# PNW Resource Adequacy Technical Committee
# Notes
# February 16, 2006

INTRODUCTIONS:

There were no comments or questions regarding the notes from the January 12th technical committee meeting.

SYNOPSIS OF JANUARY 24TH STEERING COMMITTEE MEETING:

Mary Johannis presented a summary of the January 24th steering committee meeting. John Fazio interjected with a summary of the Council process. The Council will vote to release an issue paper on February 22nd and public comment will be taken over a two-month period. Comments will be reviewed by both the technical and steering committees and forwarded to the Council. At its May meeting, the Council will vote to adopt the energy portion of the standard. The capacity portion will be developed by summer with a similar Council process to follow -- a release of an issue paper likely in August with a two-month comment period followed by a vote to adopt in November.

The steering committee's work on "implementation alternatives" was briefly discussed. A draft paper on this issue is close to being ready for release to both committees for comment. It will be scheduled for discussion at the next steering committee meeting.

AVISTA'S SUSTAINED PEAKING CAPACITY METHODOLOGY:

Clint Kalich presented a summary of Avista's approach to capacity assessment (http://www.nwcouncil.org/energy/resource/2006_02/0216.pdf). Clint mentioned that Avista would likely be capacity short before it is energy short. Steve Weiss mentioned that other IRP processes also show that capacity is an issue that is coming up fast for other northwest utilities.

Mary asked if Avista would run Rathdrum for market sales? Clint said absolutely, but the likelihood that market revenues would offset operating costs is very small. Clint also highlighted the fact that carrying capacity reserves is expensive.

Slide 18 of Clint's presentation assumes "cold snap" temperatures to assess loads, probably about 80 or 90 percent of the worst day. Clint indicated that he was still debating whether the line item identified as "10 percent contingency" should be included. It was added to account for forced outages and other contingencies but he suggested that forced outages should probably be accounted for directly in the resource line items.

Avista used a 90% adverse hydro condition to assess hydro. In slide 18; hydro generation bumps up from 208 to 326 megawatts, as the peak duration increases, because of the assumed time lag of Coulee's cold snap operation. BPA planners had indicated in a previous meeting that the time lag might not be applicable since BPA would likely have already set up the FCRPS to increase generation at the Lower Columbia Federal power plants.

Avista feels comfortable that there is plenty of capacity for gas transport. This committee is still waiting to hear from Terry Morlan and the gas advisory group on this issue.

Avista has been disappointed with Stateline wind in its inability to deliver during cold snaps. Clint suggested that Montana wind would be much more useful for Avista primarily because of different wind patterns. In this presentation Avista included no peaking capacity from Stateline wind but would likely show some values in future versions. Clint thinks a 10% assumption might be appropriate and he added that the peaking value for wind should be a function of the sustained peaking duration.

Avista has no interruptible load contracts today but may consider such types of contracts in the future.

Avista would like more information regarding how the federal system would operate during a cold snap because of its effects to Avista's hydro capability.

Someone asked if this approach would be used for Avista's IRP process? Clint said that right now Avista is still using a 1-hour peaking number but it will likely move to a sustained peaking number. Avista has the same software platform that runs "Columbia Vista" for BPA, but they still consider the spreadsheet approach to be very useful. Avista uses other models to either develop values included in the spreadsheet, or to confirm assumptions included in it.

Someone asked if Avista takes transmission outages into account when planning for bad weather? Avista does not. The group agreed that it really shouldn't be counted, but it does happen.

How did Avista arrive at the decision to use a 90% adverse hydro level? Clint said that it was a just a starting point and that there was no formal process to assess the value.

Clint said that state regulators were interested in Avista's spreadsheet approach but did not push to make it required for the 2005 IRP. This concluded Clint's presentation.

REGIONAL CAPACITY METRIC & TARGET METHODOLOGY:

Mary asked for volunteers to present their company's efforts to assess capacity needs. There were no immediate takers but Rod Noteboom said that Grant PUD is quite concerned about the capacity at Priest Rapids. He said that non-power constraints must be included in order to accurately assess the capability. The biological constraints at Priest are complex and affect Grant's capacity significantly.

There was a brief discussion of emergency operations in which Mary indicated that the not-often-used Emergency Response Team should still be a viable process during cold snaps. The group thought it would interesting to check on the status of that group even though that process may be outside the scope of the resource adequacy forum.

Mary made her presentation on methodologies for capacity assessment (http://www.nwcouncil.org/energy/resource/2006_02/021606.pdf).

Steve Weiss asked if doing a capacity assessment was meaningful at all since we take capacity into account in the LOLP calculation and in the corresponding energy metric and target. John responded that it is likely that the capacity metric will not be the binding constraint however; we should calculate it just to make sure.

Dick Adams suggested that this committee should look at all sustained peaking durations rather than trying to find the “right” one (i.e. do what Clint did in his spreadsheet). The group generally agreed. Dick also had some concern regarding the wording of the second bullet on slide 2 of Mary’s presentation.

Chris Robinson commented that asking for capacity data might require some form of confidentiality agreements, unless the data is aggregated into a regional assessment and only shown in this form. Mary suggested that the Council could be the depository for this data instead of BPA. The committee generally felt more comfortable with this option. Clint added that he hoped that policy representatives would loosen up a bit in regard to this issue because most of the data is available in some form or other anyway. The technical committee will forward this issue to the steering committee for resolution. But, Dick suggested that we already have a process for doing this (at least for the energy side of things), so it may be a non-issue. Mary thought it would still be a good idea to discuss it at the steering committee.

The committee decided that “option 2” (slide 6 in Mary’s presentation) would likely be the best for a capacity assessment process. That option would have the Council collect data and then aggregate it and make a sustained peaking assessment.

Continuing her presentation, Mary suggested that it would be useful to compare the capacity assessment for a worst case (cold snap) to a normal-weather case in order to help determine what part of the target (reserve margin) should be attributable to weather.

The committee reiterated the idea that it would be beneficial to look at peaking capabilities for different sustained peaking durations. Someone asked whether the Genesys model was capable of providing this type of analysis. John responded by saying that Genesys has information for 2-hour, 4-hour and 10-hour peaking durations. However, he added that that data needs to be updated along with other data related to hourly demand assessments. The summer relationship between temperature and demand, in particular, should be updated because the current relationship is based on 15 year old data and it is very likely that air conditioning penetration rates have increased substantially since then.

The committee decided that loads from February of 1989 should be used for the worst-case scenario.  John suggested that we also look at a high-temperature worst-case scenario and he will review likely candidates.

A question arose regarding the assessment of the peaking capability for the mid-C projects.  Rod suggested that we use historical generation as an indicator.  John replied that it might be more appropriate to observe historical elevations so that upstream peaking operations are screened out.  Rod replied that elevation changes at the mid-Cs do not always reflect peaking operations, but often are driven by fish constraints.  He added that Priest Rapids, for instance, does reverse load factoring (to provide salmon spawning protection).

For most run-of-river projects the committee agreed that it should use installed capacity and the capacity factor over the specified peaking duration.  But individual utilities should provide more data when and if available.

The committee should develop a specific list of data requirements for utilities to provide regarding hydro (and other) resources.

Getting back to the issue of the worst-case scenario, Wally Gibson suggested that we use critical water (or close to critical water) along with cold temperatures for that assessment.  The committee agreed to use February 1989 temperatures with 1937 hydro conditions for this case.

A question came up about the capacity of thermal resources during cold weather.  Gas-fired capacity would increase in cold temperatures due to efficiency gains but coal generation may be affected due to fuel freeze-up issues.  Someone suggested that these two effects might cancel out and therefore we could ignore this effect.  I believe the group agreed that in the first pass, the worst-case scenario would not include these adjustments.

Getting back to a more general question regarding the entire process, Steve Weiss asked whether there might be some opportunity for “gaming” by utilities when providing data for this assessment.

[This paragraph reflects thoughts that I had during this discussion but was not able to raise due to time constraints.  However, I feel that these issues are important enough that they ought to be recorded and discussed at some point.]  We may want to allow maintenance to be deferred during a problem period for both the spreadsheet calculations and the Genesys (or other model analyses).  For the Genesys analysis, this would require a modification to the code.  Also, we should consider whether Genesys (or the spreadsheet method) should curtail bypass spill during emergency situations.  This needs to be discussed further.

The committee decided that typical force outage rates would be used for the spreadsheet calculation and in Genesys.

After some discussion, the committee agreed that wind peaking capacity should be zero for a single hour duration but then ramp up to 20 percent for a 50-hour duration. Steve Weiss suggested that this committee review Pacificorp's work on this issue.

The next question Mary raised was how to deal with transmission constraints. John pointed out that utility IRPs must somehow deal with transmission and that we could ask utilities for help in this area. It was pointed out that Idaho Power faces many transmission constraints and would likely have much experience on this issue. John then suggested using some kind of a "de-rating" process to account for transmission constraints when assessing the peaking capability for the entire region. But he went on to say that transmission might very well be beyond the scope of the adequacy forum and that there are other groups looking into the matter. For the time being the committee agreed to assume that all regional generation could get to all regional loads, that is, ignore the effect of transmission.

A summary of the agreed upon assumptions will be made available to this committee (and to the steering committee). A prototype spreadsheet model should be developed for the regional assessment of peaking capability. The candidate for the "calibration" model is still being discussed. While the Columbia Vista and HOSS models might be viable, data or logic upgrades would have to be made. However, because Columbia Vista is a proprietary model the committee thought that it should not be a likely candidate. HOSS would be a logical choice but it would require quite a bit of updating -- something that BPA is not currently planning to do. That leaves the Genesys model as a possible candidate. John will evaluate whether Genesys is capable of provided the appropriate analysis and if so what updates would be required.

NEXT MEETING:

Next meeting is scheduled for Thursday March 9th from 9:30 to 2:30.

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