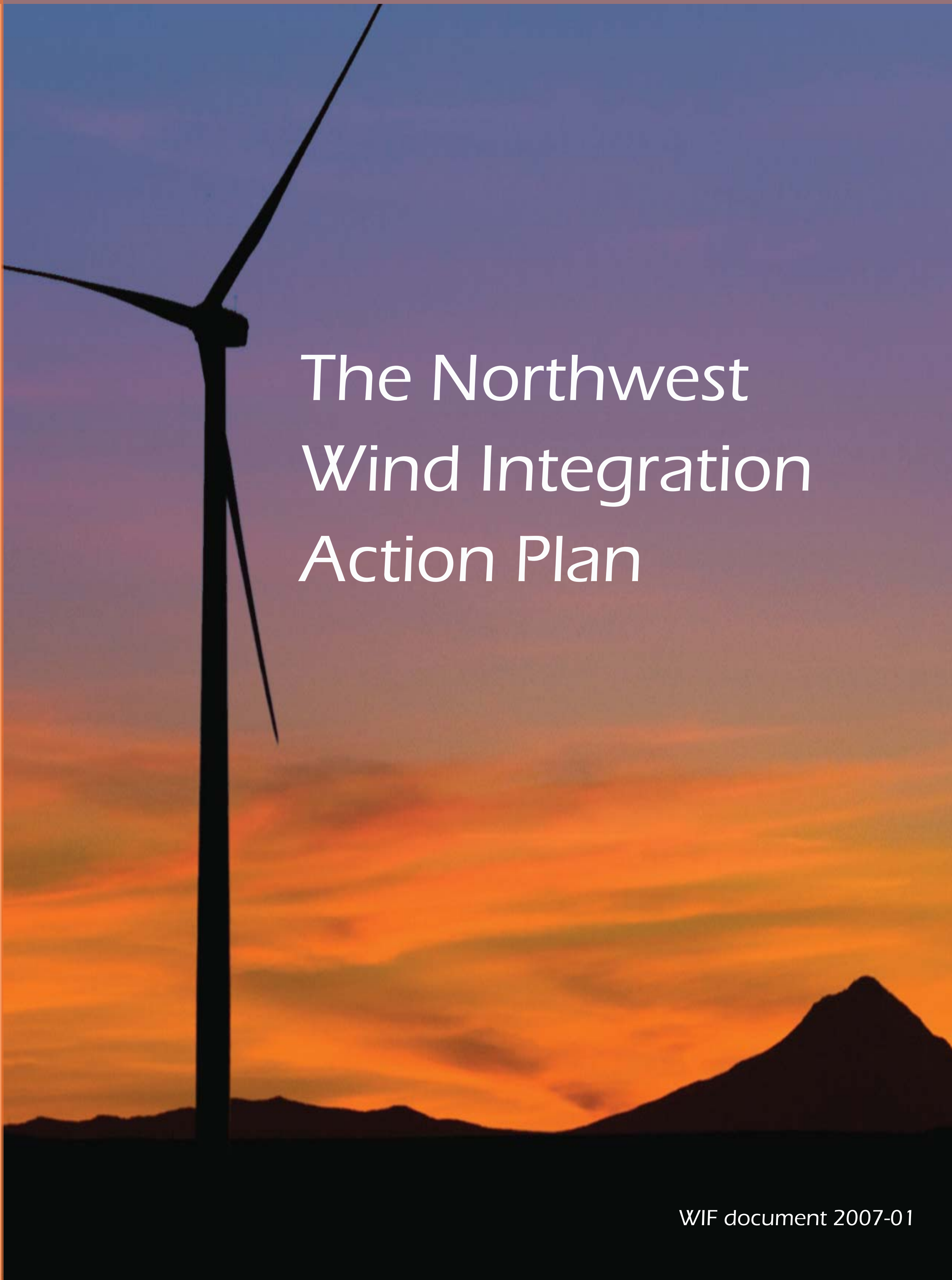


The Northwest Wind Integration Action Plan

WIF document 2007-01

FSC

Recycle content 50/25%

© 1996 Forest Stewardship Council

This report was printed on paper that features high recycled content compared to both foreign and domestic grades.
(50% overall / 25% post-consumer)

Copies of this report are available from the
Northwest Power and Conservation Council
851 SW Sixth Avenue, Suite 1100
Portland, Oregon 97204
503-222-5161
www.nwcouncil.org

Cover Photo: Klondike II wind project.
Photo courtesy of Leon Werdinger, www.ottertrack.com

Northwest Wind Integration Action Plan

March, 2007

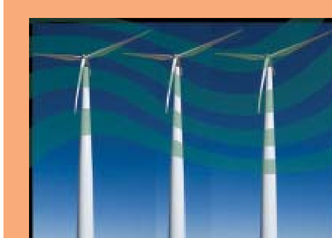
Participating Organizations and Individuals

Steering Committee

Tom Karier, Northwest Power and Conservation Council, Co-Chair
Stephen J. Wright, Bonneville Power Administration, Co-Chair
Walt Pollock, Facilitator
Jorge Carrasco, Seattle City Light
Teresa Conway, Powerex
Tim Culbertson, Grant County Public Utility District
Bill Drummond, Western Montana Electric Generation & Transmission
Angus Duncan, Bonneville Environmental Foundation
David Gates, NorthWestern Energy
Terry Hudgens, PPM Energy
Greg Jergeson, Montana Public Service Commission
Jim Kempton, Northwest Power and Conservation Council
Paul Kjellander, Idaho Public Utility Commission
Jim Lobdell, Portland General Electric
Eric Markell, Puget Sound Energy
Louise McCarren, Western Electric Coordinating Council
Jim Miller, Idaho Power Company
Kelly Norwood, Avista Corporation
John Prescott, PNGC Power
John Savage, Oregon Public Utility Commission
Rachel Shimshak, Renewable Northwest Project
Marilyn Showalter, Public Power Council
Brian Skeahan, Cowlitz County Public Utility District
Stan Watters, PacifiCorp

Technical Work Group

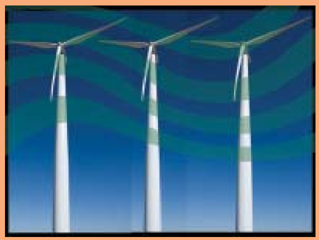
Jeff King, Northwest Power and Conservation Council, Co-Project Manager
Elliot Mainzer, Bonneville Power Administration, Co-Project Manager
Frank Afranji, Portland General Electric
John Apperson, PacifiCorp
Philip Augustin, Portland General Electric
Jamie Austin, PacifiCorp
Bryan Baldwin, Montana Public Service Commission
Steve Barton, Bonneville Power Administration
Rebecca Berdahl, Bonneville Power Administration
Sarah Bermejo, Bonneville Power Administration
Karl Bokenkamp, Idaho Power
Lowrey Brown, Citizens' Utility Board of Oregon
Stefan Brown, Oregon Public Utilities Commission



Ray Brush, NorthWestern Energy
Grant Brohm, WindLogics
Ron Brzezinski, General Electric
Phil Carver, Oregon Department of Energy
Kevin Conway, Grant County Public Utility District
Carel DeWinkel, Oregon Department of Energy
Robert Dies, CDD Howard
Bo Downen, Public Power Council
Ken Dragoon, Renewable Northwest Project
Jim Eden, Portland General Electric
Steve Enyeart, Bonneville Power Administration
Doug Faulkner, Puget Sound Energy
Larry Felton, Energy Northwest
David Fine, NorthWestern Energy
Bruce Folsom, Avista
Thomas Fung, British Columbia Transmission Corporation
David Gilman, Bonneville Power Administration
Kurt Granat, PacifiCorp
Roger Hamilton, Wind on the Wires
Mike Heckler, Windland, Inc.
Joe Hoerner, Puget Sound Energy
Mike Hoffman, Bonneville Power Administration
Pamela Jacklin, Stoel Rives
Mark Jackson, Bonneville Power Administration
Mike Jacobs, American Wind Energy Association
Casey Johnston, NorthWestern Energy
Hardev Juj, Seattle City Light
Clint Kalich, Avista
Mike Kelly, Horizon Wind Energy
Brendan Kirby, Oak Ridge National Laboratory
Mark Lively, Lively Utility
Diane Lozovoy, PacifiCorp
Gordon Dobson-Mack, Powerex
Yuri Makarov, Pacific Northwest National Laboratory
John Martinsen, Snohomish Public Utility District
Chuck Matthews, Bonneville Power Administration
Jack Mayson, Regulatory & Cogeneration Services
Natalie McIntire, Renewable Northwest Project
Bart McManus, Bonneville Power Administration
Jeff Miller, PacifiCorp
Michael Milligan, National Renewable Energy Laboratory
James Murphy, Bonneville Power Administration
Tom Murphy, Bonneville Power Administration
Irena Netik, Puget Sound Energy
Huyen Nguyen, Puget Sound Energy
Kevin Nordt, Grant County Public Utility District
Rod Noteboom, Grant County Public Utility District
Dan O'Hearn, Powerex

Brian Parsons, National Renewable Energy Laboratory
Bill Pascoe, Pascoe Energy
John Pease, Bonneville Power Administration
Lon Peters, Northwest Economic Research, Inc.
Chris Reese, Puget Sound Energy
Mike Ryan, Portland General Electric
Irion Sanger, Industrial Customers of Northwest Utilities
Steve Saylors, Vestas
Howard Schwartz, Northwest Power and Conservation Council
Joe Seabrook, Puget Sound Energy
Paul Schmidt, Sierra Pacific Power Company
Marilynn Semro, Seattle City Light
Brian Silverstein, Bonneville Power Administration
Charlie Smith, Utility Wind Integration Group
Mark Smith, FPL Energy
Steve St. Clair, Puget Sound Energy
Rick Sterling, Idaho Public Utilities Commission
Pascal Storck, 3TIER Environmental Forecast Group
Jaison Tsikirai, PacifiCorp
Chris Turner, Seattle City Light
Scott Waples, Avista Corporation
Mark Widmer, PacifiCorp

Editor: Deston Nokes, Bonneville Power Administration
Design: Stephen Sasser, Northwest Power and Conservation Council
Fawn Williams



Photos courtesy of PPM Energy.

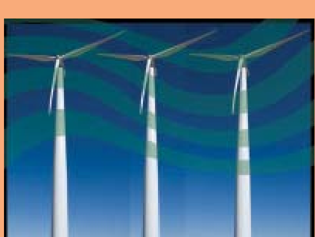


Table of Contents

Over the next three years, as much as 2,400 MW of wind power is expected to come online in the region, for a total of nearly 3,800 MW by 2009.

Introduction and Executive Summary

The Pacific Northwest, already blessed with abundant hydroelectricity, is now seeing rapid growth in another of its renewable energy resources – wind power.

Less than a decade after the region's first commercial-scale wind project came online in 1998 (the 25-megawatt Vancycle project in Eastern Oregon), nearly 1,400 megawatts (MW) of wind generation have connected to the grid. Over the next three years, as much as 2,400 MW of wind power is expected to come online in the region, for a total of nearly 3,800 MW by 2009. The Northwest Power and Conservation Council's Fifth Northwest Electric Power and Conservation Plan (Fifth Power Plan) includes up to 6,000 MW of developable and potentially cost-effective wind power. The Fifth Power Plan also calls for the development of a wind confirmation plan to resolve uncertainties surrounding wind power development. This Action Plan serves that purpose.

Many factors are driving wind energy's growth, including volatile natural gas prices, and renewable energy and climate 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.
- Montana adopted a renewable portfolio standard of 15 percent by 2015.
- Washington's electorate adopted Initiative 937, 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.

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

Through this Northwest Wind Integration Action Plan (Action Plan), many of the region's utility, regulatory, consumer and environmental organizations have worked together to address several major questions surrounding the growth of wind energy.

These include:

- **What is the role of wind energy in a power supply portfolio and how does it impact system operations?**
- **Does the Pacific Northwest have the operational capability to integrate 6,000 MW of wind? If so, what are the estimated costs of integrating this amount of wind energy?**
- **What are the 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 Northwest meet its wind energy potential in the most cost-effective manner?**

This effort has produced significant findings regarding the ability of the Northwest to accommodate future wind power development. The effort also has identified issues that need to be resolved for wind power to achieve its full potential. This Action Plan recommends 16 actions intended to help resolve these issues. Of particular importance are actions addressing challenges associated with transmission marketing, planning and expansion, and the limited market for control area services. A final action calls for the formation of a Northwest Wind Integration Forum to facilitate implementation of the Action Plan. There is a summary of the major findings and action items on page 14.

The role of wind energy in a power supply portfolio

The fundamental value of wind power to a utility portfolio lies in its ability to displace fossil fuel consumption, limit exposure to volatile fossil fuel prices, and hedge against possible greenhouse gas control costs.

Wind is primarily an energy resource that makes relatively little contribution to meeting system peak loads. Even with large amounts of wind, the Northwest still will need to build other generating resources to meet growing peak load requirements. Wind energy is a renewable, clean energy resource that will lower the fuel consumption and environmental emissions of other resources. But wind energy cannot provide reliable electric service on its own.

When wind energy is added to a utility system, its natural variability and uncertainty is combined with the natural variability and uncertainty of loads. This increases the need for flexible resources such as hydro, gas-fired power plants, or dispatchable loads to maintain utility system balance and reliability across several different timescales. The demand for this flexibility increases with the amount of wind in the system.

Operational capability and costs of integrating wind in the Northwest

Initial wind integration studies by Avista, Idaho Power, BPA, Puget Sound Energy and PacifiCorp find no fundamental technical barriers to achieving the Council's target of 6,000 MW of wind. It's a question of cost.

Conceptually, the cost of wind integration starts low, as the amount of variability introduced by a small amount of wind is virtually lost in the larger fluctuations of loads. As the amount of wind increases, the effects of wind variability dominate the effects of load variability, and flexibility needs to be added to the system in direct proportion to the growing wind penetration[1]. Access to large amounts of existing system flexibility, such as that provided by the region's hydroelectric resources, can help minimize the costs of wind integration and postpone the need for investments in other sources of system flexibility.

Table 1: Wind integration costs, at various levels of penetration, from investor owned utility studies[1,2,2A] ($/MWh of wind generation)

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	$2.75	$6.99	$6.65	$8.84
Idaho Power	3,100	Not run	$9.75	$11.72	$16.16
Puget Sound	4,650	$3.73	$4.06	Not run	Not run
PacifiCorp	9,400	$1.86	$3.19	$5.94	Not run

Table 2: Wind integration costs, at various levels of penetration, from BPA study[1,2A]($/MWh of wind)

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA (Within-Hour Impacts Only)	9,090	$1.90	$2.40	$3.70	$4.60

The fundamental value of wind power to a utility portfolio lies in its ability to displace fossil fuel consumption, limit exposure to volatile fossil fuel prices, and hedge against possible greenhouse gas control costs.

[1]Penetration is defined as installed wind divided by peak load.
[2]The Avista 20% and 30% penetration figures assume a much larger geographic footprint than its 5% and 10% scenarios. The benefits of geographic diversity are apparent in that a doubling of wind generation comes at a lower cost than the less-diversified 10% case. As the 20% and 30% penetration cases assume the same wind plant geography, integration costs rise from 20% to 30%.
[2A]Avista, Idaho Power, PacifiCorp and Bonneville values are in year 2001 dollars. In the analysis ,the Puget Sound Energy year dollars are not reported.

Costs ultimately plateau at the cost of procuring system flexibility from natural gas-fired power plants.

Preliminary cost estimates from the initial Northwest wind integration studies are cited below. The studies represent a significant step forward in regional understanding of wind integration costs. But it should carefully be noted that the cost figures and methodologies underlying the studies are still the subject of debate among members of the Technical Work Group who worked on this document. Revisions to several of the studies are still under way. All of the utilities reporting results intend to revisit their study methodologies and results as better data and analytical techniques become available.

The cost estimates will eventually be translated into formal rates and/or market prices that may deviate from the numbers cited. The cost estimates are also based on current system obligations and constraints that are subject to change. Future reductions in system flexibility could result in higher costs. The costs may also come down as a result of ongoing study revisions, greater control area coordination, or other cost-reduction strategies.

The most current, officially released study results are posted on the Council's Website at **www.nwcouncil.org/energy/wind** and will be updated on a regular basis.

The Avista, Idaho Power, Puget and PacifiCorp studies evaluated both the within-hour and hour-to-hour costs of integrating wind for native load service. The BPA study was initially limited to within-hour costs in order to inform tariff and rate revisions that will be required to recover the costs of integrating wind projects serving nonfederal loads. As a result, the BPA integration cost estimates are shown separately and likely represent a low-end estimate for the BPA system, as the federal agency has yet to formally assess hour-to-hour costs.

The studies received an initial round of peer review, but the peer review process created for this project was not completed in time for the release of this report.

The cost estimates are based on current system obligations and constraints. Future reductions in system flexibility could result in higher costs as could changes in other market variables that influence these costs. All of these cost estimates eventually will be translated into formal rates and/or market prices that likely will include other factors such as risk and prevailing market dynamics.

Based on Northwest studies and others from around the world, the cost of wind integration largely is dependent on: (1) the size of the control area from which such services are procured in relation to the amount of wind being integrated; (2) the geographic diversity[3] of wind sites and resultant generation patterns; (3) the amount of flexibility available to the power system, and (4) access to robust markets for control area services and storage and shaping products.

With increasing amounts of wind, there likely will be times when large, unexpected changes in wind output ("ramping events") coincide with periods of limited system flexibility. Initial analyses indicate that these will be low-probability events, but in some instances, system operators will need to limit wind output for brief periods in order to maintain system reliability. The Federal Energy Regulatory Commission now requires wind plants to help protect system reliability. Northwest utilities and developers are collaborating to implement this requirement in a mutually satisfactory and cost-effective manner.

[3]Diversity in this context refers to the extent to which changes in wind output at one wind site are different from the changes at other wind sites.

Wind integration studies have been performed on a variety of systems and wind penetration levels both within and outside the United States. Care must be taken when comparing these studies because of differences in regional market structures and other variables. In general, the studies have found that wind integration costs are a significant, but not a dominating portion of total wind resource costs, up to wind nameplate penetration levels of 20-to-30 percent of peak load. In addition to wind integration costs, a full economic assessment of the value of wind energy to a utility portfolio must consider other variables. These include the daily and seasonal pattern of wind generation, the busbar price and environmental emissions of wind compared to other generating resources, the costs of transmission, and the benefits of a relatively fixed-price resource with no exposure to carbon legislation.

The Northwest does not possess wind data adequate to quantify the benefits of cooperative operational strategies, to evaluate the benefits of geographical diversification, to inform transmission planning efforts, and to evaluate fully the capacity value of wind. A multiyear, high-resolution, synthetic data set should be developed to support these analyses.

Transmission requirements for integrating 6,000 MW of wind

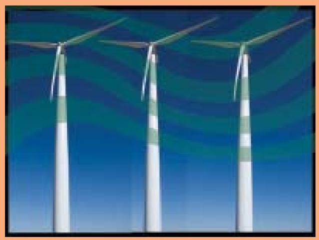
The amount of transmission capacity that is currently available to Northwest wind projects is only sufficient to support anticipated development through 2009. Additional transmission capacity will be needed to achieve the 6,000 MW of wind envisioned in the Council's plan and to open up new areas for wind development that will diversify wind production. This diversity can reduce total variability and therefore lower the cost of wind integration on a $/MWh basis. It can also provide access to higher capacity factor wind resources, which can lower the busbar costs of wind generation.

While firm transmission is necessary to secure the capacity value of a conventional generating plant, the economically optimal approach for a variable resource with limited capacity value like wind is to seek a mix of firm, nonfirm or conditional firm transmission that balances the marginal cost of transmission and the marginal value of delivered wind energy. Achieving this balance will require a combination of transmission expansion, new commercial practices and new regulatory policies. It also may require reallocation of risk and compensation between project owners and purchasing utilities to enable wind project financing.

Increasing congestion in key sections of the Northwest transmission network, including the West of McNary Corridor, the I-5 Corridor, the North Cross-Cascades Corridor and South Cross-Cascades Corridor, suggests that steps to prepare for eventual construction of these projects are prudent. Plans of service and business case assessments should be completed for each. Environmental assessment and other preconstruction activities would follow a favorable business case in order to secure at least the option to build the lines. Studies should be undertaken to evaluate the costs and benefits of extending transmission capacity to Montana and other prime wind resource areas.

Products and strategies that make better use of existing transmission lines, such as conditional firm and voluntary economic redispatch, may enable new wind projects to come online before new transmission lines are constructed, or extend the time until transmission construction is required. A pilot voluntary economic redispatch program, with the initial objective of using existing West of McNary transmission as effectively as possible, should be developed and tested.

The Northwest does not possess wind data adequate to quantify the benefits of cooperative operational strategies, to evaluate the benefits of geographical diversification, to inform transmission planning efforts, and to evaluate fully the capacity value of wind.



By the end of 2007, BPA may have as much as 1,500 MW of wind in its control area – much of it serving nonfederal loads.

Judith Gap Wind Energy Center, Montana.
Photo courtesy of NorthWestern Energy.

Eventual construction of new transmission will require a financing model for projects that largely are driven by new generation development. The financing model 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.

BPA is working with regional stakeholders to develop a generally applicable approach for financing and recovering the costs of partly or wholly market-driven transmission projects using West of McNary as a prototype. Ideally, the approach would also be applicable to renewable trunk line transmission.

Wind integration cost recovery

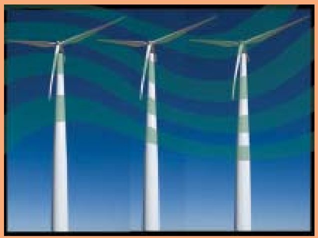
Current tariff and rate provisions may not be sufficient to recover the costs of wind integration in all cases. Cost recovery and allocation is a threshold issue for each control area and there are diverse opinions about the point at which these costs warrant developing a new tariff, and how that tariff should be designed and applied. All seem to agree that there should be a defensible basis for determining any additional costs resulting from wind resources interconnecting in a control area.

The cost threshold has been reached at BPA. By the end of 2007, BPA may have as much as 1,500 MW of wind in its control area – much of it serving nonfederal loads. In 2007, BPA expects to revise its approach to recovering and allocating wind integration costs through formal rate case proceedings. Sales of wind integration services will not compromise BPA's statutory obligations to its requirements customers.

Regional efforts to reduce integration costs

Coordination among utilities in the Northwest, in order to realize the benefits of a variable and relatively low capacity factor renewable resource, has a distinguished history in the Pacific Northwest. Both the Pacific Northwest Coordination Agreement (PNCA) and the Columbia River Treaty brought the benefits of hydro generation diversity and energy storage sharing to the region. Those benefits were used to help finance construction of the Pacific NW-SW transmission intertie. Regional coordination of wind resources can net similar savings and benefits.

The cost of wind integration rises as the percentage of wind grows on the interconnected system. For example, integration costs of a 100 MW wind facility on a control area with a peak of 500 MW (20 percent penetration) is much higher than the same facility hosted by a 5,000 MW control area (2 percent penetration). This cost differential is due to the fact that the larger control area already has enough flexibility to manage large load fluctuations. Short of actual control area consolidation, the two most significant steps toward realizing this benefit are the development of expanded wholesale markets for control area services and greater operating reserve sharing. If successful, these steps can help shift the existing wind integration supply curve to the right.



Developing more robust markets for control area services will provide needed electric services for smaller control areas with substantial wind resources, such as NorthWestern Energy in Montana. Without access to such markets, development of otherwise cost-effective and diverse wind resources is at risk. Development of such markets can be accomplished within the framework of the Northwest's current market structure.

Building on existing contingency reserve sharing agreements, several Northwest utilities are participating in a pilot program to share Area Control Error (ACE) through the ACE Diversity Interchange project. Lessons learned from this effort may help solve some of the technical and institutional barriers to more robust markets for control area services and greater operating reserve sharing.

Wind integration studies performed in the Northwest and other regions have concluded that the demand for operating reserves and resulting wind integration costs are very sensitive to wind forecast accuracy. The potential of a regional wind forecasting network to reduce wind integration costs, and to provide added value to participating utilities and wind project operators, should be investigated.

In the future, new technologies such as pumped storage, compressed air and demand management may play a greater role in providing system flexibility. However, at present, the principle alternative to hydro generation for providing system flexibility is natural gas-fired generation. In an increasingly carbon-constrained world, the tradeoffs between losses of hydrosystem flexibility and greater reliance on fossil-fired generation to integrate wind, need to be formally evaluated alongside other tradeoffs between competing uses of system flexibility. The Council can initiate this assessment through Action GEN-9[4] of its Fifth Power Plan. In addition, future power plans should explicitly consider the tradeoffs between transmission investment, improved wind project performance through geographic diversification and the cost of flexibility augmentation options.

[4] Text of GEN-9 from Fifth Power Plan:
ACTION GEN-9: The Council will assess the effects of shaping wind power on other functions of the hydropower system – A better understanding of the possible effects of shaping large amounts of wind capacity on the hydropower system is essential to correctly valuing shaping services and to establishing possible operational limits on those services in order to avoid adversely affecting other hydropower system operations. The Council will take the lead in devising and conducting an assessment of these effects. BPA, the Corps of Engineers, utilities having hydropower resources suitable for shaping wind energy, and other stakeholders are encouraged to participate in this assessment.

Summary of Action Plan items

A summary of the recommended actions follows. Additional detail regarding these recommendations is provided in Section VI of this report.

1) The Northwest Resource Adequacy Forum should reassess its 15 percent pilot sustained wind capacity value.

2) Northwest utilities should continue to refine their estimates of wind integration costs using a robust stakeholder process and develop estimates of potential cost reductions from control area cooperation, more active markets for control area services and other strategies.

3) The Northwest Wind Integration Forum should contract for the development of a high-resolution wind resource data set for the Pacific Northwest.

4) The Northwest Transmission Assessment Committee (NTAC) should propose a formal technical transmission planning methodology that seeks a balance between the cost of transmission capacity and the value of delivered wind energy.

5) Columbia Grid and the Northern Tier Transmission Group, together with NTAC, should begin applying the NTAC transmission planning methodology to regional transmission planning.

6) The four state regulatory commissions should review and amend as necessary regulatory policies to remove barriers to more efficient use of transmission for wind and other renewable resources.

7) BPA and other Northwest parties should explore ways to make more efficient use of existing transmission infrastructure, such as conditional firm transmission service and redispatch.

8) BPA should complete plans of service and review the business cases for the proposed West of McNary, I-5 Corridor and Cross-Cascades transmission reinforcements.

9) BPA should develop a general model for financing market-driven transmission improvements, using the proposed West of McNary project as a prototype.

10) NTAC, building on the results of the Rocky Mountain Area Transmission Study (RMATS), should evaluate approaches to delivering wind energy from Montana such as an upgrade of the 500kV system in Montana, and evaluate opportunities to deliver wind energy from other isolated wind resource areas.

11) The Northwest Wind Integration Forum should evaluate the costs and benefits of a regional wind forecasting network and, if positive, develop an implementation plan.

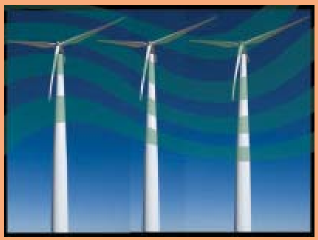
12) The participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

13) The Northwest Wind Integration Forum should address barriers to expanding the market for control area services and wind integration products.

14) The Northwest Wind Integration Forum should characterize options for augmenting system flexibility. The Northwest Power and Conservation Council (Council) should complete Action GEN-9 of its Fifth Power Plan to improve understanding of the tradeoffs between competing uses of system flexibility in an increasingly carbon constrained environment.

15) The Council, in future power plans, should incorporate a planning framework to maximize the economic and environmental value of wind energy.

16) The Council, working with BPA and other interested organizations, should establish a Northwest Wind Integration Forum to facilitate implementation of the actions called for in this Action Plan.



I. The role of wind energy in the Northwest power system

Wind energy displaces fossil fuels and reduces exposure to price volatility

Wind power is a zero-emission energy resource with no fuel costs. The primary benefits of wind energy are displacement of fossil fuels and their associated emissions and carbon dioxide production, and reduced exposure to natural gas price uncertainty and volatility.

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 needs. Wind is added for its environmental, economic and risk reduction benefits. Additional utility risk reduction benefits can accrue from the ability to construct wind projects to match the timing and scale of load growth.

An analysis performed by the Council indicates that in the Northwest, a new, must-run resource such as wind generation will displace natural gas more than 80 percent of annual hours[5]. In this analysis, coal was displaced about 10 percent of hours and other resource types the remaining hours. The economic and environmental benefits of fuel displacement are a function of the fuel, heat rate and emissions control characteristics of the displaced resource. This pattern of displacement 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). However, it would be preferable from an environmental perspective to displace coal instead of natural gas, as CO2 and criteria pollutant[6] reductions would be greater.

Northwest wind resources and wind project development

The Pacific Northwest has many good, though scattered, wind resource areas. A good wind resource area receives sustained strong winds averaging seven meters per second (16 mph) or more[7]. The area will have smooth topography and low vegetation to minimize turbulence, sufficient developable land to achieve economies of scale, nearby transmission lines with available capacity, complementary land use and an absence of sensitive species, habitat, cultural features and aesthetic qualities. Ideally, daily and seasonal wind patterns will coincide with electrical load.

The red, purple and pink areas of Figure 1 indicate potentially productive wind resource areas. Land east of the gaps in the Cascade and Rocky Mountain ranges receive concentrated, prevailing, storm-driven westerly winds, as well as wintertime, northerly winds. This also occurs in Washington's Kittitas County, the Columbia River Plateau east of the Columbia River Gorge and the Blackfoot area east of Montana's Marias Pass. Ridges perpendicular to prevailing winds in the Basin and Range areas of southeastern Oregon and southern Idaho also receive strong winds. East of the Rocky Mountains, nearly any landform above the general elevation will have good winds. There, wind is concentrated at gaps between local ranges, such as at Judith Gap in Montana.

The primary benefits of wind energy are displacement of fossil fuels and their associated emissions and carbon dioxide production, and reduced exposure to natural gas price uncertainty and volatility.

[5] Northwest Power and Conservation Council. "Power System Marginal CO2 Production Factors." Whitefish, Montana, April 2006.
[6] These include oxides of sulfur, oxides of nitrogen, particulates, hydrocarbons and mercury.
[7] At 50 m elevation

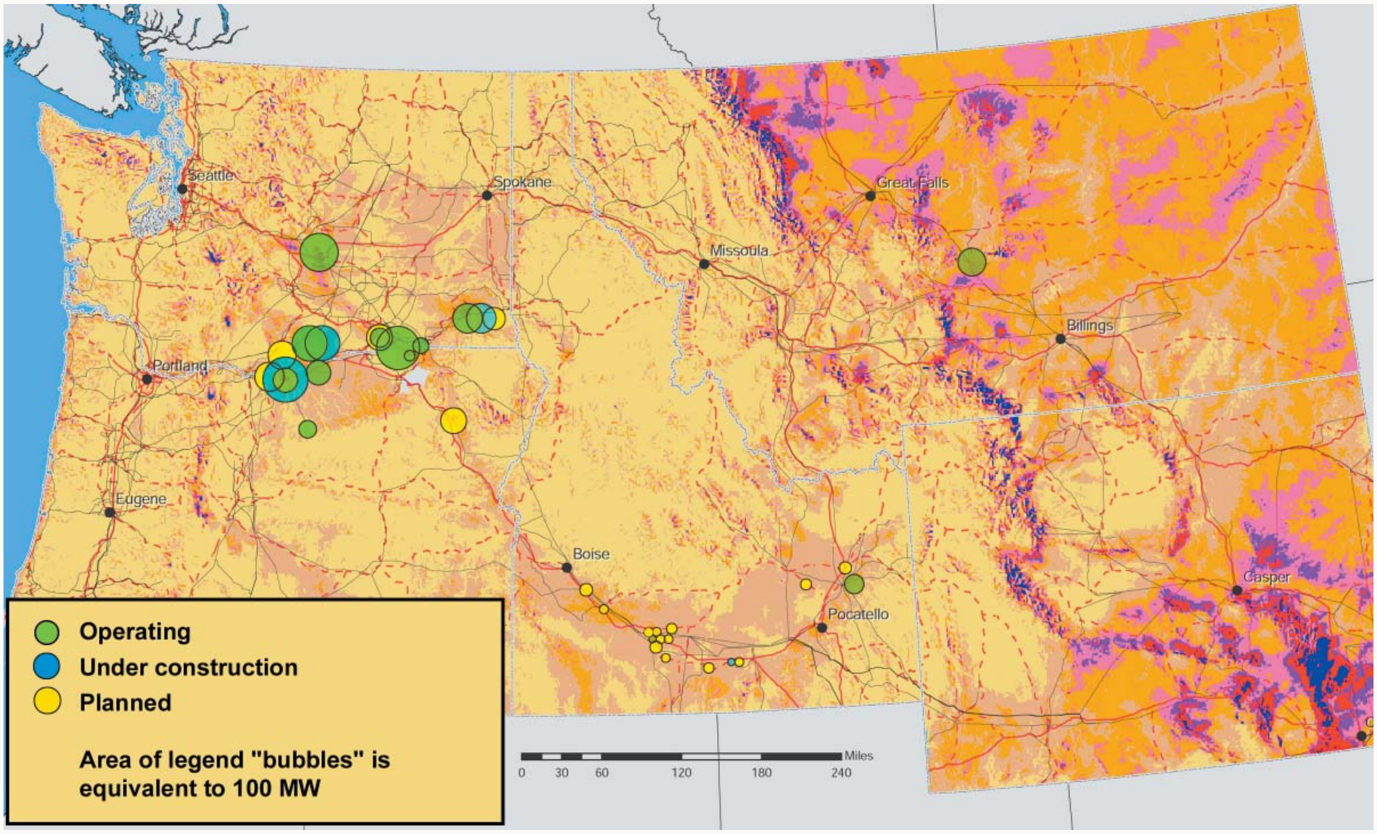
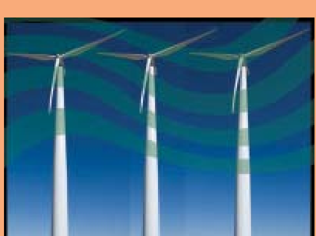


Figure 1: Northwest wind resources and wind project development

Because of complex topography, land use and environmental limitations, not all of the good wind resource areas shown in Figure 1 will be developable. Wind power development in coastal areas, for example, will be constrained by steep topography, forest cover and aesthetic concerns.

Wind power development in the Northwest has been largely concentrated in areas of compatible land use (open range and dryland wheat farming), favorable wind and access to available firm transmission capacity to the load centers west of the Cascades. The circles in Figure 1 represent individual projects and are proportional in area to installed capacity. Green circles are projects in commercial service and blue are projects under construction as of December 2006.

The concentrated development to the east of the Columbia River Gorge is evident. Of the 2,170 MW of wind projects in service and under construction regionwide, 875 MW (40 percent) are within the McNary-John Day transmission corridor just east of the Gorge. Another 425 MW (20 percent) lie slightly further east in the Wallula Gap-Walla Walla area. While not having the best wind resources of the region, this area has compatible land use, reasonably favorable wind, and, to date, sufficient available firm transmission capacity with access to the load centers west of the Cascades. The concentration of wind projects in this area will continue to grow in the near-term. The yellow circles represent planned projects with announced contracts for which construction is expected to begin within the near future[8].



[8]Planned" projects shown in Figure 1 are those with announced power sales agreements or intention to proceed, a conservative assessment of likely project development over the next two years. Additional projects hold permits and have secured or have been offered firm transmission capacity and may proceed with construction if customers are secured.

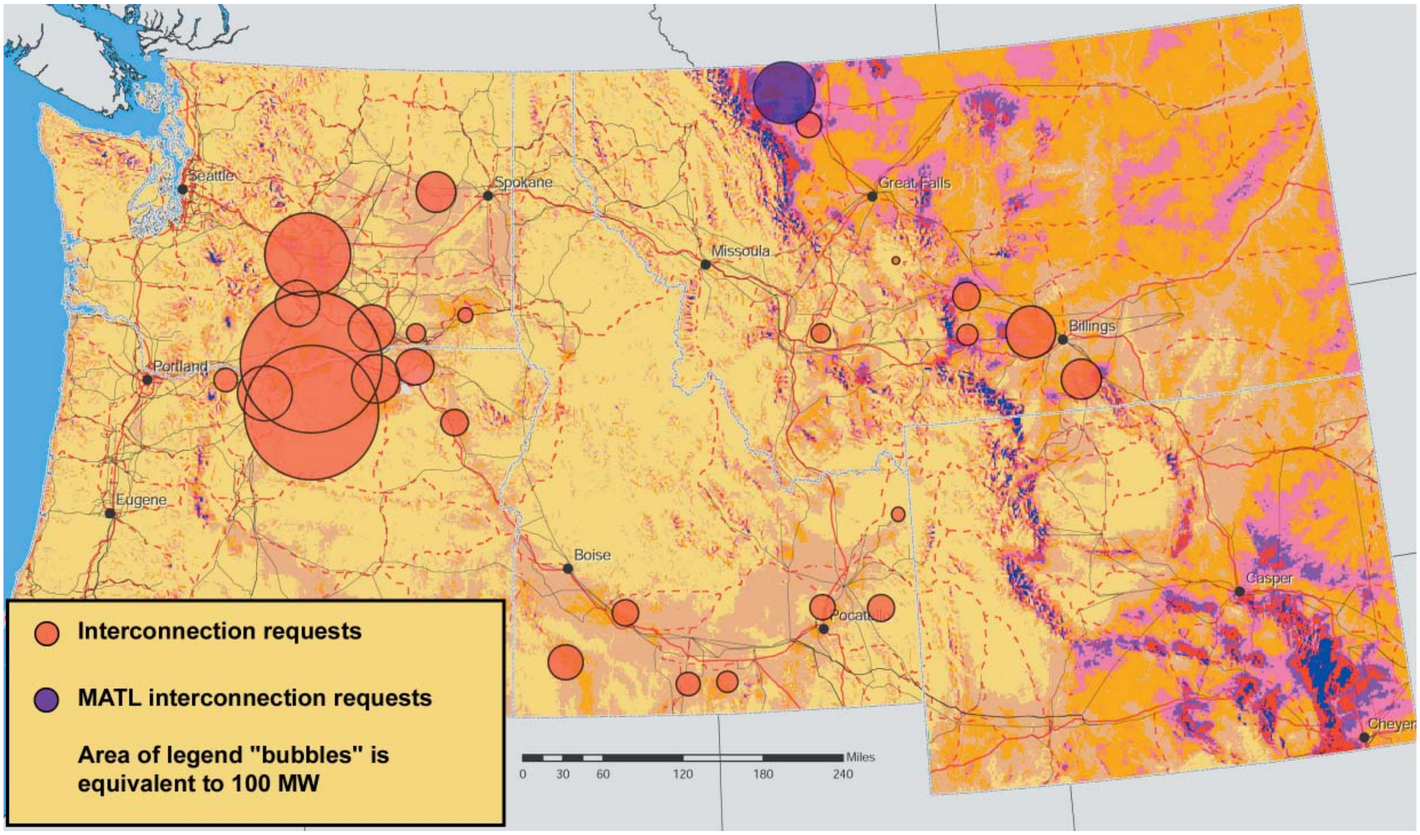


Figure 2: Wind project interconnection requests

Additional development east of the Columbia River Gorge is likely. Shown in Figure 2 are circles depicting the magnitude of active requests to regional transmission providers for interconnection of proposed wind projects. The circles of Figure 2 are at the same scale as the circles of Figure 1, but are county level aggregates, not individual projects[9]. Nearly 9,900 MW is represented – in addition to the capacity depicted in Figure 1. Though few expect a large fraction of this capacity to be developed in the near future, it is evident from Figure 2 that the interest in sites at the east end of the Gorge persists. Nearly 6,200 MW (63 percent) of interconnection requests are for projects within six counties at the eastern end of the Gorge.

While good winds and compatible land use are essential components of a suitable wind project site, transmission has emerged as the key driver of project location in the Northwest. The location of so much proposed wind development east of the Gorge is symptomatic of the availability of transmission to Northwest load centers. Because the northern terminals of the southern interties are within the Lower Columbia area east of the Gorge, California's growing demand for renewable resources, driven by that state's aggressive renewable portfolio standard, is likely to become an increasingly significant driver of wind development in this area. The impact on wind development of possible new transmission lines is also evident in the figure. The blue circle in north-central Montana represents projects that would be serviced by the proposed MATL transmission line north to the Calgary load area.

[9]FERC rules prohibit revealing the name or location beyond the county level of projects requesting interconnection until the interconnection agreement is in place.

Wind energy is not fundamentally different from anything control area operators have to deal with when managing load variability. However, one megawatt of new wind is significantly more variable and less predictable than one megawatt of new load.

The capacity value of wind

The atmospheric drivers of wind have implications for the Northwest during certain weather patterns, especially in the winter months. Periods of extreme low temperatures and high loads tend to occur when the region is affected by large-scale, high-pressure systems. These systems produce very little pressure variation across the region, and hence, an absence of wind. Also, there is recent evidence that a similar phenomenon occurs during extremely high temperatures and loads. The correlation between temperature and the availability of the wind is illustrated in Figure 3, using data from four wind projects in the BPA system. The lowest availability of wind clearly occurs during times of especially high and low temperatures[10].

Since extreme heating and cooling events frequently are 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 these 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 to 10 percent of nameplate capacity. On November 27, 2006, during the peak load hour of a regional cold snap, the combined wind projects of BPA and NorthWestern Energy generated at 3 percent of their nameplate capacity.

Single-hour or daily peak period capability is not the limiting factor for system reliability because of the short-term storage and shaping capability of the Northwest hydroelectric system. The Northwest Resource Adequacy (NWRA) Forum's capacity adequacy metric bases the sustained peaking capacity value of a resource on its average contribution to the system over five sequential, 10-hour peak load days (the 50-hour sustained capacity)[11]. For its pilot capacity standard, the NWRA Forum has assigned a provisional, 15 percent sustained peaking capacity value to wind. The wind fleet performance during peak load events suggests that the 15 percent figure may be too high. As a result, the NWRA Forum has agreed to reassess the capacity contribution of wind.

The fact that wind energy contributes relatively little sustained peaking capacity to the power system means that with or without wind energy, Northwest utilities will need to rely on other capacity resources (thermal, renewable, or demand-side) to meet their peak load requirements. Wind power will be added as a variable and complementary energy resource to a portfolio of firm capacity resources.

The relatively low capacity contribution of wind does not negate the fundamental value proposition of wind energy: it displaces fossil fuels and their associated emissions, and lowers exposure to price volatility and uncertainty.

ACTION 1: By July 2007, the Northwest Resource Adequacy Forum (NWRA Forum) should reassess its 15 percent pilot sustained wind capacity value using currently available data on wind plant operation during periods of peak load. In 2008, the NWRA Forum should further refine the sustained peaking capacity value of wind power using the improved wind resource data set of Action 3 and other available data.

[10] 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 the subsequent phase of this project. Also, current wind turbine technology is capable of higher capacity factors at lower wind speeds than the technology underlying the data of Figure 3.
[11] Individual utility systems with less access to hydro resources may use different approaches to determining the capacity contribution for the wind in their portfolios.

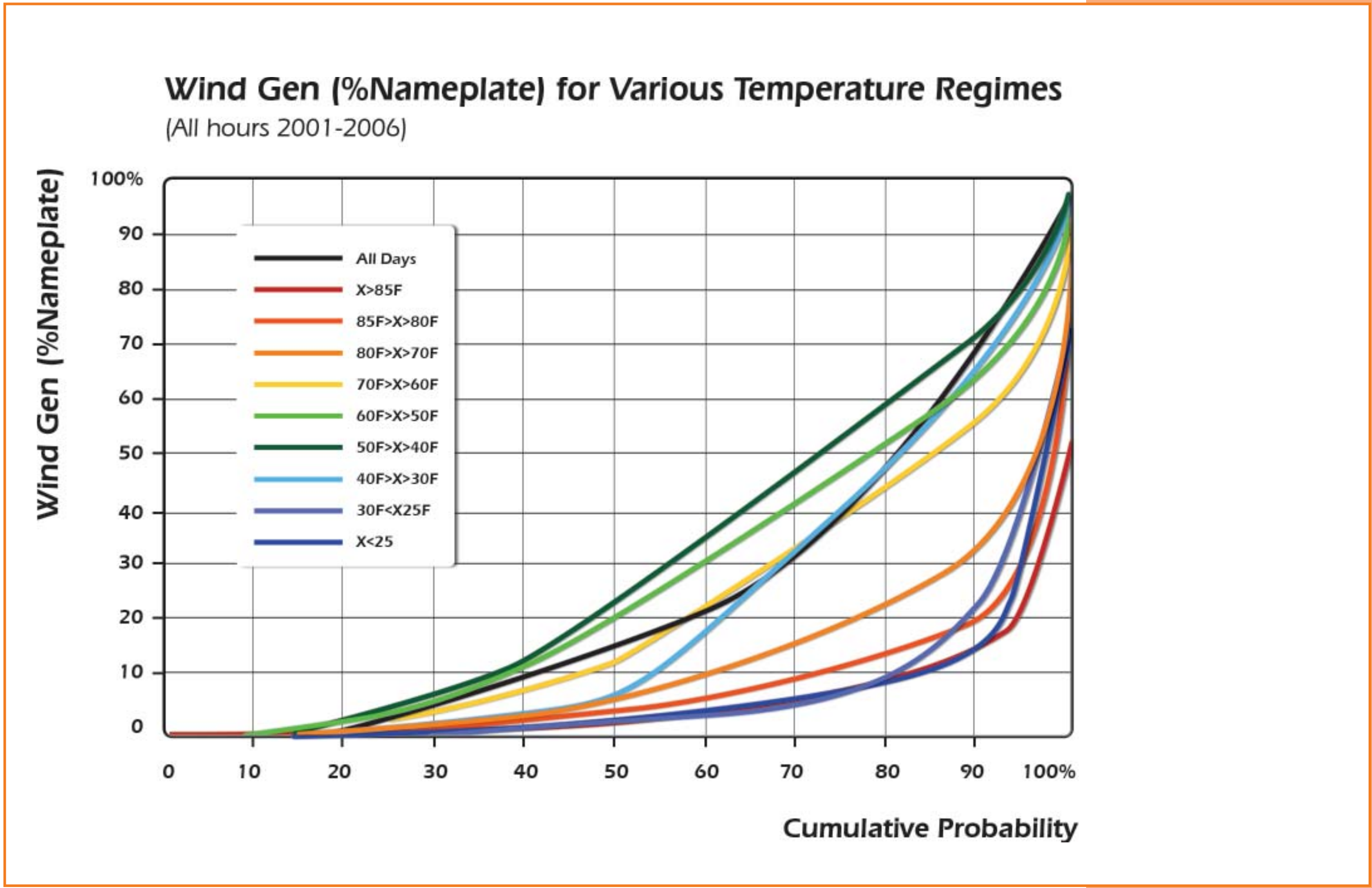


Figure 3: Wind production relative to load center (Portland, Seattle, Spokane) temperature (BPA Projects, 2001-2006)

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

The moment-to-moment and hour-to-hour variability of wind makes it behave much more like negative load than traditional generation. Wind energy is not fundamentally different from anything control area operators have to deal with when managing load variability. However, one megawatt of new wind is significantly more variable and less predictable than one megawatt of new load.

Viewing wind generation as a negative load rather than as a source of generating capacity makes it easier to understand its impact on system operations. All utility systems are designed to manage load variability and forecast error. This variability and uncertainty by itself is substantial; BPA and other control areas regularly deal with load changes of several thousand megawatts during morning and nighttime ramping periods. The systems manage these changes without difficulty under the vast majority of conditions. Given that even the most dispatchable generation technologies have some variability and uncertainty, the objective of control area operations is to manage net system variability and net system uncertainty. When wind energy is added to

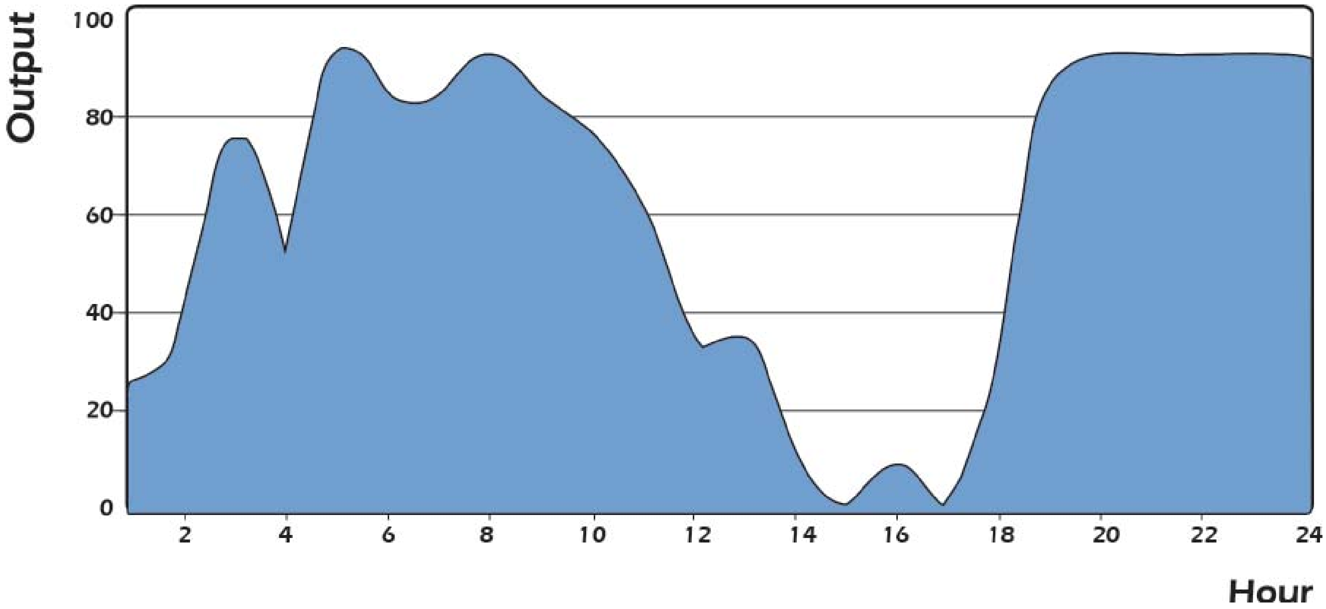


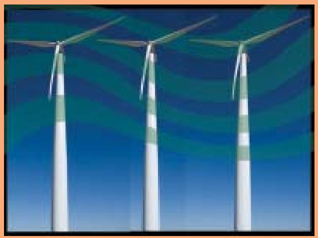
Figure 4: Illustrative diurnal output of a wind plant

the equation, its variability and uncertainty becomes part of this net system variability and uncertainty.

At low wind penetration levels, the amount of variability introduced by a small amount of wind is virtually lost in the larger fluctuations of loads. As the amount of wind increases, the effects of wind variability dominate the effects of load variability and the ranges of net system variability and net system uncertainty increase. This places additional demands for system flexibility across two main time horizons: within-hour (1-60 minute) and hour-to-hour. An example of variability across these horizons is portrayed in Figure 4.

Wind integration 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 in the within-hour time frame. Control areas carry regulating reserves to manage the minute-to-minute changes in their load and resource balance. Northwest control areas 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 types of operating reserves. Other types of operating reserve include contingency reserves for responding to sudden unplanned generation or transmission outages[12].



[12]Under current rules, wind projects are treated like hydro resources from the perspective of contingency reserves.

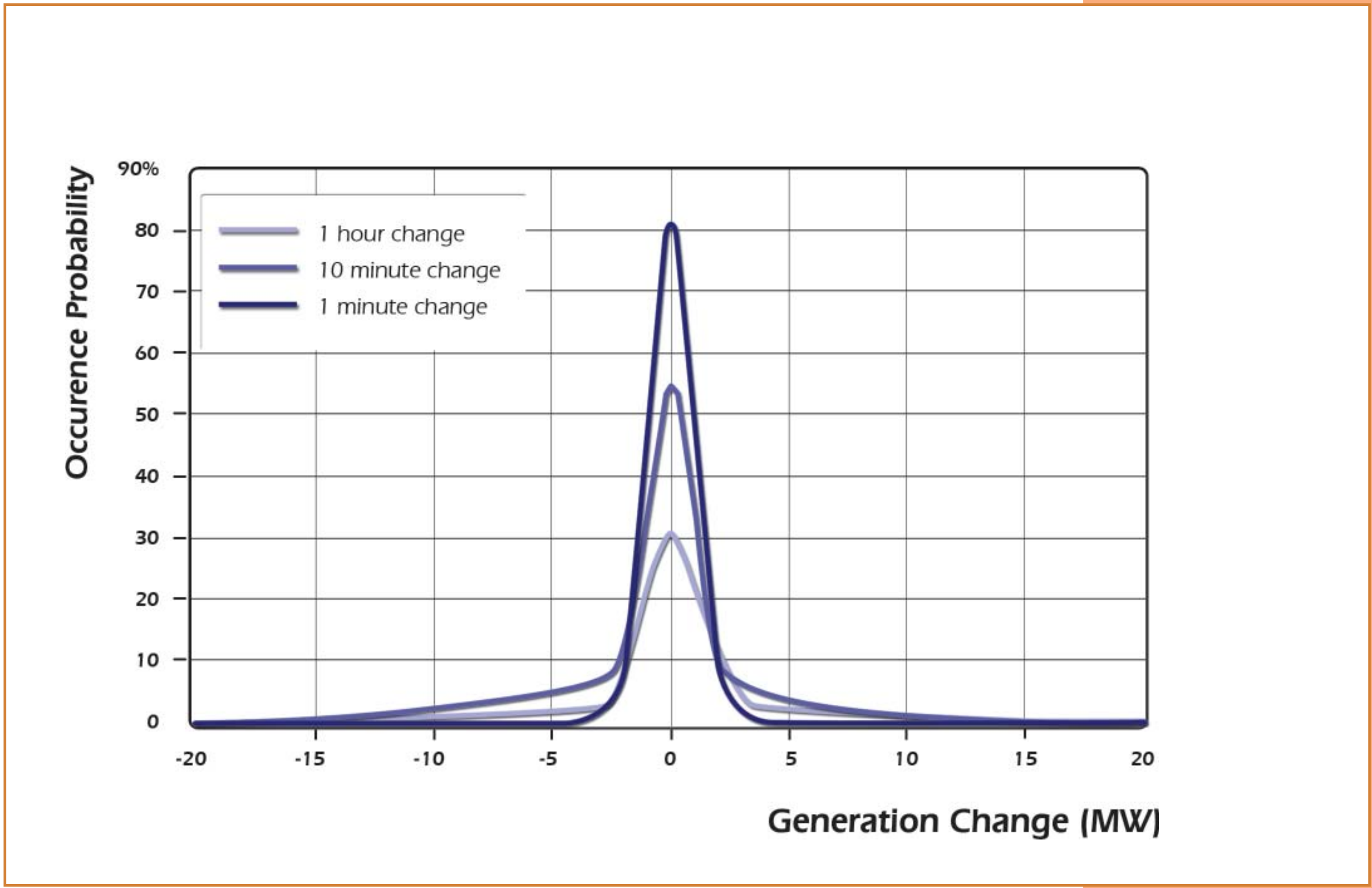


Figure 5: Short-term generation step changes for wind projects in the BPA control area

Figure 5 illustrates the combined within-hour behavior of 208 MW of installed capacity from four wind projects in the BPA system. The figure depicts the probability distribution of wind output changes, as megawatts up or down, over the 1-minute, 10-minute and 60-minute time horizons. As can be seen, for all three series, the variability is clustered around zero with low probabilities of occurrence in the tails of the distributions.

Figure 5 illustrates how step changes increase with the time step considered. Incremental 1-minute regulating reserves necessary to manage wind energy – even for a large wind fleet – are quite small compared to existing requirements. This is because wind project output seldom changes dramatically over very short time intervals, and wind turbine output – even in individual wind projects of medium to large size – is not highly correlated with load across the regulating time frame. Changes in wind turbine output across the load following timeframe (10 to 60 minutes) are larger due to higher correlation between wind projects on that timescale. Changes in wind power output over the load following time horizon are a larger driver of the incremental demand for within-hour reserves than are the changes occurring in the regulation time frame.

Predicting the absolute level of wind over a given hour provides a second challenge to integrating wind energy. Wind forecast errors must be evaluated in combination with the other sources of uncertainty in system operations, especially load forecast errors. BPA evaluated the forecast errors of these same four wind projects from 2001-2006. It found the distribution shown in Figure 6.

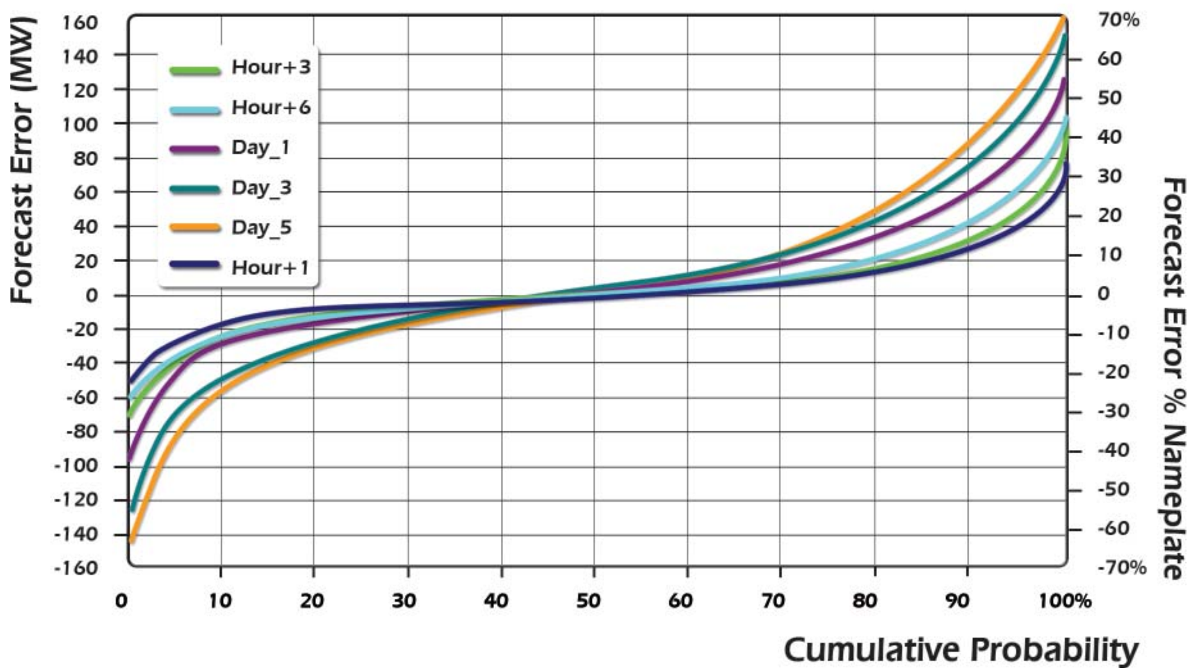
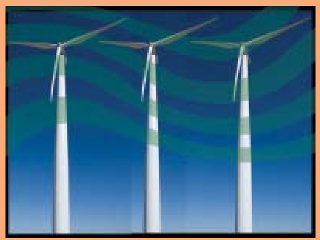


Figure 6: Distribution of forecast errors for BPA wind projects

As shown, the quality of the wind forecasts improves dramatically from five days ahead to one hour ahead. For the one hour ahead forecast, 90 percent of the wind forecast errors vary between minus 10 percent and plus 15 percent. These uncertainties are mitigated partially by combining wind and load forecasting. Good wind forecasting is an essential element of managing wind power and mitigating the costs of wind forecast error.

Northwest system operators must have access to sufficient regulation and load following reserves to meet the incremental variability and uncertainty created by wind. Operators with sufficient system flexibility will be able to secure all or a portion of the incremental operating reserves by changing how they operate their existing fleet of assets. This likely will result in reduced operational efficiency. Examples of this lost efficiency include running units out of economic merit order and placing generating capacity that otherwise would be used for short-term secondary energy marketing on reserve status. Where and if flexibility becomes exhausted, utilities will have to procure flexibility from neighboring control areas, install controls or other equipment to increase the existing system's flexibility, or develop new generating or demand-side resources capable of providing the needed flexibility.

For BPA and other hydro-dependent control areas, one of the most salient examples of running units out of economic merit order involves operating hydro facilities more actively at night to secure additional ramp-down capability. Since the primary economic objective of hydro operations is to conserve



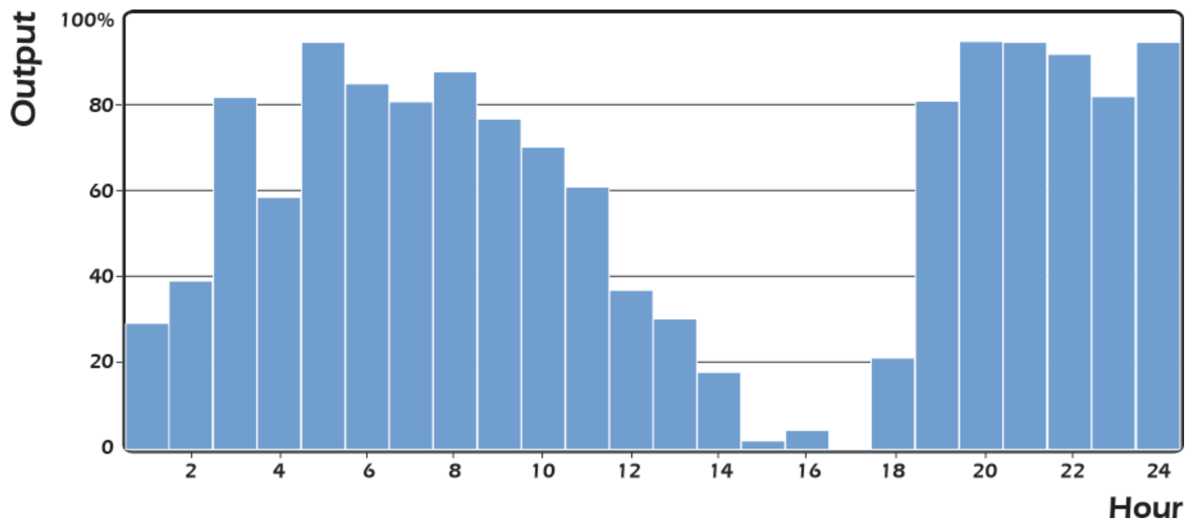


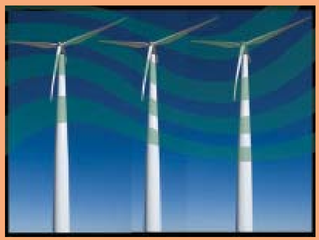
Figure 7: Wind output after within-hour integration by a control area

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. In Section V, this Action Plan discusses the considerable benefits – and periodic challenges – of using hydro resources as the principle source of operating reserves to integrate wind.

Within-hour regulating and load following reserves also ensure that power transfers between control areas are delivered according to hourly schedules. For example, if a wind project located in one control area schedules 100 MW for delivery to another control area, the host control area must use its regulation and load following reserves to ensure that 100 MW of power is actually delivered, even if the wind project deviates substantially from its schedule. In vertically disaggregated utilities operating under the provisions of FERC's Open Access Transmission Tariff (OATT), within-hour operating reserves are supplied by the transmission side of the business.

Managing wind energy in the hour-to-hour time frame

Figure 7 depicts the hour-to-hour shape of wind output after the control area has managed its within-hour variability. These changes in forecasted hour-to-hour output are managed by the power side of the business through the dispatch of generating assets or by making balancing purchases and sales. For larger utilities with sufficient generation flexibility to avoid



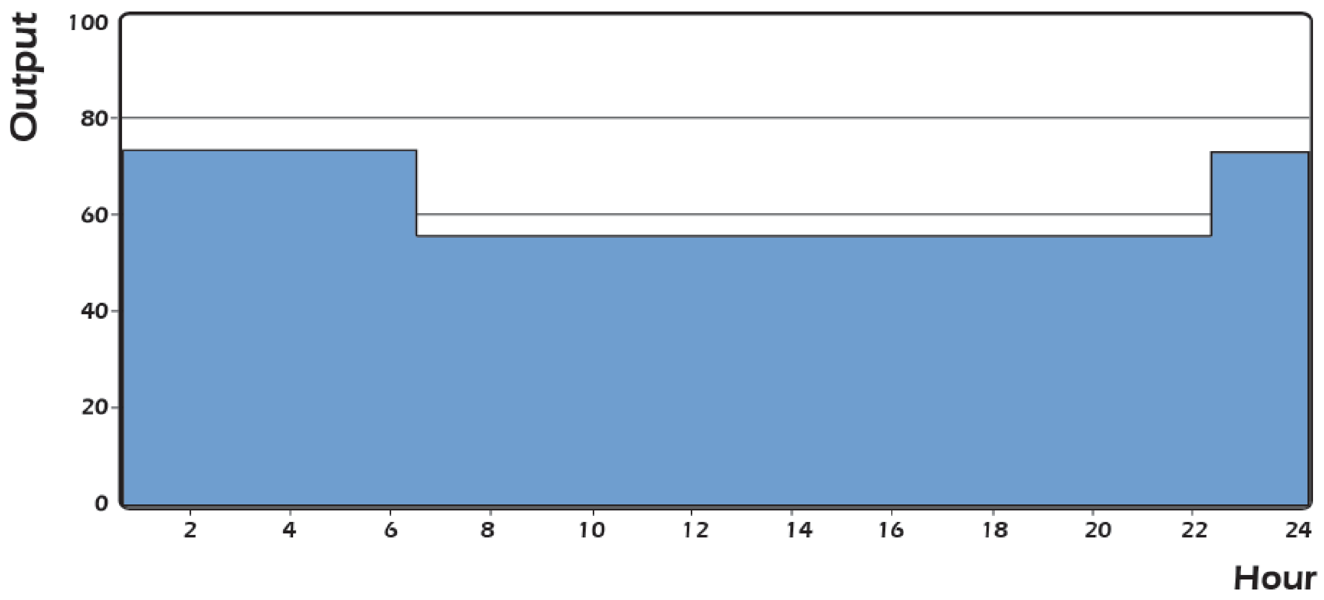


Figure 8: Wind output after purchasing a storage and shaping service

over-dependence on balancing purchases and sales, hour-to-hour changes may have little additional cost impact. However, smaller utilities and wind developers, who must rely more actively on the market to balance the hour-to-hour changes in wind generation (or deviations from day-ahead forecasts), may incur costs associated with market illiquidity and volatility. Some may choose to purchase additional services to help manage this variability, if such services are available. Several of the region's utilities and marketers have developed wind integration services, though few are offering them today. For example, BPA's Storage and Shaping Service (S&S) and Network Wind Integration Service (NWIS) 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 (NWIS). BPA offers neither service today. 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 8 depicts the shape of wind power output of Figure 7 after it has been stored and shaped for redelivery into flat blocks of peak and off-peak energy.

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 typically have not included specific payments for within-hour balancing services that must be simultaneously purchased from the transmission side of the business[13]. The market for shaping

[13]Most but not all transmission providers purchase the generation inputs for their ancillary services from their merchant functions. NorthWestern Energy, one exception, purchases such services from the market.

services is, at present, extremely limited. This is also true of the market for within-hour balancing services. This Action Plan explores the root causes of this lack of market depth, and potential ways to expand the market for these products in Section V.

Wind integration costs are driven by the costs of securing and dispatching incremental operating reserves and managing hour-to-hour changes in wind output

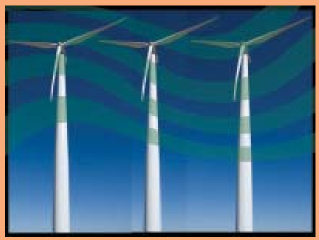
The opportunity costs associated with the operational or marketing changes required to carry additional operating reserves are the chief source of wind integration costs. There may also be additional wear and tear on hydro and other units, as well as efficiency losses resulting from the additional cycling.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

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

As further discussed in Section V, many of the region's investor-owned and public utilities rely primarily on hydroelectric facilities for regulation and load following reserves. With increasing amounts of wind, there will be occasional periods when large, unexpected changes in wind output ("wind ramps") occur during conditions of limited hydro flexibility. This will lead to reliability issues (CPS2 violations) unless the control area operator can restore system balance in other ways. Other means of managing large unexpected changes in wind generation include: marketing the wind power on short notice (which may be very difficult given the Northwest's 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 (if not environmentally constrained), or reducing the output of the wind projects.

If more cost-effective sources of system flexibility have been exhausted, maintaining system reliability during these large wind events can be achieved by limiting wind project ramp rates or output until such time as additional system flexibility becomes available. Preliminary analysis indicates that these are low probability events. Further study of the frequency and magnitude of these events is necessary.

FERC, in Appendix G of its standard Large Generator Interconnection Agreement, requires wind plant operators to secure the capability to transmit data and receive instructions from the control area operator in order to participate in system balancing mechanisms and help protect system reliability. Wind project output control will be implemented through the interconnection agreements between project owners and control area operators. Managing severe wind ramps will require new tools for control area operators. Because limitations on wind output will impact wind project economics, this Action Plan recommends that Northwest control areas work with wind developers, and through a rigorous cost/benefit analysis, seek to achieve the reliability requirements of Appendix G in a mutually satisfactory and cost-effective manner. Beginning in mid-2007, BPA will conduct a public process for implementing its economic and operational framework for active wind output control.



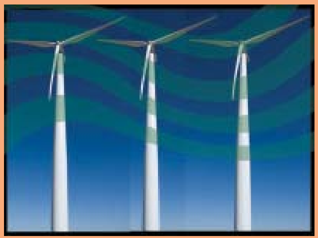
Leaning Juniper Wind Power Plant, Arlington, Oregon. Photo courtesy of PPM Energy.

FERC has also established dynamic performance requirements for wind turbines to help support grid security and stability. As a result, most new Northwest wind projects are using modern turbine designs capable of dynamic performance comparable with that of conventional generation. Dynamic performance is an interconnection wide issue, and is being addressed at the Western Electricity Coordinating Council (WECC) through modeling, performance evaluation and standard setting. It is recommended that Northwest stakeholders continue to support and participate in these activities.

Creating a geographically diverse, low-cost wind fleet

It is widely acknowledged that geographically diversifying wind projects reduces total wind fleet variability, lowers the probability of large ramping events, and improves aggregate wind forecasting accuracy. Lower variability and uncertainty translates directly into lower wind integration costs. Preliminary results of Avista's 2007 wind integration study confirm the benefits of geographical diversification as do a number of studies from other parts of the country including the recently released Minnesota wind integration study[14].

Access to wind sites with higher capacity factors such as those in Montana, and the ability to diversify wind generation patterns, will result in lower busbar and wind integration costs (all else being equal). A one-percent increase in capacity factor can reduce busbar costs by $2.50/MWh. To achieve the economic and operational benefits of geographical diversification, wind projects will need sufficient transmission capacity to move their power to load. The challenge to our region is finding a way to meet the transmission requirements for wind energy at the lowest possible cost to regional ratepayers. The current practice of relying entirely on firm transmission capacity for an energy resource with little firm capacity contribution needs to be revisited. Transmission planning for new wind resources also needs to be conducted in the larger context of regional generation and transmission planning. This Action Plan discusses this issue in greater detail in Section III.



[14] Enernex Corporation. 2006 Minnesota Wind Integration Study. Prepared for the Minnesota Public Utilities Commission, November 2006.

II. Operational capability and costs of integrating wind in the Northwest

This section summarizes the preliminary findings and conclusions of five initial Northwest wind integration studies. Appendix B contains a more detailed discussion of the individual study methodologies.

Overview of studies

The costs of wind integration are driven by the need to secure additional operating flexibility on several timescales to balance fluctuations and uncertainties in wind output. The Technical Work Group reached general agreement on wind integration cost-causation mechanisms given the block hourly day-ahead and real-time market structure currently in place in the Northwest. Three Northwest utilities – Avista, Idaho Power and BPA – have performed new wind integration studies that reflect the unique characteristics of their systems. Previous studies by Puget Sound Energy (2003) and PacifiCorp (2001, 2004) addressed similar cost-causation mechanisms.

The Avista, Idaho Power, Puget and PacifiCorp studies evaluate the costs of integrating wind energy for native load service. They reflect both within-hour and hour-to-hour costs of integrating wind energy. BPA focused initially on within-hour costs to help inform future revisions to ancillary service tariffs and rates that will be needed to address the rapid growth of wind projects interconnecting to the federal system, but serving nonfederal loads. BPA plans to revise its cost estimates and analyze wind impacts on its hour-to-hour operations in 2007.

Cautions and caveats

Preliminary cost estimates from the initial Northwest wind integration studies are cited below. The studies represent a significant step forward in regional understanding of wind integration costs, but it should be carefully noted that the cost figures and methodologies underlying the studies are still the subject of debate among members of the Technical Work Group. Revisions to several of the studies are still under way. All of the utilities reporting results intend to revisit their study methodologies and results as better data and analytical techniques become available.

The cost estimates will eventually be translated into formal rates and/or market prices that may deviate from the numbers cited below. The cost estimates are also based on current system obligations and constraints that are subject to change. Future reductions in system flexibility could result in higher costs. The costs may also come down as a result of ongoing study revisions, greater control area coordination, or other cost-reduction strategies. The most current officially released study results are posted on the Council's Website at **www.nwcouncil.org/energy/Wind** and will be updated on a regular basis.

Since the initial BPA study only addressed within-hour impacts, the BPA integration cost estimates are shown separately and likely represent a low-end estimate of wind integration costs on the BPA system.

Wind penetration levels

There are 1,600 MW of wind energy installed in the Northwest. Table 3 shows the amount of implied wind capacity in each utility control area as a function of increasing wind penetration levels. Of the 16 control areas in the Northwest, only six are represented in this table (including PacifiCorp East and PacifiCorp West). NorthWestern Energy, which has been active in the wind sector and is anticipating continued growth of wind in its control area, is not represented. Portland General Electric

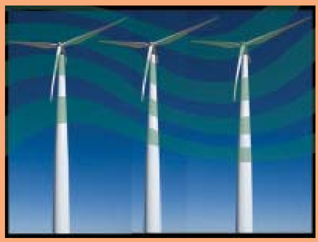


Table 3: Wind capacity as a function of penetration level (percent of peak load) by utility

		Wind Capacity at Different Penetration Levels (MW)					
Utility	Peak Load (MW)	5%	10%	20%	30%	35%	45%
Avista	2,200	110	220	440	660	770	990
Idaho Power	3,100	155	310	620	930	1,085	1,395
Puget Sound Energy	4,650	233	465	930	1,395	1,628	2,093
PacifiCorp	9,400	470	940	1,880	2,820	3,290	4,230
BPA	9,090	455	909	1,818	2,727	3,182	4,091
Total	**28,440**	**1,422**	**2,844**	**5688**	**8,532**	**9,954**	**12,798**

Table 4: Maximum wind penetration levels modeled in initial Northwest studies

Utility	Peak Load (MW)	Penetration (%)	Installed Capacity (MW)
Avista	2,200	30%	660
Idaho Power	3,100	30%	930
Puget Sound Energy	4,650	10%	465
PacifiCorp	9,400	20%	1,880
BPA	9,090	33%	3,000
Total	**28,440**		**6,935**

(PGE), another major investor-owned utility, Seattle City Light, Grant County PUD and other large generating publics are not represented either, yet some of these utilities may integrate additional wind into their control areas.

The five utility studies evaluated different levels of wind penetration on their systems. Puget examined up to 10 percent wind penetration, PacifiCorp evaluated up to 20 percent, Avista and Idaho Power up to 30 percent, and BPA up to 33 percent. Table 4 converts these percentages into installed megawatts.

Based on assumptions about current levels of system flexibility, access to the wholesale marketplace and the occasional use of alternative sources of flexibility including wind output control, the utilities determined that their systems were operationally capable of achieving at least the maximum wind penetration levels modeled in their studies. This equated to 6,935 MW of wind.

The Northwest wind integration studies are based on existing system obligations and resources. Over time, with load growth and other demands on system flexibility, some of the utilities may need to procure additional operating reserves or invest in new generating resources capable of providing the needed flexibility. However, there are no fundamental technical barriers to deploying additional sources of flexibility. This is evidenced in other regions of the country such as Colorado and Texas that depend primarily on gas turbines to provide wind integration services. As a result, based on the initial results in Table 4, and the fact that only six of the 16 Northwest control areas are represented in the results, there do not appear to be any fundamental technical barriers to integrating 6,000 MW of wind in the Northwest. It's a question of cost.

Table 5: Preliminary wind integration costs from initial utility studies ($/MWh of wind generation)[15,16]

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	$2.75	$6.99	$6.65	$8.84
Idaho Power	3,100	Not run	$9.75	$11.72	$16.16
Puget Sound Energy	4,650	$3.73	$4.06	Not run	Not run
PacifiCorp	9,400	$1.86	$3.19	$5.94	Not run

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA	9,090	$1.90	$2.40	$3.70	$4.60

Cost estimates

Table 5 presents the preliminary cost estimates expressed in $/MWh of wind generation by increasing amount of wind penetration (nameplate wind/peak load).

NorthWestern Energy has reported to the Montana Public Service Commission a wind integration cost of $6.75/MWh for the Judith Gap project for 2006. This value is yet to include the expenses for the operation of the Basin Creek gas-fired plant that are solely attributable to wind integration. The wind integration costs for Basin Creek have not been finalized for 2006. The NorthWestern control area has a wind penetration of 8.7 percent and is currently purchasing all of its control area services at market-based rates.

Key findings

Based on Northwest studies and others from around the world, the cost of wind integration is largely dependent on: (1) the size of the control area where such services are procured in relation to the amount of wind being integrated; (2) the geographic diversity[17] of wind sites and resultant generation patterns; (3) the amount of flexibility available to the power system; and (4) access to robust markets for control area services and storage and shaping products.

Table 5 illustrates a general trend of lower wind integration costs with increasing control area size. The Avista numbers also shine light on the benefits of geographical diversification. By virtue of purchasing a more geographically diverse portfolio of wind projects under its 20 percent penetration case relative to its 10 percent case, Avista is able to double the amount of wind in its system while simultaneously lowering its per-megawatt hour costs.

Wind integration costs are also driven by dynamic market variables and the amount of system flexibility available to each utility. For hydro-dependent utilities that provide flexibility from their own resources, wind integration costs are largely a function of the spread between peak and off-peak power prices, and current water supply conditions. For control areas with insufficient flexibility to manage their

. . . there do not appear to be any fundamental technical barriers to integrating 6,000 MW of wind in the Northwest. It's a question of cost.

[15] BPA evaluated the current amount of wind in its system (733 MW) and then evaluated costs at 1,000 MW (11 percent penetration), 2,000 MW (22 percent) and 3,000 MW (33 percent). For ease of comparison, the percentage figures have been rounded down slightly in Tables 5 and 6.
[16] Avista, Idaho Power Co., PacifiCorp and Bonneville Power Administration results are in 2006 dollars. Year dollars of Puget Sound Energy results are not reported
[17] Diversity in this context refers to the extent to which changes in wind output at one wind site are different from the changes at other wind sites.

Table 6: Preliminary wind integration costs from initial utility studies expressed as a percent of wholesale electricity market prices

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	5%	12.7%	12.1%	16.1%
Idaho Power	3,100	Not run	15.5%	18.7%	25.8%
Puget Sound Energy	4,650	6.2%	6.8%	Not run	Not run
PacifiCorp	9,400	3.1%	5.3%	9.9%	Not run

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA	9,090	3.2%	4.0%	6.2%	7.7%

own wind resources, wind integration costs are a function of the market price for control area services and other required shaping products. Absent access to other sources of flexibility, utilities will need to invest in new generating or demand-side resources to secure the needed flexibility.

Several of the studies also found that integration costs were very sensitive to the absolute level of wholesale energy market prices. Where market prices rise or fall by 50 percent from today's levels, integration costs would also be expected to change by a similar percentage. Table 6 expresses the individual utility wind integration costs as a percent of the wholesale price of electricity embedded in each of the studies.

Using Table 6, it is possible to estimate wind integration costs at various levels of wind penetration and market prices, and to normalize the wind integration cost estimates of individual studies that may have been based on different electricity market prices

The Northwest wind integration supply curve

Conceptually, regional wind integration costs can be represented as a supply curve relating cost to the level of installed wind capacity. The incremental costs start out very low, as the amount of variability introduced by a small amount of wind is virtually lost in the larger fluctuations of loads. As the amount of wind increases, the effects of wind variability ultimately dominate, and flexibility needs to be added to the system in direct proportion to the growing wind penetration. Some analysts suggest that there is an upper limit on how high wind integration costs can go based on the cost of gas-fired resources.

Consider a combination of a wind project and a gas turbine, each with the same nameplate capacity. The two projects are operated to meet a fixed, contractual amount equal to their individual nameplate capacity – the wind project offsets the gas resource when the wind blows. For example, a 300 MW wind farm could contract with a 300 MW gas plant to serve a fixed 300 MW contract delivery. When the wind blows, the gas resource backs down.

Operating a gas plant in that way incurs costs due to lower efficiency, increased operating and maintenance costs, possible plant modifications for controls and ramping capability, and potential fuel contracting costs due to the variability and uncertainty of wind. It is reasonable to consider these the wind integration costs. With gas resources relatively

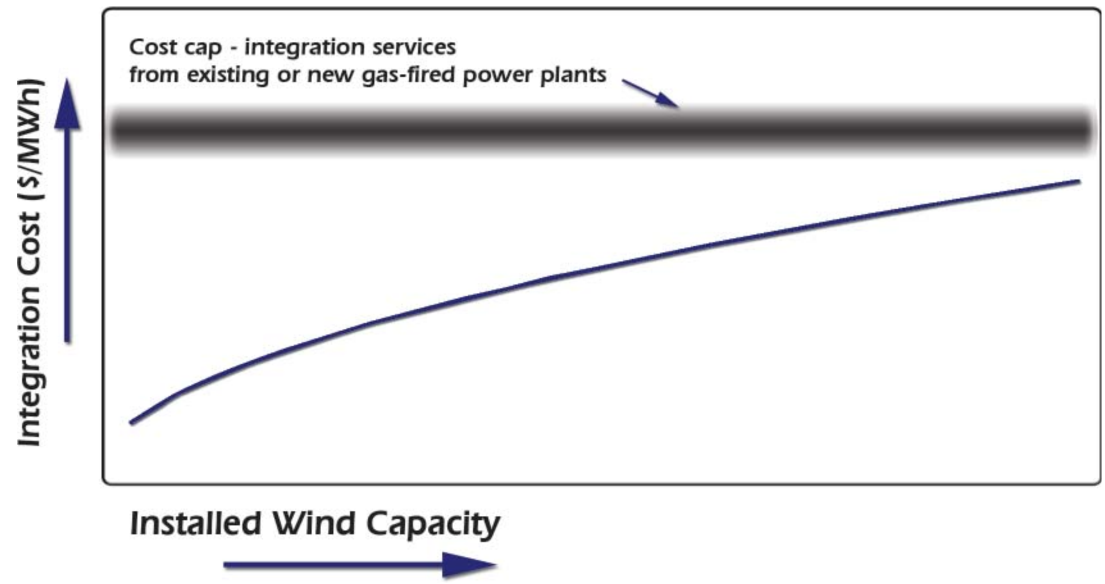


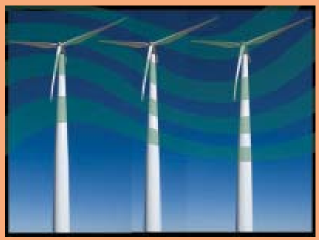
Figure 9: Conceptual Northwest wind integration supply curve

available, this may represent an upper limit on wind integration costs. As discussed in Section V, however, other supply and demand-side technologies may play an increasing role in providing system flexibility over time.

A conceptual wind integration supply curve is represented in Figure 9.

Given differences in the types of costs addressed by the studies, as well as the limited number of Northwest utility studies represented in this report, it is not yet appropriate to collapse the individual utility supply curves reported above into a single supply curve for the region. Over the coming year, a better understanding of the composite Northwest wind integration supply curve should emerge as the utilities participating in the Northwest Wind Integration Forum continue to refine their study methodologies and estimates of the wind integration costs using a robust stakeholder input process. They also will estimate the potential for shifting the supply curve to the right through control area cooperation, more active markets for control area services and other strategies to reduce costs or extend integration capability.

ACTION 2: Utilities participating in the Northwest Wind Integration Forum should continue to refine their study methodologies and estimates of wind integration costs using a robust stakeholder input process. They should also estimate the potential for reducing the cost and extending the supply of wind integration services through control area cooperation, more active markets for within-hour balancing services and other strategies.



Addressing data limitations

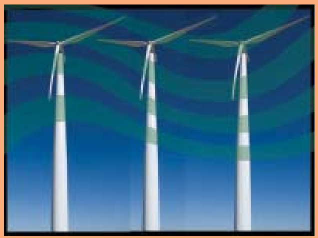
The Northwest does not possess wind data adequate to quantify the benefits of cooperative operational strategies, to evaluate the benefits of geographical diversification, to inform transmission planning efforts, and to fully evaluate the capacity value of wind. As part of the Northwest Wind Integration Forum, the Steering Committee has agreed to fund the development of a better data set. Appendix C provides technical requirements and a cost estimate for a Northwest chronological wind data set.

ACTION 3: The Northwest Wind Integration Forum should contract for the development of a high-resolution chronological wind resource data set for the Pacific Northwest. The data set should be available by December 2007.

Summary of wind integration studies from other regions

More than 200 wind integration studies have been performed over the past decade[18]. Most come from utility systems outside of the United States, and many do not benefit from current state-of-the-art methodologies and datasets. However, a number of recent studies have used methodologies based on best practices. Table 7 summarizes results from several recent wind integration studies outside of the Northwest.

While informative, care must be taken when making comparisons between these studies and wind integration costs in the Northwest.



This is because the studies come from regions with different:

- Market structures
- Wind penetration levels
- Wholesale market prices
- Wind generation resource characteristics
- Nonwind resource mixes
- Interconnections to other systems

Market structure

Market structures vary considerably across the United States. In the Northwest, there are three bilateral wholesale energy markets: a forward market (balance of month to one year or more), a day-ahead market, and an hourly "real time" market. The day-ahead and hourly "real time" markets trade in 60-minute blocks. There are no formal, structured markets for within-hour regulation or load following. The Northwest has 16 individual control areas, several of limited size.

Several regions of the country have much larger control areas and administer shorter-term markets for ancillary services. As demonstrated in Table 5, larger control areas spread the variability and uncertainty of wind over a larger portfolio of loads and resources, which results in cost savings relative to smaller control areas. Preliminary analysis by Avista indicates that shorter market timeframes can reduce wind integration costs by 20 percent to 60 percent, due in large part to the reduced wind forecast errors associated with shorter-term scheduling windows.

Studies from other parts of the country reflect varying degrees of access to shorter-term markets. The recent EnerNex-Minnesota study was modeled in a five-minute market with access to the within-hour balancing resources of the entire Midwest Independent System Operator (MISO) footprint. Adjusting for this major difference in market structure could significantly increase estimated costs for Minnesota. A full discussion of the pros and cons of various mar-

[18]The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity 16network, March 2006. **www.ukerc.ac.uk/component/option,com_docman/task,doc_download/gid,550/**

ket structures is well beyond the scope of this document. However, in Section V, there is an exploration of ways to capture some of the benefits of larger control areas and ancillary services markets, without changes to the market structure of the Northwest.

Table 7: Selected extra-regional wind integration study results

Study Year	Study	Penetration (%)	Spot Market (minutes)	Integration Cost ($MW)
2003	Xcel-UWIG	4	N/A	1.85
2003	WE Energies	4		1.90
2003	WE Energies	29		2.92
2004	Xcel-MNDOC	15	N/A	4.60
2004	VTT-Scandinavia	10*		1.29***
2004	VTT-Scandinavia	20*		2.58***
2006	Xcel-PSCo	10	N/A	3.72
2006	Xcel-PSCo	15	N/A	4.97
2006	Enernex-MN	2**	5	2.11
2006	Enernex-MN	3**	5	4.41

* Penetration based on MWh generation / MWh load
** Penetration based on MSO footprint
*** Euros / MWh converted to dollars @ 1.29 Euro / dollar

Wind penetration level

Generally, wind integration costs rise as more wind is interconnected within a control area. One should not expect costs from one system study with a penetration rate of 5 percent to be similar to a study with a 20 percent penetration rate.

Wholesale market prices

Northwest integration studies confirm that wind integration costs are highly correlated with the absolute price of the wholesale marketplace. Higher market prices tend to lead to higher integration costs.

Wind generation resource characteristics

Wind patterns differ across the country. Wind patterns in one geographic location can be very volatile, while at another location wind speed variations are less pronounced. Some regions find that their various wind sites are not highly correlated, thereby reducing incremental operating reserve requirements. Improved wind data will help us better understand the extent of diversity in wind regimes in the Northwest.

Nonwind resource mix

Resources available to integrate wind energy affect wind integration costs. Most regions in the U.S. use thermal plants to integrate wind. Some systems have a "deep" stack of flexible resources to provide balancing capacity, while others do not.

The Northwest benefits from a large fleet of relatively flexible hydroelectric projects, though the amount of flexibility varies across its 16 control areas.

Interconnections to other systems

The nature and extent of interconnections with other systems affects study results. The EnerNex-Minnesota study assumed up to a 25 percent wind penetration level for the state of Minnesota. However, the state has strong interconnections with MISO and relies heavily on having non-Minnesota resources within MISO provide incremental balancing capacity for its proposed wind regime. The purported 25 percent penetration, when considering the MISO footprint, actually equates to a penetration level below 5 percent[19].

[19]The Minnesota study assumed 5,700 MW of wind in 2020 to arrive at a 25 percent penetration level, whereas MISO has a resource mix today of about 135,000 MW and would grow to approximately 180,000 MW by 2020 assuming a 2 percent annual growth rate.

. . . there is insufficient Available Transmission Capacity (ATC) to serve the full amount of wind power called for in the Council's Fifth Power Plan.

III. Transmission requirements for integrating 6,000 megawatts of wind

Wind project development in the Northwest generally has followed conventional practice, whereby long-term firm transmission capacity is secured for the full installed capacity of a generating project. Although firm transmission contracts have been awarded to many of the wind projects expected to come online before 2009, there is insufficient Available Transmission Capacity (ATC) to serve the full amount of wind power called for in the Council's Fifth Power Plan. The lack of incremental ATC is becoming acute east of the Columbia River Gorge, where hundreds of megawatts of wind generation are under construction, and thousands of additional megawatts are proposed (see Figures 1 and 2). Montana and other parts of the region are facing similar transmission limitations.

Utilities historically have procured long-term firm transmission for the full output of their generation facilities to ensure energy delivery during times of system peak. Moreover, transmission costs, when spread over the output of higher capacity factor resources, are low when compared to the busbar cost of the resource itself.

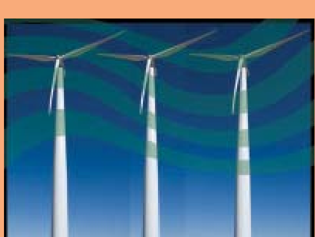
Since wind is primarily an energy resource that makes relatively little contribution to meeting peak loads, utilities may significantly discount wind capacity and not count on it for reliability purposes. If guaranteed delivery in all situations is not needed for reliability, then providing firm transmission for the full installed capacity of a wind plant (or group of wind projects) is both unnecessary and economically inefficient. Moreover, with wind's relatively low capacity factor, firm transmission may double or triple the transmission cost of wind energy compared to a higher capacity factor resource. A more economically efficient approach would be to provide a mix of firm, nonfirm, or conditional firm transmission service that seeks a balance between the marginal cost of transmission capacity and the marginal value of delivered wind energy. This approach will lead to better use of the transmission grid and lower delivered wind energy costs without compromising system reliability.

This new transmission model will result in a mix of transmission products and selective transmission investment. New data and analytical tools will be needed to identify, characterize and evaluate alternatives, seeking the optimal balance between transmission investment and energy delivery. A reallocation of risk and compensation between wind project owners and utilities purchasing wind power may be needed to ensure that project owners are able to obtain financing. Creativity and regulatory support will be needed to bring this about. Despite the complexity of issues that must be resolved, the potential benefits of a new approach are compelling. Hence the following actions:

ACTION 4: By September 2007, the Northwest Transmission Assessment Committee (NTAC) should propose a formal technical transmission planning methodology for regional wind development. This methodology should identify the data requirements and capacity and energy planning tools needed to identify the optimal level of transmission investment needed to efficiently serve future wind development.

ACTION 5: By the end of 2007, Columbia Grid and the Northern Tier Transmission Group, working with NTAC should convene a joint session to begin applying the transmission planning methodology for regional wind called for in Action 4.

ACTION 6: By the end of 2007, the four state regulatory commissions should review and commence to amend as necessary, regulatory policies to remove barriers to more efficient use of transmission for wind and



other renewable resource development. To the extent feasible, policies should be consistent across states.

In order to make more efficient use of the transmission system, mechanisms are needed to ensure that unused firm transmission rights can be transferred between users with sufficient advance notice to facilitate greater system utilization. More active reassignments of transmission can also promote voluntary economic redispatch during periods of transmission congestion that can help manage the risks associated with conditional firm and nonfirm transmission service. A pilot voluntary economic redispatch program should be developed and tested with the initial objective of using existing West of McNary transmission as effectively as possible.

ACTION 7: BPA should continue development of mechanisms to promote greater utilization of the transmission system, including more active reassignments of firm transmission rights, a conditional firm transmission product, and voluntary, multiparty economic redispatch mechanisms. BPA should report the results of these efforts to the Northwest Wind Integration Forum so that other transmission providers might benefit from this experience. The program, if successful, can be applied to integrating wind power from other transmission-constrained wind resource areas such as Montana.

A number of factors, including load growth, conventional generating resource development and retirements, and the growth of wind energy are expected to eventually require reinforcement of the West of McNary/West of Slatt Corridor, the I-5 Corridor south of the Paul Substation, and possibly the Cross-Cascades North and South Corridors (Figure 10). The new transmission model called for above will require resolution of numerous technical and institutional issues. Success is not certain and may require several years. As a hedge against failure, and to prepare for the inevitable need for physical network reinforcements, engineering and economic assessments of potentially needed reinforcements should continue. These studies should incorporate new planning and analytical techniques as they are developed. 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, coupled with current efforts to upgrade the Montana 500kV system, will improve access to higher-quality wind resource areas lying farther east. The increased geographical diversity of projects may reduce the probability of extreme ramping events, improve aggregate wind forecasting accuracy, and reduce the demand for operating reserves to integrate wind. The reinforcements will also improve operating margins on the transmission system as a whole.

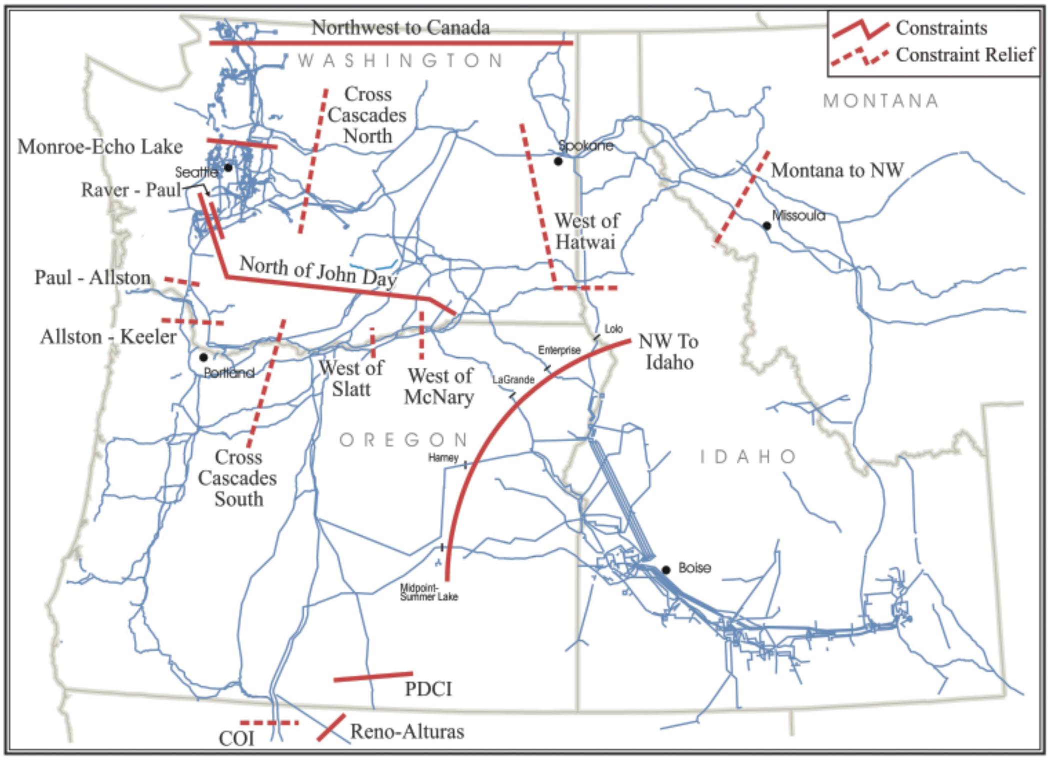


Figure 10: Major transmission path constraints in the Northwest

The financing model 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.

Load growth and conventional generating resource development west of the Cascades is increasing transmission congestion in the I-5 Corridor, particularly south of Paul Substation. Loop flow from wind development east of the Cascades will exacerbate the problem. The need for additional Cross Cascades North and South transmission may be accelerated if dispatchable west side resources are turned down in response to wind availability during peak load periods.

While this Action Plan does not advocate an immediate decision to proceed with construction, the urgency of these problems suggests that BPA should continue with measured steps to prepare for the eventual construction of these reinforcements. This will involve completion of plans of service for the three reinforcements, with priority given to the I-5 Corridor and West of McNary projects, and an assessment of the business case for each. Environmental assessment and other preparations such as permitting and land acquisition would follow favorable business case findings to secure at least the option to build the lines. The new transmission model called for above should be incorporated into these planning efforts, as available.

ACTION 8: By the end of 2008, BPA should work with regional stakeholders to complete plans of service for the proposed West of McNary Phase 1 and West of McNary Phase 2, the I-5 Corridor, and Cross-Cascades North and South transmission reinforcements with priority given to the I-5 Corridor and West of McNary projects. To the extent available, the plans of service should identify preferred upgrades using the capacity and energy transmission planning tools called for in Actions 4 and 5. The plans should include the estimated cost and the amount of commercially viable ATC for each upgrade. Upon completion, the plans and business cases should be reviewed by BPA's Infrastructure Review Committee.

Construction of any of these reinforcements will require a financing model for projects that, like these, are largely driven by development of new resources, as opposed to meeting reliability requirements for load service from existing resources with firm transmission rights. The financing model 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. Moreover, lead times for transmission reinforcement and expansion are much longer than for wind project development.

This Action Plan recommends that BPA continue its development of a generally applicable approach for financing and recovering the costs of partly or wholly market-driven transmission reinforcements and expansions, using the West of McNary project as a prototype. Ideally, the approach would be also be applicable to renewable trunk line transmission primarily intended to serve multiple renewable resource projects located within a common resource area.

ACTION 9: By the end of 2007, BPA should work with regional stakeholders to develop a generally applicable model for financing market-driven reinforcements and expansions of its transmission system using the proposed West of McNary project as a prototype application.

Finally, additional transmission system upgrades and expansions may be desirable over the longer-term to channel wind development to other prime wind resource areas. NTAC should continue to support ongoing studies of the feasibility and cost of extending transmission capacity to high-quality, wind resource areas in Montana and elsewhere that offer geographic diversity, better capacity factors and better coincidence to loads. Investments by BPA and other Northwest transmission providers may be justified.

ACTION 10: By July 2008, using the analytical tools of Action 4 and building on the results of the Rocky Mountain Area Transmission Study (RMATS), NTAC should work with Columbia Grid, NTTG, wind developers and other interested parties to evaluate approaches to delivering wind energy from Montana such as an upgrade of Montana's 500kV system and evaluate opportunities to deliver wind energy from other isolated wind resource areas.

Control areas do not have tariff provisions or rates to charge generators or any individual entities (loads or generators) for the variability they may place on the system.

[19] Regulation costs are allocated to loads based upon their energy consumption or demand, not based upon their variability.

When a wind project interconnects into one control area, but serves the loads of another control area, the loads within the host control area still bear the costs of any additional operating reserves necessary to integrate the wind project.

IV. Wind integration cost recovery

The emergence of wind energy as a significant resource on the Northwest transmission grid raises new cost recovery and allocation issues. Historically, most of the variability in control area operations has been associated with loads, since the output of most conventional generating resources varies little across the course of a scheduling hour except to meet variations in load. When the Federal Energy Regulatory Commission (FERC) developed its Open Access Transmission Tariff (OATT), it created provisions that allocate the costs of regulating reserves (operating reserves) only to the loads within each control area. Neither the FERC Tariff, nor any filed tariffs, allocate regulation costs to individual loads based upon their individual contributions to control area regulation requirements[19]. As a result, control areas do not have tariff provisions or rates to charge generators or any individual entities (loads or generators) for the variability they may place on the system.

As discussed in previous sections of this report, the variability and uncertainty of wind energy increases the demand for operating reserves required to maintain control area reliability. Yet because of the tariff and rate design issues referenced above, loads currently pay for the costs of additional operating reserves required to integrate wind. If a utility is purchasing the output of a wind project for its own native load service, this may not require any changes to the utility's tariff or rate structure, as long as the costs can be appropriately quantified and recovered, although there may be allocation issues among classes of customers.

However, when a wind project interconnects into one control area, but serves the loads of another control area, the loads within the host control area still bear the costs of any additional operating reserves necessary to integrate the wind project. In some cases, agreements such as dynamic scheduling have been negotiated between the host control area and the control area served by the wind plant. These permit the costs of regulation and load following to be born by customers in the control area served by the wind plant. However, absent such arrangements, current tariffs and rate structures do not ensure that entities creating the demand for additional operating reserves are the ones paying for the services.

Although cost recovery and allocation is a threshold issue for each control area, some will likely choose to revise their tariff and rate schedules to better align costs and benefits and protect the economic interests and statutory rights of their native load customers. At the same time, there should be a defensible basis for determining any additional within-hour balancing requirements resulting from interconnected wind resources. Several participants in this project have emphasized that any such tariff or rate changes should be accomplished in a fashion that is consistent with principles of cost causation. Moreover, there is no consensus about the point at which these costs warrant developing a new tariff, and how that tariff should be designed and applied. Given the large number of control areas in the Northwest, there is no single answer to these questions.

For BPA, this threshold has clearly been reached. By the end of 2007, there may be 1,500 MW of wind in the BPA control area, much of it serving nonfederal loads. As a result, in 2007, BPA expects to revise its approach to recovering and allocating wind integration costs. Customers and other stakeholders will have an opportunity to provide input through formal rate case proceedings. Sales of wind integration services will not compromise BPA's statutory obligations to its requirements customers.

V. Regional efforts to reduce integration costs

Wind integration costs are a function of the supply, demand and resulting market prices for system flexibility. They can therefore be minimized by reducing the demand for system flexibility from wind energy projects and by identifying least-cost options for supplying the needed system flexibility. Some of the wind integration studies summarized in this report identified the potential for considerable cost savings through regional actions on both the demand-side and supply-side of the flexibility equation.

A regional wind forecasting network

Wind integration studies performed in the Northwest and in other regions have concluded that wind integration costs are highly sensitive to wind forecast accuracy. Wind forecasting technology and techniques to integrate forecasts into power system operations continue to improve. A regional wind forecasting network using multiple monitoring stations may produce better wind forecasts for a consolidated group of wind projects, leading to lower integration costs for individual projects. The Northwest Wind Integration Forum should evaluate the potential costs and benefits of a regional wind forecasting network and develop an implementation plan if the net benefit exceeds the cost.

ACTION 11: By July 2008, the Northwest Wind Integration Forum should evaluate the potential costs and benefits of a regional wind forecasting network and develop an implementation plan in the event of a positive assessment.

Control area cooperation and expanded markets for flexibility services

Many regional investor-owned and public utilities rely primarily on hydroelectric facilities for regulation and load following reserves. Because hydro resources are fast, flexible and do not consume fossil fuels, they are in many ways ideal economic and environmental sources of flexibility to manage the variability of wind energy. However, they are subject to daily, seasonal and nonpower constraints, as well as increasing load obligations.

For example, during the graveyard hours it could be more cost-effective and environmentally beneficial to back down thermal resources in the event of a system imbalance, than it is to carry downward regulating reserves on hydro projects. As more wind is developed in the region, it will be increasingly beneficial to access the sub-hourly maneuverability of other generating resources in the system. Demand management strategies can also provide system flexibility and should be further explored.

ACE Diversity Interchange (ADI)

The Northwest's 16 separate control areas each are responsible for balancing their own loads and resources. Aggregating wind projects into larger control areas can reduce the amount of balancing capacity needed to integrate wind by affecting both the diversity of the wind generation and relative penetration levels. To date, control area cooperation, rather than control area consolidation has been the rule in the Northwest. Through the Northwest Power Pool, control areas share responsibility for contingency reserves and thereby reduce the overall contingency reserve requirement. Another

method of control area cooperation, known as Area Control Error Diversity Interchange (ADI), is under development by the Northwest Power Pool and being expedited on a pilot basis by several Northwest utilities. Through ADI, participating utilities will share Area Control Error (ACE), which may reduce the amount of regulating reserves each of the individual utilities must carry. Though the incremental demand for regulating reserves from wind energy is quite small, if successful, ADI may take a small bite out of the costs of wind integration as well.

The participating utilities have demonstrated an admirable spirit of cooperation and dedication to solving the technical issues associated with ACE Diversity Interchange. To create greater awareness of this initiative, in July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

ACTION 12: By July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

Expanded markets for flexibility services

Lessons learned from the ACE Diversity initiative may help expand the availability of other control area balancing services that can effectively pool system flexibility beyond the minute-to-minute time horizon of regulation. This is an important objective. As discussed in Section I, the variability of wind (and control area operations in general) is larger across the 10-minute to 60-minute time horizon than it is across the regulation time horizon. Wind variability in this timeframe is responsible for a majority of wind integration costs and therefore represents the greatest area for potential cost savings.

Services designed to provide additional flexibility across the within-hour time horizon 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.

Through the provision of Supplemental AGC, one entity (control area operator or independent power producer) sells a contractually defined amount of generation flexibility (either unidirectional or bidirectional) to assist a control area in managing its within-hour system variability. Dynamic Scheduling effectively moves the output of a load or generating resource from one control area to another. Other products, such as storage and shaping services, can help manage hour-to-hour wind variability.

The market for control area services and storage and shaping products is very limited. NorthWestern Energy knows this from direct experience. In an effort to purchase additional control area services to manage the 135 MW Judith Gap wind project, NorthWestern has run several solicitation processes and found a very small number of sellers. In 2005, BPA placed a moratorium on the sale of its wind integration services, and Grant County PUD is not offering storage and shaping services to new customers.

The Technical Work Group explored the root causes of the limited activity in the market for flexibility services, and identified several important barriers:

1) There are no formal markets or standard product descriptions for wind integration services;

2) Supplemental AGC and Dynamic Scheduling products require firm transmission – sometimes in both directions – which add significantly to the costs of balancing services;

3) 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 while reliably managing the grid;

4) Responsibility for developing and offering flexibility products often lies with the merchant (marketing) functions of the utilities. Marketing entities might not have the necessary product understanding, risk appetite or pricing capability to develop and offer these services;

5) Some utilities may be unwilling to sell flexibility from their systems because they are concerned that they will need the flexibility for their own future 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; and

6) Biological requirements and other periodic system constraints limit contract lengths and require some utilities to require call-back provisions on any marketed flexibility.

These barriers present a timely and important challenge, because the potential benefits of robust markets for these services are numerous. A more robust marketplace for flexibility services would:

1) Leverage the daily and seasonal differences in system flexibility among the region's utilities, and allow utilities to access a supply of lower-cost flexibility when their own systems are facing constraints;

2) 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;

3) Allow more control areas to integrate more wind, thus expanding the geographical diversity of the region's wind fleet;

4) Provide risk management tools to wind developers who are active participants in the wholesale marketplace;

5) Allow independent power producers to generate additional income by monetizing the flexibility characteristics of their assets;

6) Create price signals for innovative demand management strategies;

7) Further reduce the probability of having to limit wind generation output during periods of hydro constraints; and

8) Access some of the benefits of shorter-term markets without fundamental changes to the existing Northwest market structure.

Standardized bilateral markets for flexibility services should lower wind integration costs and could be developed as an extension of the region's current wholesale power markets. For example, a hydro-dependent utility facing nighttime operating constraints could purchase a block of off-peak Supplemental AGC from one thermal-based utility, while simultaneously selling a block of peak hour AGC to another. These services could trade in hourly, daily, monthly and seasonal blocks under standard commercial terms and conditions – without departing from the basic market structure in the Northwest.

To achieve these objectives, multiple regional parties with access to regulation, load following and shaping resources will have to participate actively in the marketplace for flexibility services. For some, expanded markets for such services will represent a long-awaited opportunity. For others, it will require a change in business strategy from an almost exclusive focus on energy marketing to more active participation in the capacity marketplace. With appropriate risk management policies and commercial terms and conditions, such a strategy has the potential to increase wholesale revenues. This topic will be the subject of

A more robust marketplace for flexibility services would allow more control areas to integrate more wind, thus expanding the geographical diversity of the region's wind fleet.

rigorous follow-on discussion by the Northwest Wind Integration Forum.

ACTION 13: By the end of 2007, the Northwest Wind Integration Forum should systematically address the transmission, scheduling, product design, demand management, regulatory, contractual and cost-recovery barriers to expanding the market for flexibility products and services. As part of this process, BPA will explore and report on the feasibility of expediting relief from dynamic scheduling limits on interties to other control areas.

The future of system flexibility in a carbon-constrained world

Since the Council released its Fifth Power Plan, issues surrounding the problems of greenhouse gas and related climate change have gained considerable attention. During the time this Action Plan was being prepared, new and potentially far-reaching legislation has been introduced both nationally and at the state level within the region. In some cases, such as the passage of Initiative I-937 in Washington and the proposed "25 percent by 2025" renewables requirement in Oregon, measures may push wind development in excess of what the Council called for in its Fifth Power Plan. In other cases, such as the Washington Governor's Executive Order 07-02, these proposals call for the reduction of greenhouse gas emissions from historic levels, and may create limitations for the use of thermal resources to integrate wind.

In a carbon-constrained environment, the discussion over maintaining or enhancing hydro system flexibility is not limited to its historic scope, or one that can simply be reduced to a willingness to pay. Rather, it will become a discussion that also involves trade-offs between potential fish impacts and the ability to provide real reductions in greenhouse gas emissions – through the ability of wind to displace thermal resource generation and associated emissions to the maximum extent possible. While that work is beyond the current scope of this effort, this group believes that this is a dialogue that must commence within the region.

In recognition of the potential for wind power integration to adversely impact fish operations, the Council, in Action GEN-9 of its Fifth Power Plan, calls for an assessment of the effects of "shaping" 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. Accomplishment of Action GEN-9 will enable further analysis of environmental tradeoffs between maintained or enhanced hydro system flexibility and potential fish impacts compared to increased reliance upon gas generation and its associated environmental and regulatory impacts related to greenhouse gas emissions. The Council should report its findings with respect to GEN-9 to the Northwest Wind Integration Forum, which may chose to pursue further analysis.

In addition to this analysis, this Action Plan recommends evaluating the potential applications for other existing and emerging technologies including pumped hydro, compressed air storage, batteries and demand management. A more detailed, preliminary discussion of several of these technologies and their applications is provided in Appendix D.

ACTION 14: By the end of 2008, the Northwest Wind Integration Forum should sponsor an effort to further characterize options for augmenting system flexibility. These should include demand-side options, power generation technologies and storage and fuel synthesis technologies. The Northwest Power and Conservation Council should complete Action GEN-9 of the Fifth Power

Plan to improve understanding of the tradeoffs between competing uses of system flexibility and report results to the Forum. The Forum may undertake further analysis at that time.

Maximizing the economic and environmental value of wind through regional resource planning

As discussed at length in this report, maximizing the economic and environmental value of wind energy involves a tradeoff between busbar costs, operational integration costs, transmission expansion costs, and the value of lost energy from "spilling" wind.

Access to geographically diverse wind regimes may lower operational integration costs and create access to projects with high capacity factors, but it may come at the cost of transmission investment. In deciding how much transmission capacity to build for wind there will be a tradeoff between the cost of a new line and the potential for having to redispatch or "spill" some wind in the event of transmission congestion.

New storage technologies may enter into the equation by storing wind energy during periods of transmission congestion and/or shape it into more valuable time periods. As the region looks towards a future with increasing amounts of wind energy, it will be beneficial to weigh the economic tradeoffs between these variables through integrated resource planning at the regional and individual utility level.

The Northwest Power and Conservation Council should seek a planning framework in its next power plan to maximize the economic and environmental value of wind energy. It can do so by optimizing the tradeoffs between transmission expansion and geographic diversification of wind power, and added system flexibility. In conducting this planning, the Council, other regional organizations and individual utilities can draw on the Northwest wind integration supply curve, the high-resolution Northwest wind power data set, transmission planning to be conducted by Columbia Grid, Northern Tier and NTAC, improved information regarding flexibility augmentation options, and a better understanding of the tradeoffs between demands for system flexibility.

ACTION 15: The Northwest Power and Conservation Council should seek a planning framework in its Sixth Power Plan to maximize the economic and environmental value of wind energy by optimizing the tradeoffs between transmission expansion, geographic diversification of wind power and added system flexibility.

Regional coordination of next steps

Coordination among utilities, to realize the benefits of a variable and relatively low-capacity factor renewable resource, has a distinguished history in the Pacific Northwest. Both the Pacific Northwest Coordination Agreement (PNCA) and the Columbia River Treaty brought the benefits of hydro generation diversity and energy storage sharing to the region. Those benefits were used to help finance construction of the Pacific NW-SW transmission intertie. Regional coordination of wind resources can net similar savings and benefits.

Successful implementation of this Action Plan calls for a considerable amount of work over the next several years, much of it requiring regional collaboration and coordination. Recognizing the timeliness and importance of this work, the Steering Committee has endorsed the formation of a Northwest Wind Integration Forum to monitor, facilitate and review implementation of the actions called for in this Plan. As a result, our final recommended action:

ACTION 16: The Northwest Power and Conservation Council, working with BPA and other interested organizations, should establish a Northwest Wind Integration Forum. The purpose of the Forum should be to monitor, facilitate and review implementation of the actions called for in this Plan. A Steering Committee, initially comprised of the members of the Policy Steering Committee of the Wind Integration Action Plan, should oversee the work of the Forum. A Core Analytical Team, comprised of technical staff from utilities, regulatory agencies, public interest organizations and others, should conduct technical analysis and provide analytical support to the organizations charged with implementing Action Plan items. The Steering Committee should meet once every six months to review and guide the work of the Core Analytical Team. Activities directly undertaken by the Forum should be funded by contributions from participating organizations. The Forum should be chartered as soon as practicable following issuance of this Action Plan for an initial period of two years.

VI. Complete list of Action Plan items

ACTION 1: By July 2007, the Northwest Resource Adequacy Forum (NWRA Forum) should reassess its 15 percent pilot sustained wind capacity value using currently available data on wind plant operation during periods of peak load. In 2008, the NWRA Forum should further refine the sustained peaking capacity value of wind power using the improved wind resource data set of Action 3 and other available data.

ACTION 2: Utilities participating in the Northwest Wind Integration Forum should continue to refine their study methodologies and estimates of wind integration costs using a robust stakeholder input process. They should also estimate the potential for reducing the cost and extending the supply of wind integration services through control area cooperation, more active markets for within-hour balancing services and other strategies.

ACTION 3: The Northwest Wind Integration Forum should contract for the development of a high-resolution chronological wind resource data set for the Pacific Northwest. The data set should be available by December 2007.

ACTION 4: By September 2007 the Northwest Transmission Assessment Committee (NTAC) should propose a formal technical transmission planning methodology for regional wind development. This methodology should identify the data requirements and capacity and energy planning tools needed to identify the optimal level of transmission investment needed to efficiently serve future wind development.

ACTION 5: By the end of 2007, Columbia Grid and the Northern Tier Transmission Group should convene a joint session to begin applying the transmission planning methodology for regional wind produced by the NTAC organization.

ACTION 6: By the end of 2007, the four state regulatory commissions should review and commence to amend as necessary, regulatory policies to remove barriers to more efficient use of transmission for wind and other renewable resource development. To the extent feasible, policies should be consistent across states.

ACTION 7: BPA should continue development of mechanisms to promote greater utilization of the transmission system, including more active reassignments of firm transmission rights, a conditional firm transmission product, and voluntary, multiparty economic redispatch mechanisms. BPA should report the results of these efforts to the Northwest Wind Integration Forum so that other transmission providers might benefit from this experience. The program, if successful, can be applied to integrating wind power from other transmission-constrained wind resource areas such as Montana.

ACTION 8: By the end of 2008, BPA should work with regional stakeholders to complete plans of service for the proposed West of McNary Phase 1 and West of McNary Phase 2, the I-5 Corridor, and North and South Cross-Cascades transmission reinforcements with priority given to the I-5 Corridor and West of McNary projects. To the extent available, the plans of service should identify preferred upgrades using the capacity and energy transmission planning tools called for in Actions 4 and 5. The plans should include the estimated cost and the amount of commercially

viable ATC for each upgrade. Upon completion, the plans and business cases should be reviewed by BPA's Infrastructure Review Committee.

ACTION 9: By the end of 2007, BPA should work with regional stakeholders to develop a generally applicable model for financing market-driven reinforcements and expansions of its transmission system using the proposed West of McNary project as a prototype application.

ACTION 10: By July 2008, using the analytical tools of Action 4 and building on the results of the Rocky Mountain Area Transmission Study (RMATS), NTAC should work with Columbia Grid, NTTG, wind developers and other interested parties to evaluate approaches to delivering wind energy from Montana, such as an upgrade of Montana's 500kV system and evaluate opportunities to deliver wind energy from other isolated wind resource areas.

ACTION 11: By July 2008, the Northwest Wind Integration Forum should evaluate the potential costs and benefits of a regional wind forecasting network, and develop an implementation plan in the event of a positive assessment.

ACTION 12: By July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

ACTION 13: By the end of 2007, the Northwest Wind Integration Forum should systematically address the transmission, scheduling, product design, demand management, regulatory, contractual and cost-recovery barriers to expanding the market for flexibility products and services. As part of this process, BPA should explore and report on the feasibility of expediting relief from dynamic scheduling limits on interties to other control areas.

ACTION 14: By the end of 2008, the Northwest Wind Integration Forum should sponsor an effort to further characterize options for augmenting system flexibility. These should include demand-side options, power generation technologies and storage and fuel synthesis technologies. The Northwest Power and Conservation Council should complete Action GEN-9 of the Fifth Power Plan to improve understanding of the tradeoffs between competing uses of system flexibility and report results to the Forum. The Forum may undertake further analysis at that time.

ACTION 15: The Northwest Power and Conservation Council should seek a planning framework in its Sixth Power Plan to maximize the economic and environmental value of wind energy by optimizing the tradeoffs between transmission expansion, geographic diversification of wind power, and added system flexibility.

ACTION 16: The Northwest Power and Conservation Council, working with BPA and other interested organizations, should establish a Northwest Wind Integration Forum. The purpose of the Forum should be to monitor, facilitate and review implementation of the actions called for in this Plan. A Steering Committee, initially comprised of the members of the Policy Steering Committee of the Wind Integration Action Plan, should oversee the work of the Forum. A Core Analytical Team comprised of technical staff from utilities, regulatory agencies, public interest organizations and others, should conduct technical analysis and provide analytical support to the organizations charged with implementing Action Plan items. The Steering Committee should meet once every six months to review and guide the work of the Core Analytical Team. Activities directly undertaken by the Forum should be funded by contributions from participating organizations. The Forum should be chartered as soon as practicable following issuance of this Action Plan for an initial period of two years.

Glossary

ACE, Area Control Error: A measure (in MW) of the moment-to-moment load resource balance within a control area. Technically, ACE measures the instantaneous difference in scheduled and actual system frequency and a control area's scheduled and actual interchanges with other control areas.

ADI, ACE Diversity Interchange: Coordination among multiple control areas to relax the control needed to balance load, interchange and generation 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 of the participating control areas.

AGC, Automatic Generation Control: Generation equipment that automatically responds to changes in system frequency in order to maintain target system frequency (60 cycles per second in the US) and/or the established interchange with other control areas within predetermined limits.

ATC, Available Transmission capacity: The amount of marketable transmission capacity on a defined transmission path after accounting for existing contractual obligations and operating margins.

Busbar: The point at which power from a generating resource is first delivered to the high-voltage grid. Busbar costs are calculated before considering the costs of transmitting power to load.

Capacity Factor: A measure of the actual annual energy output of a generating resource divided by the theoretical maximum output if the machine were running at its rated capacity during all 8,760 hours of a year

Capacity Value: A measure of the amount of additional peak load that can be served by a generating resource without degrading system reliability. For example, a 100 MW wind project with a demonstrated 15 percent capacity value could reliably serve an additional 15 MW of peak load.

Control Area: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the Interconnection. (Also referred to as "Balancing Area" or "Balancing Authority").

CPS, Control Performance Standard: A metric used by the North American Electric Reliability Council (NERC) to evaluate the performance of control areas. CPS2 requires that 95 percent of imbalances between generation and load above a certain threshold be rectified within 10 minutes.

Dynamic Performance: The extent to which a generating resource or other element can help support grid stability during periods of system disturbance such as a voltage drop.

Flow Gate: A point in the transmission system defined as a grouping of one or more transmission lines, used to measure power flow, usually defined when there is limited capacity across a portion of the transmission system.

LGIA, Large Generator Interconnection Agreement: The Federal Energy Regulatory Commission's standardized interconnection agreement for generating resources greater than 20 MW that proscribes a process for review of interconnection requests and a standard contract format. Created by FERC Order 2003A.

Glossary

Load Following: The deployment of flexible generating resources (or demand-side options) to adjust to changes in loads across the 10-60 minute and longer time horizon. Load following is not technically a type of operating reserve, but as a within-hour service, it is provided between system basepoint adjustments and therefore requires capacity to be reserved from the marketplace given the block-hourly markets in place in the Northwest.

OATT, Open Access Transmission Tariff: The Federal Energy Regulatory Commission Tariff defining the requirements for the provision of nondiscriminatory wholesale electrical transmission service.

Operating Reserves: As defined by WECC, the sum of Regulation Reserves and Contingency Reserves, both spinning and nonspinning. As used in this report, operating reserves include the generation capacity needed to follow moment-to-moment changes in loads and wind project output (regulation) and longer-term project output (10-60 minute) changes in loads and wind (load following). Operating reserves do not include capacity used to shape the output of wind projects over diurnal or seasonal periods.

OTC, Operating Transmission Capacity: The total transmission capacity of a line or group of lines (flow gate) after setting aside a margin for reliability and noncontract flows.

POS, Plan of Service: An engineering and economic assessment of the physical infrastructure required to interconnect a new resource to the grid or to increase the transfer capacity across a portion of the transmission system.

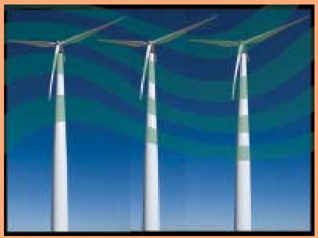
RAS, Remedial Action Schemes: Protective systems that ensure that corrective actions take place immediately following the forced outage of a transmission line or transmission system element.

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

Storage and shaping: The practice of converting the variable hourly output of a resource like wind energy into predictable volumes of power for later delivery, sometimes shaped into flat blocks of peak and off-peak energy.

System flexibility: 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 deployment of fast, responsive generating capacity to manage moment-to-moment changes in the load resource balance of a control area. Regulation is usually provided by units on Automatic Generation Control (AGC).



Appendix A. The language of Northwest 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** load 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 (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 hourly “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 a.m. – 7:00 a.m. 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. The 24-hour/day hourly real time market for next-hour delivery closes 30 minutes prior to the hour of delivery, i.e. trading for the 9:00 a.m. – 10:00 a.m. time period closes at 8:30 a.m.

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 **Control Area Operator**. Control area 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, Control area 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 bidirectional 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 Control area 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 percent of hydro generation and 7 percent of thermal generation, or their most severe single contingency. Half of the required contingency reserves must be online and spinning, the remainder must be able to be brought on line and loaded within a 10-minute period. The Northwest Power Pool requires 5 percent 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 B. Discussion of study methodologies and preliminary results from initial Northwest wind integration studies

Avista Utilities (2007)

System overview

Avista Utilities serves a control area that peaks at approximately 2,200 MW during the winter months. The company owns or controls a mix of resources (excluding nonhydro contracts) that is, on a capacity basis, comprised of approximately 56 percent hydro, 28 percent gas, 11 percent coal, and 4 percent nonhydro renewables. The utility presently integrates 35 MW of the Stateline Wind facility into its control area.

Study approach

Avista's study builds on analyses completed in 2001-02. A proprietary dispatch model driven by a linear programming engine optimizes operations with and without wind variability in the utility's system. This hourly model tracks various capabilities of the control area to meet system loads at least cost. The model contains three modules: The first optimizes hydro generation on a daily basis at the Mid-Columbia and Clark Fork projects, tracking constraints such as maximum and minimum storage and generation levels, and minimum flow. The second module creates an hourly, day-ahead preschedule that takes daily hydro quantities and allocates them across the highest-value hours possible given system constraints. The preschedule model contains day-ahead forecasts of load and wind generation. Preschedule purchases and sales made to balance system requirements are carried forward to the third, real-time module. The real-time module reoptimizes utility resources given updated one- to two-hour ahead forecasts for wind and load. It performs a task similar to the preschedule module.

Avista found the key driver of integration cost to be incremental reserves necessary to accept wind. Reserve obligations are calculated using historical data from 2002 through 2004. Specifically, regulation (up to 1 minute), load following (1 minute to one hour), spinning and nonspinning operating reserves, and forecast error are input into the Avista model as constraints on system optimization. In the with-wind variability cases, incremental reserve quantities for regulation, load following and forecast error are added to system obligations in the model.

Incremental regulation and load following reserves are calculated first by identifying levels necessary to meet load variability alone. A second step performs the same analysis, but nets wind generation against load when calculating reserve obligations. Reserve levels are increased in the with-wind case to ensure similar system operating performance levels as today (CPS1 & CPS2 in excess of 95 percent).

The regulation component was found to be constant across all hours, rising with the level of wind added into Avista's control area. Load following obligations varied both with the level of wind in Avista's control area and as hourly wind generation levels changed.

Forecast error, a product covered by reserving system capability, was a significant focus of the Avista study. Two-hour-ahead wind forecasts were compared to actual wind generation levels, reduced by: a) approximately 25 percent to account for improvements to the forecast made possible by using "state-of-the-art" wind forecasting techniques, and b) 15 MW to approximate the company's present reserve levels carried for error in the load forecast. Forecast

error was calculated at a 95 percent confidence interval and carried across all hours in the up and down directions.

Wind generation data for 2002 through 2004 calendar years was developed using the Oregon State University/BPA 10-minute wind speed database. Data limitations required the analysis to focus on the period August 2002 through July 2003. Avista considered various levels of wind from 100 MW to 600 MW, or between 5 percent and 30 percent of control area peak demand. Wind resources were evaluated in the Columbia Basin, in eastern Montana, as a 50/50 mix of Columbia Basin and eastern Montana wind, and as a multistate "diversified" mix with many smaller sites combined.

Preliminary Results

Tables B.1 and B.2 detail total wind integration costs from the Avista study. Eastern Montana wind appears to be very expensive to integrate due to its volatile nature. At 10 percent and higher penetration levels, the 50/50 mix of eastern Montana and Columbia Basin wind has much lower integration costs than either basin alone at similar penetration rates due to diversity benefits. Higher levels of diversity appear to provide additional system benefits. Costs rise predictably as wind capacity increases on the system, irrespective of the resource mix considered. Integration costs were very sensitive to absolute market price levels. Where market prices rise or fall by 50 percent from today's levels, integration costs would also be expected to change at a similar level.

Table B.1 – Preliminary Avista wind integration cost estimates ($/MWh)

	System Penetration			
Wind Location	5%	10%	20%	30%
Columbia Basin	$2.75	$7.76	$11.61	$14.95
E. Montana	$7.55	$13.01	$19.92	$24.16
50/50 CB/MT	$4.01	$6.99	$11.72	$15.09
Diversified	$2.85	$3.05	$6.65	$8.84

All figures are in 2006 dollars.

Table B.2 – Preliminary Avista wind integration cost estimates (percent of market)

	System Penetration			
Wind Location	5%	10%	20%	30%
Columbia Basin	5.0%	14.1%	21.2%	27.3%
E. Montana	13.8%	23.7%	36.3%	44.0%
50/50 CB/MT	7.3%	12.7%	21.4%	27.5%
Diversified	5.2%	5.6%	12.1%	16.1%

Avista's study broke out integration costs between incremental regulation, load following, and forecast error as follows in Table B.3.

Table B.3 – Components of integration, selected cases

Wind Capacity	System Penetration	Wind Location	Wind Shape	Regulation	Load Following	Forecast Error
100 MW	5%	C. Basin	10%	40.9%	37.6%	10.7%
200 MW	10%	50/50 Mix	6.3%	23.1%	46.2%	24.3%
400 MW	20%	Diversified	7.5%	25.1%	26.9%	40.5%
600 MW	30%	Diversified	5.9%	16.2%	43.9%	33.9%

Avista plans to acquire a diversified wind resource portfolio to keep integration costs as low as reasonably possible. To this end, the company estimates that at a 5 percent penetration level, its wind will come from the Columbia Basin. At a 10 percent level, a mix of Columbia Basin and Montana wind would be integrated. Above 10 percent, a diversified mix of resources would greatly reduce costs when compared to single sites. Avista estimates for wind integration reflect this planning assumption. Table B1 highlights in yellow the company's estimate for wind integration given its forecasted mix of future wind generation acquisition. Wind integration cost estimates are reduced substantially at the higher penetration levels due to wind site diversity.

Comparison to general study approach adopted by System Operators Committee

Avista's study, being fairly recent, conforms to the primary integration factors identified in this report.

Bonneville Power Administration (2007)

Study approach

The Bonneville Power Administration (BPA) estimated the incremental regulation and load following requirements, consistent with the procedure performed by Avista with the exception that forecast error was not separated from the load following requirement. For the load following component, this methodology derives the distribution of actual machine movement due to the combination of load following and forecast error. The regulation requirement was treated as an off-the-top obligation. The off-the-top portion of the load following and forecast error requirement was calculated as the maximum deviation of the actual combined wind and load deviation from forecast. The base case assumed zero wind penetration, therefore regulation and load following requirements in this case were to serve existing area load only. The data set used for the regulation analysis consisted of 1-minute average BPA area load and 1-minute average wind generation, normalized to the actual wind fleet capacity. The data spanned November 4, 2005 to October 29, 2006, inclusive. The load following analysis used the same data set for the no-wind, and present-day cases, and was scaled up using a two-year period of simulated 10-minute average wind generation from work performed by 3TIER.

Regulation and load following requirements were then passed to various models to simulate the Federal Columbia River Power System (FCRPS) response to the additional requirements. The Columbia Vista model, a reservoir network optimization model, was used to assess how the detailed operation of the FCRPS changed with increasing reserve requirements, to assess the FCRPS's ability to cope with large deviations from scheduled wind generation, and to investigate efficiency-related incremental costs associated with increased wind penetration and reserve requirements.

The Columbia Vista studies focusing on impacts due to additional reserve requirements used the Short-Term Vista module. The analysis was deemed "adversely affected" by the additional requirements if BPA had to market more than 150 aMW and hydraulic or fishery constraints could not be met. Results were deemed "limited concern" if the additional requirements caused BPA to market less than 150 aMW, and all hydraulic and fishery constraints were met. Two periods in 2005 and 17 periods in 2006 were selected for this study from actual planning-level runs. These were re-run with additional wind reserve requirements and load forecast uncertainty to assess impacts.

The ramping studies in Columbia Vista sought to gain insight to how the FCRPS would react to large, unscheduled changes in wind generation, both up and down. The same criteria described in the preceding paragraph were used to determine how the FCRPS operation was affected. Eight actual planning-level model runs were selected from 2006, and re-run with the wind reserve requirements and sudden, non-forecasted ramps to see how system absorbed the impact. Wind ramps were tested in 500 MW increments up to 4,000 MW. For each day, ramps were tested during the graveyard, morning load pick-up, afternoon/evening peak, and across the evening load drops.

A test version of Columbia Vista was used to estimate any systemwide changes in efficiency. For this study, one week in October 2006 (low flow condition) was analyzed with and without the additional wind reserve requirements. Changes in efficiency were determined by examining the simulated unit dispatch across the FCRPS resources.

Changes in the temporal distribution of generation were derived using a 60-year, Hydro Simulator/Hourly Hydro Simulation (HYDS/HOSS) study. Results from those simulations were passed to a modified version of the RiskMod model to assess any opportunity costs associated with changes in generation. This process uses a Monte Carlo approach varying water conditions, market price and depth, load and resource availability.

Last, a frequency study was conducted on hourly wind generation from 2001 to 2006, to assess the dependable capacity of the wind fleet to date.

Preliminary Results

The incremental reserve requirements are summarized in Table B.4.

Table B.4 – Preliminary BPA wind integration cost estimates

Wind Fleet Capacity Wind Penetration (% of Peak Load)	0 MW (0%)	733 MW (8%)	1000 MW (11%)	2000 MW (22%)	3000 MW (33%)
Incremental Requirements (MW)					
Regulation	—	6	10	27	48
Load Following	—	19	34	114	211
Contingency Reserve	—	9	13	25	38
Total Incremental Reserve	0	34	57	166	297
Incremental cost ($MWh Wind Generation)					
		$1.90	$2.40	$3.70	$4.60

All figures are in 2006 dollars.

The contingency reserve requirement is an average amount taken as 5 percent of the average energy production, defined as the wind fleet capacity factor multiplied by the capacity. Assuming a 25 percent capacity factor, this simplifies to 1.25 percent of the wind fleet capacity

The Columbia Vista studies indicated that the additional reserve requirements result in a general shift of FCRPS energy production from heavy load hours to light load hours. During periods of high stream flow, there was an increase in spill amounts with the additional reserve requirements. The model may be violating required operations above roughly 500 MW of additional regulation plus load following reserves, unless BPA undertook significant marketing (e.g. 500-1000 MW LLH).

The ramping studies that looked at the effect of large deviations from forecast wind generation indicated the FCRPS is able to accommodate unexpected ramps of the same magnitude as the regulation and load following reserve requirements. Ramps were the most difficult to manage during the light load hours, over the hour-ending 23:00 load drop, and during periods of high flows and spill operations. During other times, large wind ramps could often be accommodated without difficulty.

The efficiency studies showed that in order to accommodate the additional uncertainty, and to provide enough dynamic capacity to cover the additional reserve requirements, projects generally needed to put on more units than they otherwise would. This resulted in less efficient use by shifting the operating point off of a more optimal level, resulting in an efficiency loss of approximately 1 percent. This would equate to a loss of about 37 aMW at Grand Coulee Dam when loaded at approximately 3,700 MW. This type of study is planned to be expanded to determine if the results obtained for the October runs are similar during other times of the year and under other operating conditions. A preliminary study with higher flows indicated the efficiency loss was significantly less than 1 percent for the given wind penetration levels. This

likely is due to the fact that higher flows/generation naturally require more units in service, which in turn increases available dynamic capacity while still maintaining peak operating efficiency.

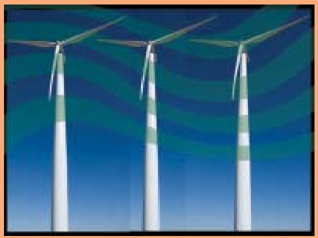
The HYDSIM/HOSS studies reflected the same general shift of energy from the heavy load hours to the light load hours. This shift moves energy from high value period to those of generally lower value. Periods of low stream flow showed the most dramatic shifts in generation.

The cost of moving energy from high value periods to lower value periods is not the only reason for revenue loss to BPA. Additionally, regulation and load following services tend to move units off efficient operating points within the hour, add incremental wear and tear to the units, and may require additional cycles of units on and off.

The cost estimates in Table 4 are based on average costs and prices and assume no other competing need for the capacity required to provide regulation and load following. It is important to note that many other factors are included in the actual pricing of regulation and load following services through the formal rate case process. The cost shown here are representative of the added cost of providing more regulation and load following over existing rates for such services.

BPA has found evidence of persistent under/over forecasts of wind generation within the day. This may result in additional shifts in energy in addition to that observed for holding reserves. This was not captured in the studies described here and may be in addition to the costs presented here

In addition to less efficient operation of the system, (including the reduced ability to shift hydrofuel supplies into more valuable hours) that was considered in the preceding regulation cost discussion, there is a need to replace the capacity dedicated to wind integration that had previously been available to meet federal preference customer load growth. While some parties may argue that the recovery of these embedded costs is simply a reallocation of the priority of the use of the FCRPS, BPA's perspective is that the FCRPS capacity is presently dedicated to future federal load obligations. Therefore if this capacity committed to wind integration, it must be replaced with similar capacity and flexibility to meet future federal load. [Note: This statement likely applies to any control area operator that integrates wind using resources that are dedicated to meet customer load obligations.]



Idaho Power (2007)

System overview

Idaho Power Company serves a control area that peaks at approximately 3,100 MW during the summer months. The company relies heavily on hydroelectric power for its generating needs, and is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. The utility has 3,087 MW of installed generation, comprised of 1,708 MW of hydroelectric generation (nameplate capacity) and 1,379 MW of thermal generation. In a typical year, 53 percent of Idaho Power's generation comes from its hydroelectric resources and 47 percent from its thermal resources. Idaho Power presently integrates 10.5 MW of wind generation directly into its system. However, approximately 380 MW of additional wind generation under contract is expected to come online near the end of 2007.

Study approach

Idaho Power contracted with EnerNex for its wind study completed in December 2006. The company used its hydro-optimization software, Vista by Synexus Global, to quantify incremental wind reserve costs. Vista's hourly optimization routine is capable of modeling nonhydroelectric generation resources, such as wind and thermal plants. To arrive at wind integration estimates, Idaho Power ran Vista with wind in its actual hourly profile, and with wind input in flat daily levels having energy equivalent to the actual hourly profile.

Idaho Power considered the same incremental reserve products as the Avista study, namely regulation, load following and forecast error. Its methods of deriving these products also were greatly the same, except that load following requirements were not varied hourly with the wind forecast. Idaho Power found early in its study that unit commitment costs on its system were not significant due to adequate liquidity in the hourly wholesale marketplace; therefore it modeled only real-time system operations and not day-ahead scheduling.

One strength of the Idaho study is its comprehensive look at potential wind locations throughout Idaho Power's service territory. This work represents the first effort by a Northwest utility to model its service territory for wind potential. The study developed five-minute historical data for more than 70 wind locations in Idaho Power's service territory for 1998, 2000 and 2005 to represent average, low, and high hydroelectric generation years. This data gave Idaho Power an excellent opportunity to consider the benefits of wind diversification.

Idaho Power considered system wind integration of between 300 MW and 900 MW, which is 10 percent to 30 percent of control area peak demand.

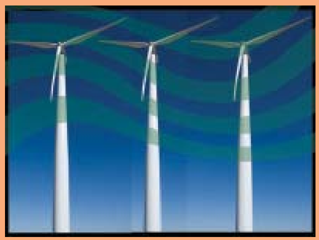
Preliminary Results

Table B.5 presents the results of the Idaho Power study. Idaho evaluated integration costs as a percentage of the wholesale marketplace, but "converted" them to a cost per MWh of wind integration assuming its PURPA tariff rate.

Table B.5 – Preliminary results of Idaho power study

Wind Capacity (MW)	Penetration	% of Market	Integration Costs $/MWh*
300	10%	15.5%	$9.75
600	20%	18.7%	$11.72
900	30%	25.8%	$16.16

** Based on a market price of $62.77-- Idaho's current published PURPA avoided cost rate.*



PacifiCorp (2003/04)

System overview

PacifiCorp serves two control areas with a coincident peak of approximately 9,400 MW during the summer. The company's resource mix is, on a capacity basis, comprised of approximately 65 percent thermal resources, 12 percent hydro (including hydro contracts), and 4 percent nonhydro renewables. The remainder is purchased power.

The utility currently integrates approximately 600 MW of wind resources (owned, purchased and managed for others) into its control areas.

Study approach

PacifiCorp first published integration estimates around the time of its 2003 Integrated Resource Plan (IRP) This study was groundbreaking in the Northwest, as no utility had to that point attempted to quantify integration costs. The original work was updated and published for its 2004 IRP.

The study evaluated incremental hour-to-hour operating reserve and system balancing costs associated with wind variability. PacifiCorp calculated the fractional incremental operating reserves necessary to integrate wind as the incremental load/wind combined variability computed on an hourly integrated basis. The fractional incremental reserve requirement was calculated by comparing the dynamic range of 1) the utility's integrated hourly load and 2) the utility's integrated hourly load where integrated hourly wind generation was netted against it. The fractional incremental requirement was taken to be the standard deviation of the combined system divided by the standard deviation of the load by itself.

System balancing costs were defined as the additional operation expenses incurred as a result of adding wind generation into its system, examples of which were incremental: market sales and purchases, unit startups, dispatching of reserve-capable units, and off-optimum operating points for thermal plants. PacifiCorp used the Global Energy Decisions' MarketSym system dispatch model to estimate the balancing costs between scenarios where flat block of energy were integrated, versus similar average energy amounts integrated using varying wind shapes. The difference in operating costs between with and without wind studies were taken to represent the additional operating costs due to wind on the system.

PacifiCorp reviewed three future years over five wind penetration scenarios approaching 2,000 MW in its study. Wind data for PacifiCorp's study was developed using actual wind site data from its system where possible, supplemented with request-for-proposal data. These data were scaled up for high-penetration scenarios, by lagging the available data sets by one or two hours in each direction.

Preliminary results

PacifiCorp evaluated penetration levels on its system from 5 percent to 20 percent in its control area. The figures are presented in Table B.6

Table B.6 – Preliminary results of PacifiCorp study

Penetration Level	Wind Integration Costs ($/MWh)
5%	$1.86
10%	$3.19
20%	$5.94

All figures are in 2006 dollars.

Puget Sound Energy (2003/05)

System overview

Puget Sound Energy (PSE) serves a control area that peaks at approximately 4,650 MW during the winter months. The company's resource mix is, on average energy basis, comprised of approximately 28 percent hydro, 17 percent gas, 22 percent coal, and 5 percent wind. The remainder is made up of contracts and market purchases. PSE currently owns 370 MW of wind resources, and integrates 220 MW in its control area.

Study approach

Puget Sound Energy (PSE) commissioned a multiphased study to estimate wind integration costs for 25 MW to 450 MW of wind capacity (0.5 percent to 10 percent of system peak demand). PSE worked with Golden Energy Services, Inc., and jointly developed analytical models that reflected actual operating conditions and estimate PSE's wind integration costs. The models considered operations-based hydro routing, balancing all reserve obligations with Mid-Columbia contract resources and the wholesale marketplace, Mid-Columbia generation constraints and option cost of reserving a portion of Mid-Columbia storage to integrate wind resources.

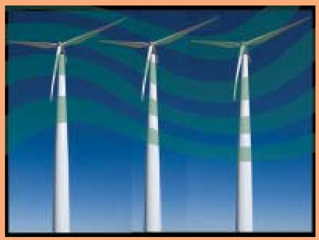
Phase 1 results from 2003 were not publicly released. However, Phase 2 published results provide a summary of Phase 1 results and methodologies. The Phase 2 report is contained in Appendix D of PSE's 2005 IRP. Since the completion of the Phase 2 report, additional analyses have been underway to incorporate new operational data.

The PSE study evaluated incremental regulation, operating reserve and forecast error costs due to incremental additions of wind at differing levels of Mid-Columbia capacity. PSE estimated that incremental regulation obligations were small. The study relied on several technical papers on regulation requirements at Mid-West wind farms due to a lack of Northwest data. Operating reserves were calculated as 5 percent of online wind generation, in line with NWPP operating reserve policies. For the Phase 1 study, PSE determined that incremental regulation would be only 1 MW on the PSE control system for a 154.5 MW wind farm.

Forecast errors were evaluated for the hour-ahead and day-ahead time periods. The hour-ahead forecast error was calculated using a 95 percent confidence level given the illiquidity of the intra-hour marketplace for system balancing. Day-ahead reserves were calculated at a 75 percent confidence level, based on PSE's expected ability to correct day-ahead imbalances in the real-time marketplace. As additional operating data becomes available and forecasting techniques improve, wind forecast are expected to improve. PSE also evaluated the sensitivity of wind integration cost with incremental improvements in the hour-ahead and day-ahead forecasts.

Preliminary results

The PSE Phase 2 study found wind integration costs to be flat across the 0–10 percent wind penetration level. Regulation costs were estimated at $0.16 per MWh. Operating reserves created no incremental cost relative to the addition of nonwind resources. Day-ahead forecast error was essentially flat between $0.82 and $0.89 per MWh of integrated wind. Hour-ahead forecast error was the largest contributor to wind integration, equaling between $2.72 per MWh at 0.5 percent system penetration (of peak load) and $3.01 per MWh at a 10 percent penetration. Total integration cost over the 25 MW to 450 MW range was $3.73 to $4.06 per MWh (year dollars not reported). PSE found that integration costs are highly sensitive to the relationship of on- to off-peak prices and to hydro conditions.



Appendix C. Technical requirements and cost estimate for development of a 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 mesoscale meteorological model. This modeling can recreate 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 mesoscale 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 mesomodel output, thereby 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 mesoscale weather models in the areas of potential wind development in the Northwest. The data set would ideally be three years long, and should represent the load shapes of the years 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 windspeed every 10 minutes and at a 4km-square grid (minimum) for the Northwest 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.

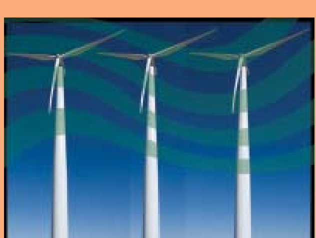
2. The data series should adequately represent the geographic dispersion impacts of the various wind scenarios. For one or more scenarios (determined by the project participants and budget) virtual anemometer data would be used to calculate power output in a way that would represent real wind plant output. 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 Washington, Oregon, Idaho and most of western Montana. Small portions of western Wyoming, northern Utah, northern Nevada and northern California 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 mesoscale meteorological simulations, members of the Data Committee of the NWIF, and members of the funding organizations.

5. The anticipated cost of the 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 three-year data set.

6. The approximate elapsed time to provide this three-year data set is approximately two and a half months to six months from execution of the project.



Appendix D. Other supply and demand-side flexibility technologies

The Next Generation of Natural Gas Turbines

Given that simple-cycle gas turbine can provide regulation, load following, peak period capacity and energy, spinning and non-spinning reserves, synchronous condenser service and poor-water year hydro firming, 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 energy will make a very modest contribution to Northwest capacity needs, and the difficulty inherent in siting new coal facilities, it is likely that gas turbines will 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. It will be their capacity capabilities that will be of greatest value to the system.

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. To do so, they must burn natural gas, and under certain circumstances, be run when electricity 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 is insufficient to meet flexibility requirements.

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. Over time, we should expect greater technological evolution – and potential cost reductions – from new gas technologies. They will, however, be a perennial source of carbon dioxide 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

Existing and new combined-cycle gas-fired turbines (CCCTs) might also 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 the 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, storage of wind energy during off-peak hours could help compensate for the limitations on off-peak 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 314-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." 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.

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

In recent years, 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 project, the Northwest Power and Conservation Council intends 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 the following matrix.

Table D-1 – Flexibility augmentation technologies

	Capital Cost (per kW basis)	Operating Cost	Footprint (m2/kW)	Life (yr)	Lead Time
Storage Technologies					
Capacitors/ Ultra-capacitors	High	Low	Small	10-15	Long
Conventional Batteries	Low	Low	Small	7	6 months
Flow Batteries-Flow/Redox [vanadium, zinc bromine, cerium zinc, polysulphide bromine, etc.]	High	Medium	Small	10 - 15	Medium
Other battery technology (e.g., lithium ion)	High	Low	Small	7	No large systems in place
Compressed Air [tanks, salt-domes]	High	Low requires natural gas	Tanks – Large Dome - Small	Decades	Medium
Flywheels	Unknown	Low	Medium	Decades	No MW yet
Pumped storage hydro	Moderate	Very Low	Large	Decades	10 yrs
NAS (Sodium-Sulfur) Battery	High	Low	Small	10 yrs	1 yr
Fuel Synthesis Storage Technologies					
Ethanol	High	Low	Large	Decades	3 yr+
Hydrogen	High	Very high	Large	Decades	5 yrs+
Generation Technologies					
Simple-cycle GT /Recip Engine	Low	High	Medium to Large	Decades	3 yrs +
Duct firing (combined-cycle GT)	Low	Low	Medium to Large	Decades	Only at construction
Fuel cells	High	Low	Medium	5 -10 yrs	2 yrs
Add capacity to existing hydro projects	High	Low	Small	Decades	2-5 yrs
Call rights on standby generation	Low	High	Small	N/A	1-3 yrs
Demand-side options					
Call rights on plug-in auto fleet	High	Low	N/A	N/A	Unknown
Load interruptibility rights	Low	High	N/A	Contract life	1 yr +
Dispatchable load cycling	Low	Low	N/A	10+ yrs	1-3 yr +
Distributed Generation	Moderate - High	High	N/A	Decades	1 yr +
Operational techniques					
Stretching wind prediction time	Can it be done?	Low	N/A	N/A	Years?
Wind plant dispatch control	?	?	N/A	N/A	Contract based

State of Technology	Where Sited	Locational Constraint	Scalable	Ease of Addition to Existing System	Efficiency and Losses	System Flexibility Applications
In development	Load	CS	No	Yes	Good	FR/LF
Mature	Source or Load	CS	Yes	Yes	OK	FR/LF/SR
Beta	Source or Load	CS	Yes	PCS Dependent	OK	FR/LF/SR
None in MW size	Load	CS	Yes	PCS Dependent	OK	FR/LF/SR
Mature for cavern	Source ???	Geology yes, tanks no	Geology No, Tanks Yes	Geology No, Tanks Yes	Good	FR/LF/SR/LF/DS/SS
Alpha	Source or Load	CS	Yes	Yes	Good	FR/LF
Mature	Unique sites	Geology	No	No ???	Very Good	FR/LF/DS/SS/SR
Early commercial	Source or Load	CS	Yes	PCS Dependent	Good	FR/LF/SR/ DS
Early commercial	Source or Load	Yes	No	No	?	DS/SS/SR
Beta	Source or Load	No	Yes	No	50% Max.	DS/SS/SR
Mature	Source	Yes	Yes	OK	60%	LF/SR
Mature	Source	Yes	No	OK	Good	LF/SR
Beta	Source or Load, fuel limited	CS	Yes	PCS Dependent	50%	LF?
Mature	Source	Yes	Limited	OK	Good	FR/LF/DS/SS/SR
Mature	Load	Yes	Yes	OK	30%	LF/SR
Conceptual	Load	Yes	Yes	No	Good	FR/LF/DS/SR
Mature	Load	Yes	Yes	OK	N/A	LF/SR
Mature	Load	Yes	Yes	OK	N/A	FR/LF/SR
Early Commercial	Load	No	Limited	OK	30%	LF/SR
Beta	Source	Yes	No	No	N/A	SR
Mature, like load interruption	Source	Yes	Yes	?	N/A	LF?

Key

CS	Conditioned Building Space
FR	Frequency Regulation
LF	Load Following
DS	Diurnal Storage
SS	Seasonal Storage
SR	System Reliability
PCS	Power Conditioning System

WIF document 2007-01

851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204
1-800-452-5161
www.nwcouncil.org