Northwest Wind Integration Action Plan

Revised Work Plan V 3.0

August 17, 2006

Section I: Background, Scope and Deliverables

The Pacific Northwest is experiencing rapid growth in wind capacity interconnecting to its electrical utility system. This growth is being driven by utility integrated resource plans with substantial concentrations of renewable resources, the recent extension (and forecasted continuation) of the federal production tax credit, high and volatile natural gas prices, the entry of sophisticated and risk-seeking capital into the wind energy sector, California's Renewable Portfolio Standard, and the potential for similar legislation in Oregon and Washington. During the next 2-3 years, an expected 1,000 megawatts (MW) or more of new wind capacity will be integrated into the Northwest grid. This is not hypothetical development, but rather projects with committed capital and, in many cases, committed buyers. Over the longer-term, the Northwest Power and Conservation Council has indicated that the region could see as much as 6,000 MW of wind if the cost of the resource remains competitive with other sources of electricity generation.

While many of the region's energy leaders have indicated a strong level of support for wind energy development, the current pace and scale of the development -- and its implications for system reliability, flexibility and costs -- has raised legitimate concerns that need to be addressed in a systematic, objective, and creative fashion. There are both short-term issues associated with managing the growth that is almost certain to occur over the next few years, as well as the longer-term challenge of positioning the region to take full advantage of its wind energy potential.

The Northwest Wind Integration Action Plan will bring together the region's best operational and technical minds to look for cost-effective ways to manage the challenges associated with a substantial wind energy portfolio. A Policy Steering Committee comprised of the leaders of the major organizations involved in renewable energy development in the Northwest will oversee this work and be asked to endorse the findings and recommendations. A Technical Work Group, comprised of lead utility staff responsible for control area reliability, power systems analysis and transmission planning, representatives of utility and customer associations, members of the wind development sector, technical specialists with an international perspective on wind integration, regional renewable energy advocates, members of ratepayer associations, and policy specialists from state government will develop the findings and recommendations. *Staff time and commitment will be essential to the success of the effort.*

Working together and in sub-teams, the Technical Work Group will conduct its work in a series of phased tasks. The first set of tasks are designed to determine the nature and

magnitude of near-term wind development, to assess the state of knowledge about impacts and costs based on current or previous Northwest utility analyses, to review what other Northwest study efforts (e.g. Northwest Transmission Assessment Committee (NTAC)) have or intend to accomplish, and to review how other regions have approached the challenges of large-scale wind integration. This phase will also address the national experience and policy issues associated with different approaches to allocating the costs of system flexibility. There may be changes to the proposed work plan resulting from the review conducted under this first set of tasks.

The second set of tasks will focus on identifying individual and cooperative operational strategies related to control area reliability, system flexibility, and wind fleet operation that can help manage the integration of the current phase of development in a least-cost fashion. These tasks will attempt to identify a range of expected costs from such strategies using existing in-house and modeling tools without conducting a complicated (and potentially time-consuming) regional study. During this second phase, a sub-team will also scope out the data requirements, analytical framework, time and cost for a broader regional study of long-term wind integration capability and costs. These tasks are expected to require about six months to complete.

The third set of tasks will identify longer-term options (and associated costs) related to transmission planning and expansion, flexibility augmentation, and wind forecasting that may be required for the region to maximize the potential of its cost-effective wind resources. By their nature, these tasks may entail further research and analysis and require 12-24 months to complete.

The specific tasks are described in further detail in Section II. At the August 14 meeting of the Technical Work Group, participants reviewed the work plan and decided on resource requirements and an appropriate division of labor to complete the tasks. They created six Technical Committees to perform the work and report back on their progress at regularly scheduled meetings of the full Technical Work Group. These Committees are:

1) Wind Data and Forecasting Committee
2) System Operators Committee
3) Wind Project Operators Committee
4) Regulatory Policy and Cost Recovery Committee
5) Transmission Planning and Expansion Committee
6) Flexibility Augmentation Committee

There are also several tasks that have been assigned to individual members of the Technical Work Group.

This final draft of the work plan will be submitted to the Policy Steering Committee for approval on August 24.

The Action Plan document will be organized in fashion similar to the Work Plan's three phases. The Plan's findings and recommendations will be drawn from the answers to the specific questions defined for each task (plus additional areas of inquiry defined along the way if deemed essential). The Action Plan will also define roles and responsibilities for any further examination and implementation of the proposed short and longer-term strategies. BPA will coordinate the drafting and production of the document. A preliminary draft will be provided to the Steering Committee members approximately 3 months into the process. A penultimate draft will be submitted to the Steering Committee for review and formal endorsement in January 2007. If deemed appropriate by the Steering Committee, some initial findings may be published prior to the completion of the final document.

The Technical Work Group will meet in full at least once per month, and more frequently if needed. The Technical Committees will coordinate additional meetings and will also be able to communicate via an electronic bulletin board hosted by the Council (www.nwcouncil.org/energy/renewable/Default.asp).

The members of the Steering Committee will be provided with a written progress report at least every month from the BPA and Council Project Leads.

Section II: Specific Tasks to Be Performed by the Technical Work Group

This section defines in detail the three phases and associated tasks to be performed by the Technical Work Group. A series of specific questions is identified for each task. Committee and Lead assignments are also specified in parenthesis.

❖ Phase 1: Assessment of Near-term Windpower Development, Knowledge, Regional Initiatives and Extra-Regional Operating Experience

Task 1.1: Determine Nature and Magnitude of Expected Windpower Development
(Jeff King, NW Power and Conservation Council and Steve Enyeart, BPA)
What are the specific wind energy projects that are either currently under construction or planned for construction during the next 36 months? What is the planned capacity of these projects and the number and type of turbines? Where and by whom are they being developed? At what busses and into which control areas will they be interconnected? What features will be provided to support system integration? What power system upgrades, if any, are planned to support these projects? Who is purchasing the output? How much is earmarked for California? How much is merchant capacity? What is the anticipated amount of cumulative development by the end of 2006, 2007, 2008 and 2009? Upon completion of the near-term estimate, estimates will be prepared for the longer-term, including sensitivities for significant market and policy variables.

Task 1.2: Summarize Current State of Knowledge about Impacts and Costs
(Clint Kalich, Avista; Elliot Mainzer, BPA)
Which Northwest utilities have performed internal wind integration studies? What were the modeling techniques and methodologies employed? What questions did they address? What were the findings? How did they compare across utilities? What were strengths and weaknesses of the studies? What lessons/finding can be drawn from the results? Are the results scalable to the next wave of development?

Task 1.3: Review Other Northwest and Regional Study Efforts
(Bart McManus, BPA; Chris Reese, PSE; Jim Caldwell, PPM Energy)
What other regional study efforts (e.g., NTAC Wind Integration Work Group, WECC Renewable Resource Task Force, Northwest Power Pool white paper on regulation sharing, CAISO Intermittency Analysis Project) are underway? Under whose auspices are they being conducted? What are their charters? Who has been participating? How are they being resourced? What have they or what do they intend to accomplish? What have they learned so far? How are they related? What are their expected lifetimes?

Task 1.4: Review Extra-Regional and International Operating Experience
(Charlie Smith, Utility Wind Integration Group)
Which regions of the country and the world have gained the greatest experience with wind integration? What is the nature of their power system and operating constraints? What are the specific technical challenges they have encountered? How have they approached issues of reliability, system flexibility and infrastructure sufficiency? What is the range of costs encountered and how have these costs been allocated? How have regulators and other policymakers impacted the pattern or pace of development?

Task 1.5: Collect and Analyze Wind Data
(Wind Data and Forecasting Committee, Task Lead: Michael Milligan, NREL)
Based on currently available data (to be provided as soon as possible with necessary confidentiality agreements from participating utilities and other sources, including simulation data), how variable are the region's wind resources? How does this compare to that of load variability? What is the distribution of this variability? How often do severe ramping events up/down occur? To what extent can they be mitigated by geographic diversification of wind projects? Does the current pattern of development indicate that we are enhancing, or reducing geographical diversification?

Task 1.6: Assess National Experience and Policy Questions Associated with the Allocation of Regulation Costs Associated with Wind (and other) Generation Resources
(Regulatory Policy & Cost Recovery Team, Task Lead: Mark Jackson, BPA)
How is each of the participating NW utilities currently recovering the costs of regulating and load following capacity? How are -- or would -- other opportunity costs associated with wind variability be recovered under current rate constructs?

Is it equitable and/or technically feasible for the purposes of ratemaking to isolate the impacts of individual generators or loads on regulating and load following requirements?

What is the appropriate billing determinant if such an approach is taken? What can be learned from the experience of utilities in other regions that have grappled with the question of cost allocation for wind integration? Is their experience applicable to the Northwest?

❖ Phase 2: Identification of Strategies to Integrate Near-term (next 2-3 years) Windpower Development

Task 2.1: Define and Compare Current and Anticipated Within-Hour Operational Impacts Associated with the Growth of Regional Wind Generation

(System Operators Committee)

What are the specific within-hour operational issues that different control areas are experiencing with current and expected wind generation? What are the similarities and differences across control areas? How are these impacts and their costs expected to change with the committed and potential growth of wind over the next 2-3 years?

Task 2.2: Develop Individual Within-Hour Control Area Operating Strategies

(System Operators Committee)

What specific operating strategies have control areas already deployed to manage the variability of wind in their systems? What other types of strategies would prove effective in managing or enhancing the current phase of growth short of procuring additional regulating reserves[1]? Sampling two or three control areas, what is the estimated MW and cost savings, in terms of reduced regulation requirements, of limiting ramping events over various numbers of hours in the year? How much energy would be lost?

How much further might these strategies stretch existing system flexibility before having to allocate additional capacity to regulation or to purchase additional regulating reserves?

Task 2.3: Explore Cooperative Within-Hour Operational Strategies

(System Operators Committee)

Once flexibility optimization strategies have been established on a control-area-by control area basis, how much additional efficiency might be gained through a pooling of regulating reserves? How exactly would this (or some equivalent) be accomplished? Who might administer such an arrangement? What other types of cooperative strategies might be effective in reducing aggregate regulation requirements? Prior to completing a broad regional study, estimate a range of capacity and cost savings that might materialize from such efforts.

[1] For purposes of this document, "regulation" refers to managing within-hour control area variability and "load-following" covers the hour-to-hour and beyond time frame. Both functions utilize system flexibility.

Task 2.4: Establish Benefits, Data Requirements and Costs for Improved Region-Wide Wind Forecasting
(Wind Data & Forecasting Committee, Task Lead - Pascal Storck, 3Tier)
To what extent have current "best practices" wind forecasting tools been demonstrated to reduce ancillary service requirements (i.e., over simple persistence forecasting)? What specific SCADA, meteorological tower and other data is required to provide "best practices" wind forecasting over the different time horizons of interest to system operators? If additional met towers are required to improve forecasting, how much will they cost and who should finance and maintain them? How do we address data confidentiality issues?

Task 2.5: Active Wind Project Output Management
(Wind Project Operators Committee with review by other Committees)
To what extent can the output of wind turbines be dispatched or controlled? What is the appropriate economic/operational paradigm to achieve limited dispatch and control of the wind fleet for both the onset and departure of wind ramping events? How will it affect the economics of wind generators and/or the costs to end-use customers? Can market mechanisms, such as tradable ramp rates, be applied effectively to this operational objective? What is the cost-effectiveness of the various means of obtaining system balance with wind controls vs. other mechanisms?

How can project owners be ensured that control and dispatch will be applied equitably to all generators (or at least all wind generators) and that system operators will not become overly reliant on controlling the wind fleet to ensure control area reliability?

Are there certain things that NW wind project owners/operators might do, such as agreeing to limit their ramps under certain circumstances or participating in a well-structured wind forecasting network that would argue for allocation of incremental flexibility costs to a broader base of customers? Is it appropriate to consider environmental externalities in answering these questions? If so, what can we use as a reasonable estimate of such benefits?

Task 2.6: Define Power System Impacts and Costs over the Hour-Ahead and Longer Time Horizon
(System Operators Committee)
What are the physical operating impacts of wind, in terms of increased uncertainty and changes in unit commitment, across the hour-ahead to month-ahead time horizons? How do the operating impacts differ between utilities primarily providing control area wheeling services versus those purchasing wind energy for load service? What are the specific operating constraints that limit the use of system flexibility for wind integration? Which constraints are obligatory and which involve tradeoffs of merchantable products (e.g. ancillary services) creating opportunity costs?

Building on previous studies and current modeling capability, what is an *estimate* of the range of opportunity costs of these impacts expressed in $/installed MW of wind? How do they vary from system to system, from primarily hydro to primarily thermal systems

and for different amounts of wind generation? How wide is the distribution of these costs under different forward price/volatility scenarios as well as different assumptions about future operating constraints? How do these costs compare to those developed for other utility systems in the US and abroad?

Task 2.7: Develop Individual Hour-Ahead and Day-Ahead Operating Strategies ***(System Operators Committee)***
What specific operating strategies have utilities deployed to manage wind variability in the hour-ahead and day-ahead time frames? What other types of strategies would prove effective in managing or enhancing the current phase of growth short of procuring additional load-following capability? What is the role of wind forecasting in such strategies? How much further might these strategies stretch existing system flexibility before having to augment load following capability?

Task 2.8: Explore Cooperative Hour-Ahead and Day-Ahead Operating Strategies ***(System Operators Committee)***
Are there analogues to pooling of regulating reserves that could leverage regional system diversity and liquidity in the real-time and day-ahead markets? What other forms of cooperation between system operators might prove effective in minimizing load following costs and capacity requirements?

Task 2.9: Scope out Data Requirements, Analytical Framework, Cost and Estimated Timeframe for Completing a Longer Term Regional Wind Integration Study ***(Full Technical Work Group)***

❖ Phase 3: Identification of Long-Term Operational, Infrastructure, Market and Policy Requirements/Costs to integrate up to 6,000 MW of Wind[2]

Task 3.1: Transmission Planning & Expansion Issues, Activities and Future Options ***(Transmission Planning and Expansion Committee)***
Assuming that broader regional diversification will be needed to manage the variability of a large regional wind fleet, which regions of the Northwest would be candidates for transmission expansion? What has been done to date to explore such expansion options? What have been the estimated costs of the required infrastructure?

What modeling capability and supporting data are needed to assess the bulk transmission requirements for the longer-term development of wind power forecast in Task 1.1? What bulk transmission upgrades and additions, if any, are needed to support the development of the long-term potential identified in Task 1.1. What are the estimated costs of these expansions and additions? What are the principal impediments to development? What are the tradeoffs, if any between geographically strategic additions of flexibility augmentation and new bulk transmission capability?

[2] The 6,000 MW figure is based on the potential wind resources identified in the Council's 5th Power Plan.

What are the additional -- if any -- analytical, staff, data, and financial resources required for strengthening existing transmission planning efforts? What are the specific renewables-related issues that need to be addressed through a regional integrated resource plan or by future institutions with responsibility for transmission planning?

Task 3.2: Assess the Capacity Value of Wind
(Ken Dragoon, PacifiCorp)
What work has been done to date in the Northwest on the capacity value of wind? Are there meaningful differences in analytical approach and findings for *planning* reserves as opposed to *operating* reserves? How do the Northwest findings compare to experience in other regions? In practice, how have the region's utilities perceived the capacity value of wind from a day-to-day operational perspective? What capacity value should wind be assigned for the purpose of assessing system reliability? What capacity value should wind be assigned for the purpose of economic evaluation in resource planning?

Task 3.3: Identify Flexibility Augmentation Strategies and Costs
(Flexibility Augmentation Committee)
Sampling two or three control areas, what is the incremental amount of regulating and load following reserves required as a function of an increase in wind generation, once existing or potential operating strategies are unable to extract additional flexibility out of the existing system? What is the shape of this curve and how does it change given different operational strategies? Once existing system flexibility is exhausted, which supply and demand-side strategies might regional system operators undertake to enhance the regulating and load following capability of their systems? What are the estimated costs? Are there regional, cooperative approaches that might be more efficient and cost-effective?

If one assumes that the region will need firm, dispatchable capacity to meet its incremental load growth, what kind of generation technology is available to provide this capacity while at the same time having the flexibility to ramp up and down around a sizeable fleet of intermittent renewable energy generation? How can the region develop a planning framework to make use of this kind of incremental generation in the most cost-effective manner possible? For BPA and the publics, who would coordinate the development of this type of capacity? What are the required lead times? If the capacity technology is gas-fired, will there need to be similar flexibilities built into the gas procurement chain? Will changes in financial arrangements *vis a vis* gas contracts (for pipe capacity and physical gas) be required?

What current and future demand-side and storage approaches might provide system flexibility and capacity? What are their costs? Have they been proven effective in other regions?

Task 3.4: Assess the Architecture of a Potential Regional Wind Forecasting Network
(Wind Data & Forecasting Committee and Wind Project Operators Committee)
What are the strengths and weaknesses of the California PIRP wind forecasting system? Which aspects might be beneficially applied to the Northwest? Which should be avoided?

Would a centralized wind forecasting network be of added value to the Northwest? Who might administer a centralized wind forecasting network in the Northwest? How much might it cost? Who would pay for it? How would concerns about market sensitive data and FERC Standards of Conduct be addressed? Would a single or multiple vendors of forecasting information be preferable? Would it work for IPPs?

Task 3.5: Identify and Analyze Regulatory Issues Associated with Wind Integration
(Regulatory Policy & Cost Recovery Team, Task Lead Stefan Brown, OPUC)
Which recommendations emerging from this project will require the establishment of new rate-making incentives or cost-recovery mechanisms? Are there precedents for such mechanisms in other regions of the country? How successful have they been? How and by whom have they been developed and implemented?

How do regional ratepayer advocates view these issues and potential solutions, and what is their tolerance for cost increases to integrate a growing wind fleet?

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