**Resource Adequacy Forum  
Technical Committee Co-Chair Briefing  
Meeting Notes**December 08, 2010

The Adequacy Forum’s Technical Committee co-chairs John Fazio (NWPCC), Rob Diffely and Birgit Koehler (BPA) met with Pat Byrne, Steve Kerns and Kristine Bartlett (BPA) and with Dick Adams (PNUCC) and with Gwen Shearer (contractor) on December 8th. These notes are based on my memory of this meeting and may not be comprehensive. If you participated in this meeting and find omissions or errors, please send revisions to me (<mailto:jfazio@nwcouncil.org>).

**Wind Study**

The meeting began with a discussion of the “big wind” study being done jointly by the Council and PNUCC. The intent of the study is to estimate wind’s load carrying capability and its effects on overgeneration and non-hydro resource dispatch.

*Results discussed at this meeting are preliminary and are not meant for distribution.* They show an average wind effective load carrying capability (ELCC) of about 22% for the current system, which includes about 3,100 MW of wind capacity serving loads in the PNW. The ELCC is a narrowly defined variable that identifies how much wind capacity (in MW) is required to serve an incremental annual load (in MWa) without changing system adequacy. John ran these studies using the GENESYS model for the 2015 operating year using existing resources only and expected new conservation (implicit in the Council’s short-term load model). His “base” case removed all wind resources. Study cases included increments of new load (shaped) and wind.

The method used to assess wind ELCC involves recording the adequacy of the power supply for the base case, then adding increments of load and wind until the study case’s adequacy returns to the value observed in the base case. John first tried to use LOLP as the metric for adequacy but quickly discovered that it was too “blunt” a measure. He subsequently decided to use a more sensitive measure, namely, the total average curtailment per simulation (in MW-hours).

Results of John’s studies show average wind ELCC starting at a little over 25% and declining to about 15% at 8,000 MW of installed wind. The incremental values drop from 25% to under 4% for the same amounts of installed wind. Currently, the system has about 3,100 MW of wind devoted to NW loads, and the current incremental ELCC for wind is in the range of 15%. That means that adding 100 MW of wind generation to the current supply would allow us to add 15 MWa of new load and maintain the same level of average curtailment.

John said that preliminary results for average ELCC (about 22%) for the current amount of installed wind was close to values being discussed at by BPA for inclusion into its White Book publication. Birgit emphasized, however, that the numbers being similar was just a coincidence because BPA’s estimates were made examining wind data only, whereas John’s values were the result of a simulated dispatch.

Steve Kerns then asked if we had results on a monthly basis. John said he had not done a monthly analysis but that the output data contained monthly results. The studies focused only on the months of December through February and July through September. They were run over 70 simulations with water conditions and temperature in lockstep and thermal resource forced outage and wind as random. Steve thought it would be good to estimate the ELCC for each month separately. John said that could be done using the existing output and would send a copy to BPA staff for review.

John emphasized that there is a lot of refinement yet to do for this work. First of all, these results are highly dependent on the wind data used, which is a set of 40 synthetic “wind years” (hourly wind capacity values) developed by BPA to represent the output of the BPA fleet. This data is not temperature correlated and thus, could produce optimistic results.

Secondly, the BiOp data used in this analysis is no longer current and should be updated. Kristine added that the simulated monthly operation associated with the new BiOp data is better coordinated with real operations, especially during the January to April period when several federal reservoirs are targeted to fill to flood control levels (to hold water for later flow augmentation). John said he had received the new data from BPA and would begin to process it, which includes reassessing the “hydro peaking capability vs. monthly energy” tables.

John also mentioned that the hydro shaping logic was still under review and would likely change, although he thought those revisions would not have a significant impact on wind study results.

The group thought this would be a good agenda item for the next technical committee meeting.

**Overgeneration and Wind**

John then presented results of preliminary work on quantifying the relationship between light-load hour overgeneration and installed wind capacity. John began with the base case (no wind), which already had a significant amount of overgeneration, and added increments of load and wind so that a constant level of adequacy was maintained. For each increment of load and wind, John then calculated the total average amount of incremental (over the base case) overgeneration. The results show a rather linear increase in overgeneration as a function of increasing wind capacity.

John then reran the studies beginning with the base case but adding only wind increments (no load), which results in better adequacy (i.e. lower curtailment). These results show a larger increase in overgeneration as new wind is added (a very intuitive result since light load hour loads remain unchanged).

Steve again asked if these results could be done on a monthly basis. John said the data was readily available but only for the months of December through February and July through September.

[**John’s note**: It was not mentioned specifically at this meeting but the most sensitive months for overgeneration are those during the peak runoff, namely March, April and May. When these studies are rerun, these months should definitely be examined. The only potential problem is that March tends to be the month that is assumed for most thermal resource maintenance, thus potentially exacerbating the overgeneration problem in that month.]

This topic will be added to the agenda for the next technical committee meeting.

**Borrowed Hydro**

Next we discussed the use of “borrowed” hydro. BPA’s concern is that the model is too optimistic regarding its use (water below the drafting rights elevation). In fact, Steve Kerns suggested that “borrowed” hydro should be defined as any water drafted below the refill curve elevation (not the drafting rights elevation). We had a brief discussion about this, which included the observation made by Steve that reservoirs are usually not drafted below the refill curve during the January through April period because of operators’ desires to get to flood control elevations by April. John remarked that this approach essentially eliminated most of the hydro’s flexibility during that time. Steve agreed.

Rob asked if John could run some studies using 1,000 MWa of borrowed hydro (below PDP) out of Coulee to see how that operation would affect April refill and Chum flow requirements. John said that impacts to Chum flow requirements would be tough to assess because the hourly simulation in GENESYS is done for the hydro system in aggregate, i.e. it doesn’t provide hourly flows at specific projects. He said, however, that we could possibly estimate the hourly flows at Bonneville by “calibrating” them to system generation. That relationship, between hourly flows at Bonneville and system generation, could be defined using BPA’s hourly model (HOSS). April refill impacts are easily assessed because they represent the end-of-period elevations and GENESYS records that.

Rob was interested in breaking up the borrowed hydro blocks into two pieces; with one piece defined as a specified amount out of Coulee only and a second piece as an additional amount out of Coulee and other federal projects. John said this would be difficult to model but would look into it further.

Gwen asked if the borrowed hydro user input should be in units of energy (which is how it’s defined currently) or capacity, which would limit the amount of additional energy available in any given hour. We had a short discussion of this with no resolution. The current input for borrowed hydro is in units of MWa and defines a monthly limit on its use. This input does not specify hourly limits, which are derived from the “capacity vs. energy” tables. Examination of simulated hourly dispatch results shows that when 1,000 MWa of borrowed hydro is input, over 2,500 MW of borrowed hydro is dispatched in some hours. We decided this topic should be explored further.

John thought issues surrounding the use of borrowed hydro would be the most difficult to resolve and therefore would represent the “critical path” in terms of completing a reassessment of adequacy assumptions (the others being contingency resources and out-of-region spot market supply).

This will be added to the agenda for the next technical committee meeting.

**Contingency Resources**

The next topic for discussion was a summary of BPA’s work to quantify “contingency resources” for the region. These are resources that exist and can be used during times of stress but are generally not declared in utilities’ planning reports. These resources include backup generators at data centers and other sites, demand curtailment agreements and pumped storage generation from Banks Lake. The total energy available from these resources is in the range of 800 to 900 MWa and the peaking capability ranges from about 1,100 MW in winter to about 1,800 in summer. (Currently the energy threshold is set at 28,000 MW-hours for both winter and summer, and the capacity threshold is set to 3000 MW.)

Dick Adams asked if these resources would be added to the GENESYS model explicitly. John said probably not because of the difficulty in properly characterizing them. He anticipates that as an alternative, the curtailment record output would be screened using these resources to identify “true” curtailment events. Dick suggested that we should only use the “capacity” value of these resources to screen events and that we should monitor frequency of their use. In other words, he was concerned that we might “dispatch” these resources too often or at least more often than utilities would want. John agreed and suggested that future adequacy metrics could be two-tiered; the first metric would measure the frequency of contingency resource dispatch and the second would measure true curtailments.

It appears that this data is almost ready for review by the full technical committee and will be on the agenda for its next meeting.

**Hydro Shaping Logic**

Next Gwen described the work she has been doing on the hydro shaping logic. One issue related to this topic is the dispatch of borrowed hydro. We have observed that borrowed hydro is dispatched even if the user inputs a zero amount available. This is because the model will not allow hydro generation to fall below the minimum night-time values (related to wind DEC requirements). This “extra” nighttime generation is not compensated for by reducing on-peak hydro generation, thus increasing the monthly average generation.

Theoretically, if all the data were consistent, the hourly shaping logic would never have to drop hydro generation below the minimum level. However, the hourly dispatching logic in GENESYS is quite complex and is driven by many constraints. Gwen said that part of the problem (at least for the regional analysis) is that the west and east sides are split. She suggested that for the shaping logic, the east and west should be aggregated. John agreed that this option should be tested.

Whether Gwen’s suggestion will fix the problem is yet to be seen. If it does not solve the problem, a potential remedy would be to reduce hydro *peaking* capability when *nighttime* generation is limited to the minimum (i.e. it keeps the area under the hourly hydro generation curve constant for the month). While this would eliminate any borrowed hydro from being dispatched, it might be discounting hydro peaking capability too much. The hydro peaking values (for specific amounts of monthly hydro energy) are assessed already using the DEC requirements. If these peaking values are further reduced by this proposed remedy, we might be overly pessimistic about the hydro’s peaking capability.

John added that there is no direct connection between the simulated monthly and hourly dispatches. More precisely, when the monthly dispatch is assessed, the model does not know about hourly load shapes and other hourly constraints. John suggested that if the model dispatches borrowed hydro (when the user inputs a zero limit) it may mean that the monthly dispatch could have provided a little more energy so that hourly hydro generation could be better shaped to load. He said that the current monthly dispatch is limited by end-of-month PDP elevation constraints, which could be somewhat arbitrary (i.e. it may be possible to deviate from them as long as it doesn’t affect April refill probability). As an example, he suggested that there are many ways to get from January 1st elevations to April flood control elevations besides following the VECC/fish refill curve path. Adhering to that path may not be the most economical approach, although deviating from it may increase the likelihood of not fulfilling fish requirements.

John would like to investigate this further but given the operator’s concern about meeting fish requirements, we decided that Gwen should first test her suggested change (i.e. combining east and west in the shaping logic for regional studies) before we discuss this further.

A summary of work in this area will be added to the agenda for the next technical committee meeting.

**Peer Review**

We briefly discussed the status of the peer review of the adequacy methodology (PSRI contract). A second draft is expected within a week. Forum members will have about a month to review it and offer a final set of questions, comments and suggestions to PSRI. Mario Pereira (PSRI) is expected to meet with committee members in Portland sometime early in 2011 to discuss the report and to answer any remaining questions. It is anticipated that the report will suggest adding a measure of magnitude to the assessment methodology.

**User Interface and Production Model**

Pat Byrne informed the group that BPA is expected to have a revised user interface for the GENESYS model completed by the end of the 2011 fiscal year. The process consists of two phases, with the first phase to update the current interface to include new files and user options and the second phase to move to a “.net” environment. John added that he is expecting that all refinements to the dispatch logic in GENESYS will be completed in this fiscal year and that a production version of the model (including the user interface) should be available by September of 2011.

**Wind Data**

Birgit briefed us on the status of the development of temperature-correlated wind data for the BPA fleet. Ben Kujala (BPA staff) was working on this data set but is now in a different position at BPA, effectively putting this work on hold. There is no expected completion date. John said it is important for this work to be completed but in the meantime, the current data set could be modified to show some correlation between wind and temperature. He suggested, for example, that under extreme temperature events, wind generation could be set to zero (in the model), thus providing a “bookend” result. The current data provides an optimistic value for wind ELCC (because it is not correlated with temperature) and the modified data would provide a pessimistic value for ELCC.

**Federal Study Transmission Losses**

Rob and Gwen briefly discussed an issue of surrounding transmission losses as reported for federal studies. For regional studies, transmission losses are incorporated into the load forecast.

**2011 Work Plan**

We briefly discussed the Adequacy Forum’s work plan for 2011:

February - resolution of assumptions (borrowed hydro, contingency resources)  
March - reassessment of adequacy using revised assumptions  
April - technical committee proposes revisions to standard based on peer review  
June - steering committee votes on revision  
August - Council votes on new standard  
October - reassessment of adequacy using new standard

Dick suggested that this work plan was probably too optimistic. He thought the committees would need more time to digest the peer review report and to develop more defendable assumptions. In particular, he was worried about how the threshold for adequacy (currently the 5% LOLP limit) would be derived. The co-chairs agreed and decided that the work plan should be revised to allow more time for discussion and resolution of these issues.

A discussion of the work plan will be added to the technical committee’s agenda.

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

q:\jf\ra forum\2010\120810 co-chair brief notes.docx