Northwest Wind Integration Action Plan
Technical Work Group Meeting
Sept. 25, 2006
Notes
Points made in discussion after each presentation are bulleted

Review of Steering Committee Meeting, Elliot Mainzer, BPA

The steering committee ratified the work plan on Aug. 24. Members said they see this as a significant business issue. Chief issues raised by members include:

1) Pressing nature of the front end of the growth curve.
2) Almost total illiquidity in the market for load following and regulating reserves.
3) Defining the capacity value of wind.
4) Storage and the role of demand side management.
5) Costs of transmission given the limited capacity factor of wind.

Subcommittee Progress Reports

Task 1.1 Nature and magnitude of expected wind development. Steve Enyeart, BPA.

Jeff King developed a list of wind energy he sees coming on 2006 through 2009, based on information from utilities' requests for proposals and submissions to PUCs. I cross-referenced with known project sites. Jeff assumed 200 megawatts of wind energy sales from the Northwest to California in 2006 and extrapolated that through 2009. He assumed 75 percent of Northwest publicly owned utilities' load growth would be served by wind. The base case came out with ~3000MW of additional wind in 2006-2009.

To produce a low case (as suggested by Jeff King), I reduced Northwest load growth, assumed 25 percent of public utilities' load growth would be served by wind, and took out sales to California after 2007. I reduced how many projects would come on line in each year to match the lower estimates. This work will give 3 TIER and Michael Milligan the geographic location of projects so they can crunch flows from adding the weather.

Actions suggested:

- Contact Dave Warren of WPUDA, he's up on all the Washington PUD actions.
- Look at different assumptions about where wind is developed.
- We'll make this information available so utilities can critique it.

Task 1.2: Summarize current state of knowledge of impacts and costs. Clint Kalich, Avista.

We're looking at wind integration performance studies. Some IOUs use system dispatch models. Puget is focused on contractual rights at mid-C [mid-Columbia]. Avista modeled its entire system. BPA is focusing on balancing capacity requirements and impacts of

wind forecast errors on day-ahead and real-time operations. Wind has small penetration rates relative to utility size. We're trying to discern why the market for capacity products is illiquid. We see that multiple correlated sites are more expensive to serve than non-correlated.

Other comments during the session:

- Avista is selling a limited amount of regulating services.

- NorthWestern's wind penetration is 9 percent.

- At some point, the flexibility of hydro to absorb wind will run out. At that point, we have to start adding thermal to provide regulating services.

- The system can do a lot of things, but we're no longer running our hydro system purely for economics, we're running it in part for wind integration.

- PowerEx – We have a lot of spare hydro capacity in B.C. at times of year, but how do I provide it to the Avista control area?

- Bart McManus, BPA – My primary objective is not to have to add thermal. You can control wind at our dispatch center. So far, we're just trying to make sure we can accommodate what's in so far and what's going to be built. Then we'll look at the costs.

Task 1.3: Review other regional study efforts.

Chris Reese, Puget and chair of NTAC group, reporting on NTAC studies:

If wind resources are located on the lower Snake and lower Columbia, it affects transmission paths West of Cascades, West of McNary and South of Hanford. Wind located right on top of the transmission system puts pressure on the cross-Cascades paths. If you add substantial wind in Montana, you add pressure on the Montana path. If you add wind in Wyoming, you add pressure on Bridger West.

The hydro system is a cheap resource itself. With the hydro and wind generation sitting on the same transmission lines, it forces a lot of flow. There's a tradeoff in generation v. how big a transmission system we want.

Wind output is very varied. There are times of no wind. Sometimes the wind shows up at peak, sometimes at night. From a transmission perspective, we need to have a discussion about what risk we're willing to take, what criteria we should use for a build decision. Possible studies:

1) Let wind be the least-cost resource to dispatch and do a stress test on the transmission system.

2) Analyze what generation would run in Northwest with and without wind.
3) Get a detailed hydro model that doesn't exist for transmission use. Get a detailed wind model, and do a simulation for Oregon, Washington and Idaho.
4) Look at the extreme winter peak, assume we shut down thermal units, ramp up wind at 10 year peak loads, and just measure stress on the Cascade path.
5) See how increments of wind affect transfer capability to California.
6) Do production simulation effects on load areas not at extreme peak.

Questions and comments:

- Has anyone cross referenced where the wind is and where the transmission is? Windy dirt 300 miles from a line doesn't help.

- Transmission planners have a sense where there's a need for capacity now, and we know where wind is likely to interconnect because we have a long list of requests. What we don't know is when wind is going to come on.

- We have a difference of philosophy on triggers for putting in transmission. We could build a cross-Cascades path and shut down all thermal on the west side in spring. But is that reasonable for the expected hours per year of production?

- We don't know what's it worth to steer where wind is going by giving signals to industry. Utilities could define areas that would be good candidates for wind.

Bart McManus, BPA, reporting on WECC Renewable Resource Task Force and NWPP Regulating Reserves Sharing Agreement

The WECC board wants to find out the effect of more renewables in the WECC interconnection. We'll have more data thanks to the Northwest Wind Integration effort.

The regulating reserve sharing agreement of the Northwest Power Pool is looking better. In two weeks we should have something to go to the power pool operating committee. What the NWPP comes up with will bear on what we do here. We are in agreement on how we would do reserve sharing. Four entities have signed agreement to do ACE diversity interchange. A white paper will be out in about two weeks.

Task 1.5: Collect and analyze wind data. Brian Parsons, NREL

To analyze wind integration issues and potential solutions, we need to know the likelihood that the wind will be blowing hard 100 miles away as well as here. That takes good time-synchronized data over several years. What we have works well with plants that are already on line.

For plants not yet built, one option is a good meso-scale model. There are people who can back-cast the weather. You plunk virtual anemometers in the model and extract virtual wind speeds. You can construct any geographic scenario and see what the changes

on your transmission system would be. This also could give direction to developers. We at DOE think these studies are critical. We have funders to kick in $100,000 to $200,000.

Cost is proportional to resolution and amount of ground you're trying to cover. Resolution of 10 kilometers will miss the effects of anything smaller than 30 kilometers. Once you've got the model running, extracting data from lots of point is no big deal. I'd suggest several hundred virtual anemometers.

You have to do multiple years. The wind data comes from the National Weather Service. It doesn't work on a less than 10-minute interval. More complex terrain is more difficult to model, particularly in a larger resolution scale.

Comments:

- The data set that OSU and BPA have are the gold standard for the wind resource at those five locations. The problem is how to interpolate between those five stations. Mesocale modeling, while not perfect, is best when data is limited.

- I'm most interested in capturing sites that would serve my load.

- We'll get the proposal to the wind subcommittees for review for a week.

Task 1.6 Assess National Experience with Cost Recovery, Mark Jackson, BPA

About 3 percent of our regulating requirement of 400-500 MW is due to wind. We don't have a rate to recover that component of wind. Load-serving entities in our control area pick up within-hour balancing for all the wind in our system whether or not it stays in our system. The alternative is to allocate some of the regulating and following costs to wind. It's difficult to verify from a billing perspective; it's not spinning a meter somewhere. What we're doing now doesn't seem to follow causation. We're looking at proposing a simple 5 percent of capacity charge to cover the regulation plus a portion of load following, at 7.31 per kW month, to compensate for use of the system. Another alternative is to increase the estimate of what we'll need for regulation for next three years and assign the cost to loads. No decisions have been made on this issue yet.

Task 2.5 Active Wind Project Output Management: Natalie McIntire, RNP

This group will answer technical questions on what wind farms can do to help with tail events. Developers and utilities are not excited about having control areas dispatch their plants. What criteria would be used by control area operators? What's an event that requires the dispatch of wind plants? How do we share costs and risks?

Outside Presenters

Jim Blatchford, CAISO

Ten-minute deviations are a real problem in our market. We net out deviations over the month and charge wind producers the average monthly market clearing price for the balance, but that's less than the 10-minute price; there's a cost that is borne by ratepayers. The deviations a normal generator is subject to on a 10 minute basis, a wind generator is not subject to. Wind generators have to schedule based on state-provided forecast.

David Hawkins, CAISO

California has a renewable portfolio standard with 20 percent of energy by 2010 to come from renewable resources and 33 percent by 2020.

We're going to see a lot of wind now through 2010, then most wind will be fully developed and we'll ramp up solar. The Sterling engine is being developed for solar. It has zero inertia, goes from 0 to full output or back in one second. If you like wind, you will really like solar.

One of the major issues is how to get transmission built to wind and solar areas under FERC rules. If you can't justify a line for network reliability or economics, the first generator at a site is socked with the whole cost of a major line. We're going to FERC with a new proposal to justify building transmission for a cluster of generation, using the model of the gas pipeline industry. We'd get statements of intent and build a line. Developers would refund the ratepayer investment and get capacity in return. The problem is if eight companies say they will participate but only six do, who takes the risk?

CAISO schedules wind on a 1-hour basis. But we've discovered the 10 minute variation is quite significant; wind moves around. A load following study using CEC consultants, of which GE energy is the biggest piece, claimed no current or expected problems in California between now and 2010. CAISO does not agree with that position. As we get to 5,000 MW in Tehachapi, it will dominate wind, and it peaks at night and drops off in the middle of day. The real issue is the ramps. In April and May when all the hydro was running flat out, we lost regulation from hydro and had no place to sink wind energy. It was a significant problem for several months. We pushed frequency up a bit.

We have a must-offer requirement, so almost all generation bids in some variability into the load following market. We need units with one-hour start time and much smaller minimum generation so we can handle light load hours. We are not seeing new peaking units built.

Other issue is how do you shape the energy. I would love pumped storage from an operations perspective. We have proposed to the CEC to do research on other types of storage capacity in 1 to 2 hour slots, fast-ramping mitigation type storage, more than a flywheel – hydrogen, flow-based batteries.

Our ancillary services market is anemic. FERC and everyone else is going to push hard to get more into demand response. We will look at loads willing to take variability signals,

for example, a cement contractor gets cheap energy in some periods and ramps up production then.

Questions and comments:

- When we talk about fluctuations in wind generation, does it introduce something new into our ideas of governor interaction?

- A lot of governors are change-in-frequency or change-in-time. Governor response is used during sudden changes, regulation is in more gradual.

Abe Ellis, Public Service New Mexico

Public Service of New Mexico has a peak load summer of 2,400 MW in July and August and a minimum load of 1,400 MW in spring.

Wind is going on the plains of the state east of Albuquerque. We have a single 204 MW wind farm owned and operated by a third party. We integrate its power and provide ancillary services under a long-term contract. A second wind farm of 90 MW should be in service next two months. Its output will be dynamically scheduled into a different control area in Arizona. It will be physically in our control area but not contractually.

Based on peak capacity, we're about 8 percent wind , off peak capacity we're about 15 percent. On average for year 2 percent of energy comes from natural gas, 4 percent renewables, 4 percent purchases. About 60 percent of our energy comes from coal, 25 percent from nukes. Both of these resources typically run baseload. We have a few gas units that we typically don't run except when it's not at a loss. When no gas is on line, we do automatic generation control by backing off large coal units. We typically use 25 MW to provide regulation. Coal units ramp slowly. It's not ideal.

Impacts of wind are modest so far. We realized cost reductions to operate our control area more efficiently. We changed our management of the CPS2 index from 95 percent or higher to 90 percent of necessity. The lower the standard, the fewer resources you need.

Regulation is where the impacts occur most. We assume no wind on system in our day-ahead forecasts. We have just one wind farm and can't count on diversity there. We resolve all variability from wind in real-time regulation. Providing regulation by backing off coal carries significant opportunity costs.

We have commissioned a wind integration study to quantify this cost. We did a little study ourselves showing the impact is not zero and not infinity and realized we're out of our league.

We don't have tariffs to recover costs of the next amount of wind. Under OATT ancillary service regulation, we're allowed to recover 1-1/2 percent based on the peak load of those we serve. If we're using 30 MW to regulate 2,400 MW of load, we're recovering costs,

but not if goes beyond 30 MW. We are supportive of the development of a conditional firm transmission product. Today, developers have trouble financing projects

We have very high ramps throughout the year. CPS2 is issue we have to watch; with high ramps, we ramp up negative points quickly. We get day-ahead, hourly and 2-minute forecasts on 15 minute intervals. Sometimes operators act preemptively based on these forecasts. Regulation is difficult to find. We would love a deeper market.

We are not in a position to offer regulation service because we don't believe we can recover the cost under our existing tariff. We're obligated to provide if someone wants it. The path of least resistance was to have another provide regulation. The tariff doesn't let us recover cost as it's now worded. Because we're at minimum CPS2 level and have no efficiencies left to exploit, a 100 MW addition to wind requires us to increase regulation 5 MW. Looked at as 5 MW we have to take off the market at an average $40 MWh, the opportunity cost of 5 MW is huge over a year.

Tristate G&T delivers power to co-ops in our state. If wind wanted to integrate with them, outside our control area, we'd have very little leverage on how much cost impact we could recover, because their peak load wouldn't have changed but they'd be putting an additional regulation burden in our control area. We need policy and regulatory change along with cost estimates.

Closing Discussion

- What can we squeeze from our existing resources? Power pool regulation sharing is clearly a step New Mexico has taken.

- I'd like to find out what the Northwest can do happily with a good system that works well.

- New Mexico is a small control area with no flexible resources, and they're at 8-9 percent wind with 20 percent off peak. It certainly puts into question what we're concerned about.

- Putting in some fast-ramp gas would lose a point or two of efficiency but provide variable reserves. ACE sharing, dynamic scheduling is a way to do control area consolidation without giving away the control. WAPA wind goes into Denver with dynamic scheduling they couldn't control themselves. There are a lot of relatively simple solutions before we hit the steep parts of the cost curves.

- New Mexico reduced its compliance standard, which means it leans more on the interconnection for stability. I hate the way the criteria are written – if compliance is good during the last week of the month, it can make up for the first three weeks. When California does the same thing, it has a much bigger impact on the system. If the Northwest goes the same route, we will have frequency excursions.

- When California let frequency run fast, it probably took back that energy when the frequency was slow. Would they have been so willing to dump energy and make frequency run fast if we had a cash-out of frequency dumps? India started charging for unscheduled interchange on a 15 minute basis and set the price of inadvertent based on the price when the inadvertent occurred. California would have gotten $1 per hour when frequency went high, then it would have paid $50-$100 for the energy it took. When India implemented this program, its standard frequency error went from 1.5 hertz to .2 hertz. It reduced frequency error by factor of 5.

The group settled on Oct. 30 for next full Technical Work Group meeting.

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