying multiple strategies for minimizing costs such as ADI, each perhaps with modest savings, total cost savings may add up to material benefits for utility customers.

More important, we applaud the participating utilities for their spirit of cooperation and dedication to solving the technical issues associated with ACE Diversity Interchange. Their effort may lay the foundation for exploring other mechanisms to share control area balancing requirements. We also believe that future participation in this ACE Diversity initiative by other utilities may be of value and merits further analysis. We therefore offer the following recommendation:

Report on ACE Diversity Interchange Agreement: *By July 2007, participants in the emerging ACE Diversity Interchange Agreement between several Northwest utilities should provide the Northwest Wind*

[15] ACE Diversity Interchange, November 1, 2006, page 1. Prepared by BCTC, IPCO, NWE and PAC. We note that The Northwest Power Pool is also investigating the costs and benefits of ADI.

Integration Forum with a report on progress made in implementing the agreement. Where analysis indicates that the benefits of such an agreement significantly exceed the costs, other Northwest utilities should consider the merits of participating in the agreement.

Control area balancing products and wind integration services

With the growth of wind energy in the Northwest, there is increased demand for products and services designed to help individual utilities and control areas manage their within-hour wind balancing requirements. Products for control area balancing include Supplemental Automatic Generation Control (AGC) and Dynamic Scheduling. These products and their variants allow one utility to take on a portion of the within-hour balancing requirements for another utility's control area.

There also has emerged the demand for specific services designed to manage the hour-to-hour variability of wind. These include storage and shaping services developed and offered by PacifiCorp, BPA Grant County PUD, and a Network Wind Integration Service, which has been offered by BPA to its Requirements Customers. Other utilities have offered dynamic capacity products that have been used in wind energy integration.

There are several potential benefits and cost savings associated with an expanded bilateral or multilateral marketplace for these services. They include:

1) Allowing more control areas to integrate more wind, thus expanding the geographical diversity of the region's wind fleet.
2) Helping smaller utilities that lack sophisticated marketing and trading operations to purchase the output of wind projects.
3) Through dynamic scheduling, allow two or more utilities to exchange the balancing requirements for a portion of the wind in their different systems, in effect leveraging the geographical diversity of their respective projects into lower individual balancing requirements[16].
4) Leverage the daily and seasonal differences in system flexibility among the region's utilities and help further reduce the probability of having to limit wind generation output during periods of hydro constraints.

Unfortunately, the market for balancing services and wind integration services is extremely illiquid. NorthWestern Energy is a prime example: In an effort to purchase control area balancing reserves to manage the 135 MW Judith Gap wind project, NorthWestern has run several solicitation processes for balancing capability, and found a limited number of sellers. In 2005, BPA placed a moratorium on the sale of its wind integration services, and Grant County PUD currently is not offering its storage and shaping service. Few other utilities currently are offering additional wind shaping capability.

We have explored the root causes of the illiquidity in the market for flexibility products, and have identified several important barriers:

[16] This strategy would build on the concept of ACE Diversity Interchange by allowing utilities to share total within-hour balancing requirements.

1) The transmission costs associated with Supplemental AGC and Dynamic Scheduling can be very high. Firm transmission – sometimes in both directions – is required.
2) There is limited dynamic scheduling capability across the Northern and Southern Interties. This limits access to the within-hour balancing capability of resources in Canada and California. According to BPA, there are substantial technical barriers to expanding this capability and reliably managing the grid.
3) Responsibility for developing and offering flexibility products often lies with the merchant (marketing) functions of the utilities, which may not have the necessary product understanding, risk appetite or pricing capability to offer them.
4) Some utilities may be unwilling to sell flexibility from their systems because they are concerned they will need the flexibility for their own needs, such as meeting Renewable Portfolio Standard (RPS) requirements. In BPA's case, uncertainty about the outcome of the current Biological Opinion remand process and future resource adequacy requirements led to the moratorium on new sales of wind integration services.
5) Biological requirements and other periodic system constraints limit contract lengths and require some utilities to require call-back provisions on any marketed flexibility.
6) Utilities must typically sign 20-25 year purchase agreements for wind project output, yet regulatory cost recovery mechanisms do not support the use of short-term balancing mechanisms.
7) There is no formal market or standard product descriptions for these services.

The first step in expanding the market for a product or service is developing a standardized product description. Therefore, we have drafted generic product descriptions for Supplemental Automatic Generation Control and Dynamic Scheduling. We also have drafted a description of a generic wind storage service that might be of interest to certain parties. These product descriptions are attached as Appendix X.

However, there remains a substantial list of barriers to greater liquidity in the bilateral market for flexibility services. This topic requires rigorous follow-on analysis in 2007. Therefore, we offer the following recommendation:

Resolve market barriers to flexibility products: *The proposed Northwest Wind Integration Forum should systematically address the transmission, scheduling, product design, regulatory, contractual and cost-recovery barriers to greater liquidity in the market for flexibility products and services.*

Explore options for increasing dynamic scheduling capability across interties: *BPA should explore and report on the feasibility of expediting relief from dynamic scheduling limits on interties to other control areas.*

Resolve uncertainties surrounding cost and availability of BPA's Wind Integration Services: *BPA Power Services should work with its customers and other interested parties to clarify uncertainty about the future cost and availability of wind integration services for its Requirements Customers and to develop an issue paper on the requirements for using wind energy as Tier 2 resource.*

Explore the benefits of a Regional Wind Forecasting Network: Good wind forecasting is

essential to minimizing the costs of wind integration on a utility system. All utilities with wind in their portfolios will likely invest in state-of-the art wind forecasting systems. At the same time, there is an emerging understanding that there may be benefits of using information from multiple wind projects and wind monitoring stations to create better wind forecasts for the group of wind projects as a whole, in addition to individual wind projects. It is essential that such a network be consistent with the needs of system operators and developers. We therefore offer the following recommendation:

Evaluate the costs and benefits of developing a Regional Wind Forecasting Network: *The proposed Northwest Wind Integration Forum should evaluate the costs, benefits, level of utility interest and technical issues associated with developing a regional, wind forecasting network.*

C. Develop operational and economic framework for using wind project output to extend system balancing and transmission capability

Although our initial analysis indicates that the Northwest has the physical capability to manage the addition of 6,000 MW of wind, there will be periods of time when large, unexpected changes in wind output will coincide with limited system flexibility. The Wind Project Operators Committee was tasked with exploring how wind plant output might be controlled to assist in balancing the system during those times when system flexibility is limited. In addition, the group has begun addressing related questions including:

- What are appropriate criteria for control area operators to use when considering wind plant dispatch?

- What are the economic tradeoffs of wind plant dispatch, versus the dispatch of other generators and loads, control area cooperation, and/or acquisition of additional resource capability for within-hour balancing?

FERC now requires wind plants to have the capability for bi-directional communication with control area operators

Since the late 1990s, with the advent of large, grid-scale wind projects in the Northwest, interconnection agreements have allowed control area operators to trip breakers and electrically remove wind plants from the grid if they are degrading the reliability of the system. This effectively limits their output to zero.

During the development of a standardized Large Generator Interconnection Agreement (LGIA) by FERC, the wind industry put forward a Supervisory Control and Data Acquisition (SCADA) requirement. It was adopted by FERC in its Order 661 and applied to post-2005 wind projects. The full text of this requirement in Appendix G of the LGIA reads as follows:

> "The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed

wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area."

Appendix G is essentially an acknowledgement of the importance and potential value of having grid-scale wind projects that are able to participate in system balancing mechanisms. However, Appendix G does not provide specific requirements, details or guidance about how wind project operators should translate instructions from control area operators into changes in wind output. Nor does it say anything about the technological sophistication of the output controls. Rather, as long as the operator can demonstrate the capability to receive and respond quickly to control area instructions, the letter and the spirit of the provision are satisfied.

A new generation of wind control technology

Over the past few years, wind turbine manufacturers have begun developing more sophisticated technologies for wind turbine communication and control. Based on input from wind turbine manufacturers Vestas and General Electric (GE), the new generation of wind output controls includes the ability to:

1. Establish maximum output limits,
2. Limit ramp up rates to default ramp rates or emergency set rates, and
3. Effect a smooth ramp down when taking the plant off line.

The most sophisticated controls allow operators to control the output of either entire projects or individual turbines. These are promising features, with the potential to achieve wind output control in a more subtle, cost-effective manner than simply opening a breaker or curtailing total project output. However, they will come at additional cost and are not expected to be a standard feature of new Pacific Northwest wind projects for at least the next two years. Many of the turbines slated for installation in the near future already have been purchased and do not possess these advanced controls.

The Northwest's wind projects have a diverse array of communication and control capabilities.

To get a better sense of the communication and control capability of the Northwest wind fleet, a survey was conducted of wind project operators in the region. The survey revealed that the communication and control capability of Northwest wind projects spans the gamut: from no communication and control technology, all the way to the latest generation of sophisticated System Control and Data Acquisition (SCADA) and output controls. In the middle of the range, there are some plants with some ability to control output, but this is strictly through the curtailment of individual turbines within the plant. Those with the most sophisticated systems can actually dispatch their wind projects remotely, using communication capability with a server at the wind site to take action almost instantaneously. It appears as though most of the largest and most recently installed wind projects meet the communications criteria set out in Appendix G of the LGIA.

More work is required to determine the most cost-effective way to implement Appendix G of the LGIA.

The Northwest's utilities will vary in their needs with respect to this issue. BPA, facing a substantial

growth of wind in its control area over the next few years, is planning to conduct a formal series of workshops in 2007 to develop an economic and operational framework for implementing Appendix G. Since limitations on wind output will impact wind project economics[17], it is essential that the issue be assessed through a rigorous cost/benefit analysis. As emphasized by the Northwest wind community, we will need:

1. A greater understanding of the magnitude of the problem and the frequency with which wind project output might be limited. If the situation is very rare, taking a plant off line may be more cost effective than investing in the sophisticated control capability necessary to smoothly adjust ramp rates, particularly for existing plants with limited control capability. The Wind Resource Data discussed in Section I.B should be used to further refine this analysis.
2. The development of clear criteria for using wind plant dispatch, so that system operators will not become overly reliant on controlling the wind fleet for economic or reliability reasons.
3. A thorough examination of the cost effectiveness of alternative operational strategies such as those identified in Section IV.B. In general, the least-costly option will provide the most benefit to electricity customers.
4. A willingness to explore creative approaches to the issue, such as allowing wind projects to trade ramp rates with other generators. This might give wind plant owners and electricity customers a more cost-effective alternative to curtailment or ramp limitations imposed by a control area.
5. Acknowledgement that pre-2005 interconnection agreements do not require Appendix G capabilities and cannot be changed without consent of all parties, although the interconnecting utility does have the authority to control plant operation to meet reliability requirements (e.g. by disconnecting the plant).

We conclude with the following recommendation:

Cost-effective implementation of LGIA Appendix G: *In implementing Appendix G of FERC's Large Generator Interconnection Agreement governing communication and control requirements for wind turbines, BPA (and other interested utilities) should work with wind developers and other interested parties to achieve the provision's objectives in the most cost-effective manner possible.*

D. Work together as a region to preserve our valuable – and increasingly scarce – hydro system flexibility

The Pacific Northwest faces an important question: how can we put our minds together to search for win-win strategies to optimize system flexibility for *all* of our competing needs? This Action Plan has identified how several individual and cooperative strategies (shared forecasting, ACE diversity, wind output management) have the potential to help minimize the demand for power system flexibility to manage increasing amounts of wind power. At the same time, we need to coordinate our thinking around other influences on the flexibility of the system.

17 Wind projects receive the production tax credit (PTC) on the basis of total generation. Curtailments or ramp rate limitations will reduce total output, and hence total PTC revenues.

Optimize use of hydro system flexibility

We all have a vested interest in a healthy Columbia River ecosystem and clean air. To date, however, we have not been prepared to engage in a fully informed discussion about how to best provide hydro system services to fish, wind integration and other consumers of hydropower flexibility. In recognition of the potential for wind power integration to adversely impact fish operations, the Northwest Power and Conservation Council, in Action GEN-9 of its Fifth Power Plan, calls for an assessment of the effects of "shaping"[18] large amounts of wind power on other hydropower system operations. The purpose of the Council's recommendation is to ensure that the use of the hydropower system for integrating wind power does not adversely affect other hydropower system operations. While supporting accomplishment of Action GEN-9, we propose to go a step further. Acquiring better understanding of the interactions between competing uses of the hydropower system, creates the possibility of identifying "win-win" opportunities to improve the use of the flexibility of the system for fish, wind power and other uses. Also, as noted in Action GEN-9, better understanding of the interactions between uses of hydro system flexibility will lead to better understanding of the value of flexibility. This, in turn will inform the assessment of flexibility augmentation options discussed in Section IV.E.

Seek improvements to use of hydropower system flexibility without adversely affecting non-wind uses of the system: *The Northwest Power Planning Council, Bonneville and hydro system operators should assess the effects of wind power integration on other functions of the hydropower system as called for in Action GEN-9 of the Fifth Power Plan. The resulting better understanding of the interactions between the various uses of hydropower system flexibility and the value of that flexibility should be used to identify possible improvements to the use of the flexibility of the system for fish, wind power and other uses without adversely impacting non-wind uses of the system. Moderate priority. Complete in 2008.*

Optimizing Mid-C Hourly Coordination

Since the 1960s, the Northwest has operated its hydro resources under several regional coordination agreements. The operation of the Mid-C resources is governed by an hourly coordination agreement. Given that a good portion of the region's hydro flexibility is provided by this complex of dams, optimizing the operation of these resources will increase their economic value and combined flexibility. The Mid-C Hourly Coordination Agreement has not been without controversy. In recent years, parties have been working collaboratively to resolve some of the highly technical issues that have prevented the Mid-C complex from operating as efficiently as might be possible. We applaud these efforts and believe they need to be strengthened. Examination of other bilateral or multilateral resource sharing agreements may also lead to an expanded supply of flexibility services. We therefore offer the following recommendation:

Optimize Mid-C Hourly Coordination: *Parties to the Mid-C Hourly Coordination Agreement should continue their efforts to resolve outstanding technical and operational challenges and should identify specific strategies that could enhance total flexibility for wind integration and other purposes. Other bilateral or multilateral resource sharing agreements should be examined in a similar light.*

[18] The term "shaping", as used in the Fifth Plan, refers to the full array of integration services including regulation, load following and storage and shaping.

E. Begin the search for the next generation of flexibility resources, including generation, storage and demand-side technologies

Today, the Northwest derives most of its regulation and load following capability from hydroelectric resources. The zero-emission, responsive nature of hydro facilities make them ideal for this task. Over the next 20 years, load growth and other forces will exert greater pressure on the flexibility of our hydro resources.

To a certain degree, we are already building the next generation of regulating and load following resources in the form of new natural gas turbines to meet our peaking capacity requirements. These resources soon may begin playing a more important role in providing the type of operating reserves needed to manage wind variability. In fact, for the foreseeable future, the costs of wind integration are probably capped at the market value of procuring regulation and load following from a combustion turbine burning fixed-price nature gas. But there are other demand-side, storage and emerging technologies for providing system flexibility that may have a better environmental footprint as well as the ability to add additional value to wind energy or help minimize the costs of new transmission. It is reasonable to start exploring these options today, investing R&D dollars in promising emerging technologies, and looking for ways to deploy these technologies in a least-cost, environmentally sustainable fashion.

The Next Generation of Natural Gas Turbines

The first technology many people think of when considering the next generation of flexibility technologies is the natural gas combustion turbine. Indeed, gas turbines provide much of the system flexibility in regions that do not have substantial hydro resources. Given that wind is not expected to meet a substantial portion of Northwest capacity needs, and the difficulty inherent in siting new coal facilities, it is likely that gas turbines will also play a major role in the future of the Northwest. With a large wind portfolio, the objective will be to run these plants as seldom as possible.

Partly as a result of the growth of wind energy, gas turbine manufacturers have begun developing a new generation of turbines that can provide both peaking capacity and balancing flexibility without significant degradation in operating efficiency. However, the cost of balancing reserves from this next generation of gas plants is likely to exceed that from hydro resources. This is primarily because gas plants must be operated at the mid-point of their ranges in order to provide bi-directional flexibility to the system. Also, they must burn natural gas, and under certain circumstances, be run when market prices are lower than variable operating costs.

General Electric, has recently introduced the intercooled LMS-100, the first of a new generation of very flexible turbines. While the capital costs are greater, the full load and turn-down efficiency of these machines is better than the current generation of simple cycle turbines, especially when operated at mid-point ranges necessary to sustain bi-directional flexibility. Their applicability to the Northwest may be limited until the point at which the supply of incremental hydro system flexibility appears to be small[19].

[19] Over time, the market *price* of flexibility may more closely approximate the marginal *cost* of flexibility from new gas resources before they are actually physically needed, yet the region may – for environmental reasons – prefer to consume its hydro flexibility before turning to fossil-fuel based (or other) alternatives.

On the other hand, facing a future with much more wind, utilities may choose to spend a bit more for this technology to secure the option on future flexibility given the uncertainties about the long-term availability and cost of hydro flexibility. Over time, we should expect greater technological evolution – and potential cost reductions – from new gas technologies. They will, however, always be a source of fossil fuel emissions. Environmental concerns may push us more actively towards the search for lower emission forms of flexibility.

Rethinking the operations of our combined-cycle gas turbines

Given the variety of services that simple-cycle GTs can provide (regulation, load following, peak period capacity and energy, spinning and non-spinning reserves, synchronous condenser service, poor water year hydro firming) existing and new, combined-cycle gas-fired turbines (CCCTs) might assist in meeting future flexibility requirements. Retrofitted with automatic generation control devices, CCCTs have the potential to provide bi-directional flexibility at modest cost. Because of their ability to capture waste heat from the gas turbine cycle, CCCT plants can potentially be backed down to provide reserves without significant heat rate penalties associated with simple-cycle gas-fired turbines.

Pumped storage and compressed air technologies

Pumped storage has many appealing characteristics for a system with high wind penetration. It can provide a full range of ancillary services, such as regulation and load following. It can provide a source of load during off-peak hours, shape wind energy into more valuable peak hours, and help manage grid congestion when transmission lines get heavily loaded.

Although pumped storage has high capital and operating costs that are difficult to recover given price patterns in the Northwest, wind storage during off-peak hours could help compensate for the limitations on hydro system flexibility at night. Also, it can add additional capacity and economic value to wind resources. There are many pumped storage facilities in operation around the country, including the 250-MW facility at Grand Coulee Dam. Compressed air storage technology is less commercially advanced, but should be able to provide the same basic services as pumped hydro storage.

California's Lake Elsinore pumped hydro storage facility: California is presently considering a new pumped storage facility at Lake Elsinore in the southern part of the Los Angeles basin. The project has an estimated price tag of $1 to $1.3 billion for 500 MW of capacity, and it is stirring lively debate about its economic merits. The facility, which would pump water into a large reservoir behind a 180-foot high dam in the Cleveland National Forest, is being proposed as a source of off-peak storage and operating reserves for the state's rapidly growing fleet of wind and solar projects. Mike Florio, a regulatory lawyer and consumer advocate with the Utility Reform Network, was quoted earlier in 2006 describing the project's sizeable price tag as reasonable and "fairly realistic."[20] The California ISO is squarely behind the project so it appears to have some chance of proceeding. If so, it will provide a valuable test case and some useful lessons about cost-effectiveness along the way. The operating economics of this project will be particularly interesting, including losses associated with the pumping process.

[20] *The Californian* (North County Times), March 8, 2006.

Iowa Stored Energy Plant: The Iowa Stored Energy Project, with potential financial backing from the Iowa Public Power Agency, is a proposed compressed air facility designed to store off-peak wind generation for later delivery during peak periods. The facility would compress air in a cavern formally used for natural gas storage. The facility would use off-peak electricity to power a motor/generator that drives compressors to force air into an underground storage reservoir. During peak load periods, the compressed air would be returned to the surface, heated by natural gas in combustors and run through high-pressure and low-pressure expanders to power a motor/generator to produce electricity. Developed specifically to store the energy of wind projects, the facility has a current cost estimate of $160 million for a 200 MW capacity facility ($800/kW). No information is currently available on marginal operating costs. Project sponsors are aiming for a 2011 construction date. DOE has been a major sponsor of the effort.

Of note, Southwestern Public Service (Xcel) in Texas recently worked with a company called Ridge Energy Storage and Grid Services to explore the value of compressed air technology as a method of mitigating transmission congestion associated with the high concentration of wind projects in West Texas. Although we have not explored this project in further detail, it presents an interesting conceptual approach to transmission planning and asset management in a high wind penetration environment.

Smart grid technologies - The next frontier

During the last 12-18 months, there has been a flood of venture capital and R&D money into new "smart grid" technologies. These include Vanadium Redux Flow Batteries and sophisticated demand-side methods for cycling loads. Few of these technologies are commercially viable at the moment, but some of them, such as flywheels -- which are now being tested as a source of regulating reserves with the California ISO -- are on the edge of commercial viability, and should not be written off as technological fantasy. Bonneville has investigated a number of these technologies as part of its Non-Wires pilot programs. In second phase of this work, we intend to conduct a thorough review, including estimates of cost, application, and timetables for development, of the next generation of flexibility technologies. In the interim, we have consulted with several of the nation's leading experts on next generation of flexibility technologies and summarized them in a matrix, attached as Appendix 3.

To conclude this section, we offer the following formal recommendation:

Hold a workshop on storage and system flexibility technologies: *The Northwest Power and Conservation Council, in collaboration with the DOE and the Energy Storage Association, should host a workshop on the future of storage and other system flexibility technologies and develop a work plan for identifying those technologies with most promise for meeting the long-term flexibility needs of the Northwest Power System. This plan should inform Bonneville's and other utility technology innovation programs. This plan should encourage demonstration of particularly promising technologies in the Northwest. Moderate priority, 2008.*

F. Develop a proactive regional strategy to maximize the economic and environmental value of wind power over the longer-term

Most wind power developed in the Northwest to date, and expected to be developed over the next several years lies in a limited geographic area east of the Columbia River Gorge. Driving the location of this development is a favorable wind resource, compatible land use and available transmission capacity to serve west side loads. Unfortunately, this geographic concentration produces strongly coincidental project output having little relationship to regional load patterns, as well as simultaneous ramping events increasing in magnitude as additional projects are developed. The latter is of concern because of the amount of operating reserves needed to accommodate potential ramping events.

From existing wind resource data, and observations of projects in BPA's control area, and studies that have been done in other regions, we expect that geographic diversification of wind projects, by reducing simultaneous ramping, may reduce the demand for system operating reserves.

Geographic diversification also may produce projects yielding higher capacity factors, and with better coincidence to loads, hours of higher electricity value or hours during which air emissions can be displaced. Examples of wind resource areas that could be accessed through construction of new transmission lines include the Dayton/Walla Walla (WA), Union County (OR), Livingston (MT), Blackfoot/Cutbank (MT), Martinsdale - Judith Gap (MT) and the basin and range ridges of southern Oregon and Idaho.

Geographic diversity, however, comes at the cost of new transmission lines, possibly including dedicated trunk lines to prime wind resource areas. Moreover, simultaneous enhancement of economic and environmental values may be difficult to achieve. Whereas the economic value of wind power is maximized when low-efficiency natural gas units are displaced, maximum environmental value is obtained when coal is displaced.

Another means of improving the economic and environmental value of wind power is through storage and shaping technologies. Pumped storage hydro or compressed air storage can shift wind plant output to high-cost or high-emission hours. However, while these technologies may be useful and economic for hourly or diurnal shifting, the economics of storage generally prohibits shifting to follow seasonal loads or extended leveling for purposes of improving transmission load factors. On the other hand, some storage and shaping technologies can provide other ancillary services, thereby enhancing their value.

An overall identification and assessment of strategies for maximizing the economic and environmental value of wind in the Northwest has not been attempted. One reason is the lack of necessary information concerning wind resources, transmission costs, and balancing, storage and shaping resources. Implementation of the recommendations of the Wind Integration Action Plan will result in the development of much of the information needed for this type of assessment over the next two years. Because of the potential benefits of proactively guiding wind resource development over the longer-term to maximize its economic and environmental value, we recommend that a comprehensive assessment of possible strategies be undertaken for the

Northwest. Because of its timing and scope, this effort should be coordinated with development of the Sixth Power Plan.

A further need is to develop an integrated regional transmission plan that incorporates all utility identified resources. A coordinated plan will allow the most effective expansion of the grid to address the needs of all utilities. It would also allow the selection of the best wind sites from a capacity and diversity perspective. The integrated plan requires a coordinating entity such as Columbia Grid and Northern Tier Transmission Group.

Assess the feasibility of a proactive long-term regional strategy to maximize the economic and environmental value of wind power for the Northwest: *Identify undeveloped or lightly developed wind resource areas showing promise for improving hourly or seasonal diversity of output or higher capacity factors. Assess the feasibility and cost of extending transmission to service these areas. Estimate the performance of wind projects sited in these areas and the resulting net impact on needed system balancing services. Examine the resulting net system value and environmental effects of various patterns of wind development. Assess possible costs and benefits of storage and shaping on these values and impacts.*

Depending upon the findings and conclusions of this work, we recommend a strategy for securing these values. Though of moderate priority relative to some other recommendations of this action plan, and requiring information called for in other recommendations of this action plan, we believe that work on this strategy should commence in 2007. Needed information includes the methodology for assessing system balancing requirements, the assessment of sustained peaking capacity value, improved wind resource data and future flexibility options (Finding/Recommendations I, V, VII & IX). This work should be coordinated with development of the Sixth Power Plan. Encourage rapid deployment of the planning functions in Columbia Grid and Northern Tier Transmission Group.

NORTHWEST WIND INTEGRATION ACTION PLAN
GLOSSARY & APPENDICES

Glossary (Under Development)

ACE, Area Control Error: The instantaneous difference between net actual and scheduled interchange between control areas, taking in to account the effects of frequency bias and including a correction for meter error.

ADI, Ace Diversity Interchange: The essence of ADI is that through coordination among multiple control areas, the control needed to balance load, interchange, and generation can be relaxed when compared with isolated operations. Relaxed control can be achieved because of the sign diversity (some are net positive or over-generating relative to load and some are net negative or under-generating relative to load) among area control errors.

AGC, Automatic Generation Control: Generation equipment that automatically responds to signals in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits

ATC, Available Transmission capacity:

CPS, Control Performance Standard: The reliability standard that sets the limits of Area Control Error over a specified time period.

Operating reserves: Operating reserves include the capacity needed to follow within-hour load variation net of wind (frequency regulation) as well as the capacity needed for hour-to-hour load following. As used in this report, operating reserves do not include capacity used to shape the output of wind projects over diurnal or seasonal periods.

OTC, Operational Transmission Capacity:

POS, Plan of Service:

RAS, Remedial Action Schemes: Protective systems that ensure that corrective actions take place immediately following the forced outage of a transmission line or transmission system element.

Renewable trunk line transmission: A radial transmission line primarily intended to serve multiple renewable resource projects located within a common large resource area.

Storage and shaping:

System flexibility: Electric utility system flexibility is the ability of both supply-side and demand-side resources to respond to changes and uncertainties in system conditions. Flexibility also refers to the ability of the hydro system to store water for delivery in future time periods.

Regulation: The portion of a generating unit's unloaded capability which can be loaded, or loaded capability which can be unloaded, in response to Automatic Generation Control signals. Regulation is used to provide control area balancing, frequency bias and time error correction

Appendix 1: Proposal for Development of Northwest Chronological Wind Data Set

Because of the need to think regionally about wind integration in the Northwest, a cooperative approach to securing a high-quality data set is proposed. This data set will be created from a large meteorological model, called a meso-scale meteorological model. This modeling can re-create the weather at any point in time and space, and can be used to construct detailed chronological wind speed and wind power data that represents wind generation in the region. The meso-scale modeling suggested below can be improved and informed by some existing wind data that has been offered for use by BPA (existing wind plants), PPM (existing wind generation), and Avista. Although these data cannot adequately represent the wind penetration to be investigated by the Northwest Wind Integration Forum (NWIF), they can be used to statistically correct the meso-model output, increasing the accuracy of the simulated wind data sets.

1. The NWIF intends to engage a firm (or firms) that can create 10-minute wind speed data using meso-scale weather models in the areas of potential wind development in the NW. The data set would ideally be 3 years long, and should represent the years' load shapes that will be used in the NWIF analysis. Because of the significant hydro generation resources in the area, the three-year period selected may represent high, median, and low water years. Average wind-speed every 10-minutes and at a 4km-square grid (minimum) for the NW would be simulated. Geographic areas within the footprint where wind development is likely to occur should be modeled at a higher-resolution grid, potentially as low as 1 km-square. However, the geographic resolution selected may also depend on the terrain, based on the judgment of the modeling team.
2. The data series should adequately represent the geographic dispersion impacts of the various wind scenarios. For one or more scenarios (determined by the project participants and budget) virtual anemometer data would be used to calculate power output in a way that would represent real wind plant output. This implies some limit to the wind capacity that could be represented by a single grid point, to be determined by the modeling team and the relevant geographical features of the region.
3. The region will include most of WA, OR, ID, and most of western MT. Small portions of western WY, northern UT, northern NV, and northern CA may also be included. The specific details will be determined jointly by the project team and may be subject to budget.
4. The project team will include individuals involved with the meso-scale meteorological simulations, members of the Data Committee of the NWIF, and members of the funding organizations.
5. Proposals for this work should address
6. Qualifications of the principals to do such work
7. Description of the data set that would be created and whether wind speed or power output will be provided to the NWIF

8. Recommendations on (a) geographic scope of the modeling, (b) geographic grid resolution that can be achieve, particularly in likely wind-development regions, (c) how the resulting data set could be used to create alternative wind generation scenarios in the Northwest.
9. Discussion of possible options to enhance the product if budget allows, and options to trim the product if budget is limited
10. The Wind Program at the National Renewable Energy Laboratory (NREL) has offered $100k of funding. Additional funding from the NWIF will be required.
11. The data that is derived from this project will be archived at NREL, the NWPCC, and any of the other funding sources.
12. The anticipated cost range per year of simulation is expected to be between $300,000 and $750,000, depending on technical details and scope of the geographic footprint, and the number of extraction points (virtual anemometers). This cost range would cover a 3-year data set.
13. The approximate elapsed time to provide this 3-year data set is approximately 2.5-3.0 months from execution of the project.

Appendix 2: The Language of Utility System Operations

The most important objective of an electrical utility is to meet its load obligations in a reliable, cost-effective manner. Long-term planners look out into the future and attempt to forecast **system loads** and **load variability** as well as other variables such as fuel costs, inflation, and expected market prices. They then determine which combination of power plants, demand-side techniques and market purchases will provide the greatest certainty of meeting peak load at the lowest overall cost. In most cases, they choose a combination of power plants with different generating characteristics. These include baseload plants with high capital and low operating costs, intermediate loaded plants with sufficient flexibility to follow the general trend in hourly load variation, and quickly dispatchable and flexible **peaking** facilities, often with low capital costs and high variable costs, designed for operation during periods of peak or super-peak load.

The long-term resource planner must also ensure that a portion of his generation fleet is capable of providing **governor response,** and operating with **Automatic Generation Control** to maintain appropriate voltages, and to handle changes in load/resource balance across both the very short (sub-second-to 10-minute) and intermediate (10-60 minute) time frame. Long-term resource planners are also concerned with building a sufficient **reserve margin** of generation above and beyond their peak load in order to demonstrate **resource adequacy** for purposes of meeting their peak load obligations.

Planning uses probabilistic models of different portfolios of resources to estimate the reliability of the system under different conditions of load and generator availability. The Power Council uses an analytical technique, known as **Loss of Load Probability (LOLP),** to assess the state of regional reliability. This type of analysis can also been conducted for wind generation. The increment of peak load that can be carried on a probabilistic basis by a generation resource has been equated to its **capacity contribution** or **capacity value** for the purposes of long-term planning.

Long-term transmission planning is conducted for transmission infrastructure requirements, with an eye to securing sufficient **transfer capacity** to move power from **points of receipt** to **points of delivery** across the transmission grid.

Power Marketers, Traders and Generation Schedulers (who collectively are referred to as the "merchant function" or "load serving entity") are charged with meeting load and optimizing the economic value of the power system that they inherit from the long-term resource planners. They conduct this optimization across a range of timeframes, including yearly, seasonal, monthly, balance of month, daily, and hourly. Their primary responsibility is to deploy that combination of available power plants and market purchases/sales that can meet load and monetize **surplus generation** at the lowest overall cost/highest net value to their organization. These merchants have access to several markets to assist in the balancing of their system needs. These include forward, day ahead, and real time markets. Trading for future months, while at times quite illiquid, is available during several business hours each weekday. Trading of power for day-ahead (or Fri/Sat, Sun/Mon, periodic 3-day) is conducted primarily each weekday morning from 6:00 am – 7:00 am. Electricity trading is conducted primarily for blocks of peak and off-peak

energy, although other products, such as super-peak energy, reserves, options, and exchanges also are bought and sold. There is also a 24-hour/day real time market for next-hour delivery that closes 30 minutes prior to the hour of delivery, i.e. trading for the 9:00 – 10:00 am time period closes at 8:30 am.

Prior to day-ahead trading, the load serving entity will generate a load forecast and generation estimate for each of its power plants to determine a net long or short position going into the next day. For systems with wind as part of the generation mix, the entity must also generate a forecast of wind generation for the next day. The entity will also develop an estimate of **load forecast error** and **wind forecast error** as additional factors in determining how much power to buy or sell for the next day. Most other power resources, if deemed **available**, will likely have lower forecast errors than wind facilities.

In the hourly time frame, the generation schedulers and real-time marketers primarily focus on meeting hour-to-hour changes in loads by adjusting the **basepoints** or **setpoints** of their fleet of **generation assets** and making **balancing sales and purchases**. The basepoint adjustments, or **ramps**, occur during the 20-minute interval from 10 to until 10 after each hour. Since there are no standard markets for within-hour electricity in the Pacific Northwest (the hourly real-time market being the shortest duration market available), generation schedulers use their basepoint adjustments to position their systems so that units on **Automatic Generation Control** or with fast-ramping capability can ramp up and down during the hour to adjust to the full range of motion of net system variability until the next basepoint adjustments are made. An estimate of wind energy generation for next hour will also be factored into the calculated basepoint adjustment for the next hour.

The within-hour timeframe between basepoint adjustments is the domain of the **Transmission Operator**. Transmission Operators are focused exclusively on system reliability. Their principle objective is to manage the frequency of the **Control Area** at 60 cycles (Hz) per second. To accomplish this, Transmission Operators must ensure that the system is carrying sufficient **operating reserves**. There are several categories of operating reserves with specific terminology. **Regulating reserves** are carried to manage minute to minute fluctuations in load and resource balance. These reserves are provided from spinning units with sufficient bi-directional capability to adjust to changes in system balance and minimize the **Area Control Error (ACE)** of the Control Area. ACE, which is expressed in MW, measures the instantaneous difference in scheduled and actual system frequency and a Control Area's scheduled and actual interchanges with other Control Areas.

The Transmission Operator must also ensure that the system is carrying sufficient **contingency reserves** to cover unanticipated losses of generation or transmission elements. According to **Western Electricity Coordinating Council (WECC)** requirements, Control Areas must carry the greater of a combination of 5% of hydro generation and 7% of thermal generation, or their most severe single contingency. Half of the required contingency reserves must be on line and spinning, the remainder must be able to be brought on line and loaded within a ten minute period. The Northwest Power Pool requires 5% contingency reserves for wind generation. Control Areas must also carry sufficient reserves for any scheduled interruptible imports and on-demand obligations that they have. Performance is measured by a set of **NERC Control**

Performance Standards, known as **CPS1**, **CPS2**, and a **Disturbance Control Standard (DCS)**, which measure an entity's ability to follow system frequency, regulate load, and recover from system disturbances.

Generators, including wind, may be required submit a **generation schedule** to the Control Area's transmission scheduling desk prior to the hour of operation. If a resource deviates from its schedule during the hour, it will contribute to variations in net system balance during the hour and these variations will be offset by those generation units providing regulating reserves (or contingency reserves in the case of a major outage) to the Control Area. At the end of each hour, average hourly positive or negative deviations from schedule, in MWh, are calculated by the transmission provider and a financial penalty is assessed to the generator that is subject to contract or tariff terms. These penalties include payments by the generator for not meeting a schedule, or reduced payments for exceeding the schedule.

Appendix 3: Flexibility Augmentation Technologies

	Capital Cost (per kW basis)	Operating Cost	Footprint (m2/kW)	Life (yr)	Lead Time	State of Technology	Where Sited	Locational Constraint	Scalable	Ease of Addition to Existing System	Efficiency and Losses	System Flexibility Applications [21]
Storage Technologies												
Capacitors/ Ultracapacitors	High	Low	Small	10-15	Long	In development	Load	CS	No	Yes	Good	FR/LF
Conventional Batteries	Low	Low	Small	7	6 months	Mature	S-L	CS	Yes	Yes	OK	FR/LF/SR
Flow Batteries-Flow/Redox [vanadium, zinc bromine, cerium zinc, polysulphide bromine, etc.]	High	Medium	Small	10 - 15	medium	Beta	S-L	CS	Yes	PCS dependent	OK	FR/LF/SR
Other battery technology (e.g., lithium ion)	High	Low	Small	7	No large systems in place	None in MW size	Load	CS	Yes	PCS dependent	OK	FR/LF/SR
Compressed Air [tanks, salt-domes]	High	Low requires natural gas	Tanks – Large Dome - small	decades	Medium	Mature for cavern	Source ???	Geology yes, tanks no	Geology no, tank yes	Geology no, tanks yes	Good	FR/LF/SR LF/DS/SS

[21] FR - Frequency regulation
LF - Within-hour load following
DS - Diurnal to week-ahead storage
SS - Seasonal storage
SR - System reliability capacity

Flywheels	Unknown	Low	Medium	decades	No MW yet	Alpha	S-L	CS	Yes	Yes	Good	FR/LF
Pumped storage hydro	Moderate	Very Low	Large	decades	10 yrs	Mature	Unique sites	Geology	No	No ???	Very good	FR/LF/DS/SS/SR
NAS Battery	High	Low	Small	10 yrs	1 yr	Early commercial	S-L	CS	Yes	PCS dependent	Good	FR/LF/SR/DS
Fuel Synthesis Storage Technologies												
Ethanol	High	Low	Large	decades	3 yr+	Early commercial	S-L	Yes	No	No	?	DS/SS/SR
Hydrogen	High	Very high	Large	decades	5 yrs+	Beta	S-L	No	Yes	No	50% max	DS/SS/SR
Generation Technologies												
Simple-cycle GT /Recip Engine	Low	High	Medium to Large	decades	3 yrs +	Mature	Source	yes	yes	OK	60%	LF/SR
Duct firing (combined-cycle GT)	Low	Low	Medium to Large	Decades	Only at construction	Mature	Source	Yes	No	OK	Good	LF/SR
Fuel cells	High	Low	Medium	5 -10 yrs	2 yrs	Beta	S-L, fuel limited	CS	Yes	PCS dependent	50%	LF?
Add capacity to existing hydro projects	High	Low	Small	Decades	2-5 yrs	Mature	Source	Yes	Limited	OK	Good	FR/LF/DS/SS/SR
Call rights on standby generation	Low	High	Small	N/A	1-3 yrs	Mature	Load	yes	yes	OK	30%	LF/SR
Demand-side options												
Call rights on plug-in auto fleet	High	Low	N/A	N/A	Unknown	Conceptual	Load	yes	yes	No	Good	FR/LF/DS/SR
Load interruptibility rights	Low	High	N/A	Contract life	1 yr +	Mature	Load	yes	yes	Ok	n/a	LF/SR
Dispatchable load cycling	Low	Low	N/A	10+ yrs	1-3 yr +	Mature	Load	yes	yes	Ok	n/a	FR/LF/SR
Distributed Generation	Moderate - High	High	N/A	Decades	1 yr +	Early Commercial	Load	No	Limited	Ok	30%	LF/SR

Operational techniques												
Stretching wind prediction time	Can it be done?	Low	N/A	N/A	Years?	Beta	Source	Yes	No	No	n/a	SR
Wind plant dispatch control	?	?	N/A	N/A	Contract based	Mature, like load interrupt	Source	Yes	Yes	?	n/a	LF?