Resource Adequacy Steering Committee Meeting

March 9, 2012

# Notes

**In Attendance**: John Fazio, Rob Diffely, Pat Byrne, Tyler Llewellyn, Stefan Brown, Phil Popoff, David Clement, Steve Oliver

**On the Phone**: Tom Karier, Howard Schwartz, Steve Weiss, Dave LeVee

[We did not write down the names of the folks on the phone so, if you were on the phone and are not listed or if you are listed but were not on the phone, please let me know.]

**Approval of Assumptions and Decision on “Yellow Warning” Indicator**

John Fazio started the discussion with an overview of the 2012 schedule for the Adequacy Forum. Key milestones include:

* Today: Review 2015 test case and draft State of the System (SOS) report
* June: Update load and resource data
* June: Finalize SOS report format
* July: 2017 assessment/SOS report to technical committee for review
* Aug: 2017 assessment/SOS report to steering committee for review
* Sep: 2017 assessment/SOS report to Council and public
* Oct: Identify future enhancements to the analysis (tech committee)

Rob Diffely then went over the current assumptions being used for the analysis (see his presentation at <http://www.nwcouncil.org/energy/resource/meetings/2012/03/Steering.htm>.)

The in-region market is made up of Independent Power Producers (IPP). During October through April the full IPP capability is assumed for the market size. During May through September, the NW market is limited to only 1,000 MW.

In the October-through-April period, the out-of-region market is equal to the minimum of surplus SW capacity, limited by the once-through-cooling (OTC) requirements and the minimum intertie availability from south to north. For 2015 this assumption yields about a 3,200 MW SW market for December and January. Between May and September, only 1,000 MW of SW market is assumed to be available and only during off-peak hours.

The group then discussed the issue of market access. The idea is that the market is not as fluid as one might think and that at least a portion of the market may not be available for any number of reasons. After much debate, it was decided that for the 2017 assessment, no adjustments would be made for market access. However, prior to next year’s assessment, the Forum will devote some time to review conditions under which the market might be limited and decide then if any adjustments to the model or data would be necessary.

John then described the use of borrowed hydro, which is hydro energy generated by drafting below the drafting rights elevations. This energy is then replaced as soon as possible, even if it means purchasing expensive power from the market. The monthly limit for borrowed hydro is set to 1000 MWa. John met with Steve Kerns, Kristine Bartlett and other BPA staff to discuss possible impacts on minimum flows for Chum during the late fall and winter and on refill probabilities for early April. Based on rough calculations, it was decided that this level of borrowed hydro would not affect either. Refill probabilities in August could be affected but in those months, the refill targets are maximum elevation targets (whereas in April they are minimum elevation targets). It is fairly easy to assess impacts to refill but much more difficult to assess impacts to hourly or daily minimum flows because the model’s hourly hydro dispatch is done in aggregate.

John said that he is currently using BPA-fleet historical hourly wind data (2008-10) but is waiting for a new 40-year synthetic wind data set from BPA. John said the wind data is not temperature correlated but he is hoping that BPA will be able to produce a temperature-correlated wind data set prior to the next assessment. Ben Kujala (BPA) is the analyst doing this work.

Stefan Brown asked if we are still using the 5% capacity factor for wind. Rob indicated that because of the revised standard, that factor is no longer needed to do an adequacy assessment. However, he did acknowledge that it would be useful to calculate a value to include in reports such as the White Book.

John said that he has developed a method to assess the effective load carrying capability of wind on an annual basis. His initial results show about a 22 to 24% factor for the current level of installed wind and based on the BPA wind fleet historical data. He is exploring the use of this method to assess monthly values and more importantly, hourly values. Although, he is not sure the methodology will work for assessing hourly values.

Steve went back to the discussion of market access and asked about the sell-ahead market. He said that BPA and other utilities, including the IPPs, often sell ahead in anticipation of surplus generation. This effectively increases the short-term load and could reduce the amount of available market supply. A question was asked whether such sell-ahead actions include call-back provisions. The answer, of course, is that each transaction is different and may or may not include call-back provisions. Steve said that this could be treated under the more comprehensive topic of modeling market uncertainty.

Steve added that he thought assumptions about standby resources should be conservative. He said it was not clear to him if one utility would use an SB resource for another utility’s need. He said the current assumptions were OK for now but that we should continue to explore this issue.

Phil asked if the sum of reserve requirements for all utilities equals the amount required for the region. Steve said that in order to “share” reserves, there has to be good communication, transmission and other infrastructure. Because we do not have that perfect mix, it is likely that the sum of utility reserve requirements will be larger than the amount assessed for the region (as though it were one utility).

Steve said that the mix of communication and other infrastructure is what he defines as “market friction.” He also said that during times of need, the amount of available reserves or market supply may go down because the utility with surplus may want to hold on to more resource for security.

Tom agreed with Steve in that this topic falls under the more comprehensive assessment of how to model market uncertainty. He suggested that the technical committee continue to explore ways in which to do this.

John then described a proposed method of delineating between the red, yellow and green adequacy conditions. It was suggested to him, after the last steering committee meeting, to use uncertainty in the load forecast and conservation achievement as a means for delineation. More precisely, the suggestion was to assess the “expected” LOLP based on expected load and expected conservation savings. Then an “uncertainty” scenario, with higher loads and lower conservation savings (amount to be determined by the technical committee and approved by the steering committee), would be analyzed.

The assessment of adequacy status would then be made based on both the expected LOLP and the “uncertainty” scenario LOLP (let’s call it LOLPU for now). If the expected LOLP is greater than 5% then the adequacy status is RED. If both the LOLP and LOLPU are less than 5% then the status is GREEN. If the LOLP is less than 5% but the LOLPU is greater than 5% then the status is YELLOW.

Dave asked if we had done this uncertainty analysis. John said that he had, in a manner of speaking. The LOLP for 2015 using the current load forecast is about 1%. However, when he did this same analysis with last year’s forecast load for 2015, the LOLP was about 5.5%. He noticed that while the annual average load did not change much, the peak loads (in key winter and summer months) dropped by as much as 2000 MW in some hours. A conclusion that one could draw from this analysis is that the 2015 power supply is approximately 2000 peak MWs away from becoming inadequate. This 2000 MW gap could be made up of load forecast uncertainty or a combination of load uncertainty and conservation-savings uncertainty. John suggested that the technical committee could begin by determining the 90th percentile likelihood of “load gain + conservation loss” uncertainty and use that value to assess the LOLPU. He said that both analyses would provide good information, 1) knowing whether the 90th percentile uncertainty in load + conservation savings puts us in a yellow status and 2) also knowing how “far” we are from becoming inadequate.

Dave asked if the LOLPU threshold should be set higher than 5% for the yellow delineation. John said he doesn’t know now but may have more insight after some studies are done. The steering committee needs to review the implementation plan to make sure that the actions called for under each status condition are still appropriate. Phil said it probably wouldn’t be a bad idea to be conservative in the determination of the adequacy status. In other words, he said it would probably be better to indicate a worse problem than really exists than the opposite.

Steve suggested not using a different threshold for the LOLPU because it would cause confusion.

John suggested that we could use the Council’s high load forecast and the Council’s low end conservation target instead of assessing a 90th percentile amount. Tom said that would be too conservative because the likelihood of seeing both of those conditions would be much lower than 5%.

The group agreed that the technical committee should take a look at both the Council’s load forecast and conservation range and come up with an amount of uncertainty (for both combined) that would be a reasonable breakpoint between green and yellow status. He wasn’t convinced that the 90th percentile was the right number. He wanted the technical committee to look at past forecasts and actual values to get a sense for what a reasonable breakpoint might be.

**Review Preliminary Results for 2015 Test Case**

John presented a summary of the 2015 adequacy test case. This case is for testing purposes only and is not intended for release to the general public, even though the data used is current.

John described the draft format for the initial State of the System (SOS) report. The report will be broken up into 3 parts, 1) a one-page abstract; 2) a 5 to 10 page executive summary and 3) an appendix section.

The suggested approach is to provide the answer right up front – RED, YELLOW or GREEN, followed by a table of adequacy metrics and their thresholds including the LOLP, which is the metric identified in the current adequacy standard.

The appendices will include summary tables and graphs and will be divided into annual, monthly and hourly sections. The information will include an estimate for monthly LOLP values and expected likelihood of standby and market resource use. Those charts will include the 90th percentile use also. The monthly data will also show duration curves for use of market supply (in this case combining in-region and out-of-region markets) and use of borrowed hydro.

The hourly section will be similar to the monthly section but will include hourly duration curves over all hours of each month and also duration curves for the 90th percentile months. The information will show use of market resources and borrowed hydro. It may also include average dispatch by fuel type and duration curves by fuel type. The appendices will also include a summary of and statistics for simulated curtailments.

[After the meeting, it was proposed that the appendices also include a resource/load table, similar to those published in the White Book and the NRF. It should be noted, however, that if such tables are published, a clear definition of how resources are counted (and how that might differ from other reports) must be included.]

John said that it may be difficult at this time to know what data will be most useful to utility planners and suspects that the format and content of the SOS will evolve.

Results for the 2015 test case show the region’s power supply to be adequate, with an LOLP of about 1 percent. No “uncertainty” scenario was done so it is not clear whether the adequacy status is green or yellow. The following text is taken from the draft executive summary.

*This state-of-the-system report reflects analysis of the Northwest’s anticipated power supply in 2015. It is meant for illustration only and is provided for the sole purpose of developing the form of the report. While the data used for this assessment is current, there remain some unsettled issues regarding resource assumptions and the hourly simulation of hydro dispatch. Thus, conclusions drawn from this report should be characterized as illustrative and are not for distribution to the general public.*

*The current estimate of the loss of load probability (LOLP) for the 2015 operating year is 0.93 percent – well below the 5 percent threshold that defines an adequate supply for the Pacific Northwest. As expected, the most critical months are December, January and August. It would take about a 2,000 megawatt peak-hour load increase (or combination of load increase and conservation decrease) to raise the LOLP to a level of 5 percent.*

*The region’s utilities take advantage of available within-region and out-of-region market resources in order to maintain an adequate supply. On average, the region purchases about 1,500 megawatt-months of market energy in December, out of a total market size of 6,600 megawatt-months (23 percent). In August, the region purchases about 600 megawatt-months of market energy, out of a total of 2,000 megawatt-months (30 percent).*

*Ten percent of the time, market purchases exceed 2,400 megawatt-months in December (37 percent of the market size) and 900 megawatt-months in January (45 percent of the market size). The percent of hours when the full amount of market resource is purchased is less than 1 percent for all months.*

*Borrowed hydro (energy below the drafting rights elevations) is most often used between July and October, with little being used during winter months. The likelihood of using borrowed hydro in August, for example, is nearly 90 percent, while the likelihood in December is only 14 percent. Borrowed hydro is used as a resource of last resort, after all available firm and market resources are dispatched. Borrowed hydro energy is intended to be used only for short periods of time, such as over a cold snap or a heat wave, and is replaced as soon as is physically possible. The maximum amount of borrowed hydro energy per month is set to 1,000 megawatt-months but, on average, very little is used. In August, the average amount of borrowed hydro energy used is about 70 megawatt-months, although in the worst August about 700 megawatt-months is used. The use of borrowed hydro does not affect reservoir refill or the ability of the hydroelectric system to maintain minimum river flows for fish migration.*

*The region also relies on standby resources – generating resources and demand side actions that are intended to be used only during emergencies – to maintain adequacy. Currently identified standby resources only contribute a small energy and capacity amount. Analysis shows that standby resources are dispatched in only 1.1 percent of all simulated years. To put this value in perspective, the LOLP would be 1.1 percent (instead of 0.93 percent) in the absence of standby resources.*

*A shortfall (curtailment) event is defined as a contiguous set of hours when resources fail to meet load. The expected number of shortfall events per year (not counting standby resources) is 0.02. The average duration for an event is 15 hours and the average magnitude is about 21,000 megawatt-hours. The average peak-hour curtailment is about 1,700 megawatts. Overall, the expected number of hours of curtailment per year (not events) is 0.3 (this often referred to at the loss-of-load hours).*

Stephen asked why the model is showing more market purchases in November than in January. John said he didn’t know but would look into it.

Steve Oliver asked what the correlation between our need and Canada’s need for market purchases. How big is the combination? Do we really have these market resources during extreme events? The answer was that we are being conservative in our estimate of market supply from California. Generally, if the NW is experiencing poor water conditions and adverse temperatures, so also is Canada. A look at some historical stressful periods may help answer this question.

An error was found on page 16, for the description of the water conditions. The percentile for hydro conditions needs to be subtracted from 100 percent in order to be consistent with the other variables. John said he would change this.

Phil commented that he thought the spinner chart, which allows a user to click through all the curtailment events, is very good for educational purposes.

John asked the steering committee members to take the draft SOS report home and review the format. He asked that comments, questions and suggestions be sent to him.

Steve Oliver said we should look at examples of other utilities’ reports and what data they provide. He also suggested that we do more comparisons of simulated to actual real world events. He said that although he feels that nobody is much ahead of us, we can always do better. He emphasized that, in the end, we have to have a solid connection with real time operators.

Tom Karier suggested that a more formal evaluation could occur after the initial SOS report comes out in the fall. We should be able to validate the results without compromising proprietary information.

John reiterated that preliminary results for the 2017 adequacy assessment should be available by July for the technical committee to review.

The following comments are from Dick Adams (PNUCC), who could not attend today’s meeting but wanted his comments discussed.

*I wanted to let you know that I will not be able to attend your Resource Adequacy Steering Committee meeting tomorrow.  Unfortunately it conflicts with our monthly System Planning Committee meeting, and I need to be at that meeting to move a couple of projects forward.  I continue to believe the work of the Adequacy Forum is extremely important, and hence I have been a regular at all of  the Steering Committee meetings and most of the technical meetings.  Alas - I will miss the discussion tomorrow.  If I were there, I would offer the following observations on the topics to be discussed:*

1. ***Sensitivity analysis should be done on key assumptions.****John will be asking for direction on several modeling assumptions including market purchases.  While his proposed numbers for in-region and out-of-region short term markets seem reasonable, I suggest that a range of values for these key assumptions be studied to determine their affect on the results (eg. affect on LOLP).  If the LOLP results are not sensitive to the assumptions, we should know that and move on.  On the other hand, if the LOLP does change dramatically to a change in market purchase assumptions (for example) then we might want to direct further analysis to refine the assumption to be used.*

***2.       Representation of Wind needs more scrutiny.*** *Integration of the variability of wind into our system is a major focus in our industry.  As we have moved from near zero to over 8,000 MW of installed wind on our system, the challenge is growing.    I would hope/expect that the Resource Adequacy Forum’s analysis would provide the region with an early warning on meeting the challenges of integrating wind.  My sense is that the current analysis uses 3-4 years of actual hourly wind generation from one geographic area, and is then scaled up to the represent all of the installed/forecast wind.  The technical committee (or consultant) should assess whether this approach is robust enough to capture the range and diversity of the wind’s expected future performance.*

***3.       Changes in Study Results (LOLP) need to be tracked and explained.****The current LOLP results appear to be below 1%.  I suggest that the technical committee (probably John) retrace our history on the results of our analysis – starting with the first one, and helps us understand how/why the results have changed.  The results need to be stable and explainable for our analysis to be credible.  While I haven’t tracked every PowerPoint and formal assessment done since the Forum was created, my sense is that the results have changed dramatically.  Are the changes due to our modeling or are the changes due to the real world circumstances?  A history lesson would help answer that question and provide some confidence in the results.*

The following comments are from Phillip Popoff, who sent these to me after the meeting.

*Just wanted to follow-up with an idea about how to define “Yellow Light.”*

*Our conversation on Friday was framed around the assumption that we need an objective definition of yellow.*

*Another approach would be to make designation of yellow a judgment call recommendation by the Steering Committee.  That is, the region’s LOLP is less than 5%, but….*

*The Technical Committee could present what it would take to drive the system to red light.  Probably best to translate it to deterministic variables people can wrap their heads around.  Examples would be in x% of the cases the region is relying on contingency resources, or if the region experiences net load growth x% greater than expected, or conservation efforts fall short by y%, or some combination--that kind of thing.  Assuming we’re in green light, at a future steering committee meeting, we could review the conditions to drive the region to red light.  Probably be a good discussion, then the co-chairs would decide whether to pass up the recommendation for green or yellow to the Council.  It would be a regionally well-vetted decision.*

*This approach specifically creates a place to apply judgment—and caution is a judgment.  There is an amazing amount of analytical horse power working on this process.  There is an equally impressive amount of experience and judgment around the table; that includes folks on the technical committee, the steering committee, and the co-chairs.  Why not rely on it as an asset?*

*Just an idea.*

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