At the November 16, 2007 meeting of the Wind Power Integration in Ontario working group, members were asked to submit comments on the wind capacity contribution calculation methods for mid-term forecasting.

Two written comments were received as summarized below along with the IESO response.

**Tom Adams**
I wish to register some comments on the agenda item #5 and the associated discussion material posted to the WPIWG site.

1. I note that in the “18 month” outlook issued in September there is the following two comments:

   "The IESO is developing monthly assumptions for wind capacity contribution and will incorporate these once stakeholder review has been completed near the end of 2007."

   "IESO is examining wind issues with stakeholders in the Wind Power Integration Working Group (SE-29). The assumed capacity factor at the time of the peak is an issue this stakeholdering process will address in the near future."

2. No reference to wind capacity contribution was noted on the agenda, so unless parties opened the presentation slides for Mid-term Forecasting they would not realize that the matter was being addressed.

3. Slide 5 of the above noted presentation refers to the AWS assessment. A key point missing here is that the AWS assessment was based only on simulated generator output. I note that of the wind farms in Ontario with a capacity of 10 MW or above, only one has achieved an average capacity factor at approximately the expected annual output (Kingsbridge). A similar pattern has been noted for 12 of the 14 WIPPI projects across Canada as of October 2006. Given the track record of the wind industry and its consultants with respect to the accuracy of forecasted production, I suggest that it is important to distinguish between real and simulated generator output and to rely on real information wherever possible.

4. Slide 8 indicates that the IESO has access to actual performance data for January and July 2008, which appears unlikely. Your analysis indicates that in July, 50% of the time wind output is equal to 18% of the nameplate. Since you now have actuals for Jan. 2007, and July 06/07, I recommend that these be considered. I performed this analysis based on the actuals for July06/07 and found that 50% of the time wind output in July has been equal to 10% of the nameplate. Wind output in July 06/07 only exceeded 18% 29% of the hours, not 50% as the IESO has claimed. Please correct me if I am wrong.
5. For estimating the future winter capacity contribution, I recommend inclusion of a temperature vs. wind output correlation. Our research indicates a large positive (i.e. unfavourable) correlation between winter temperature and wind output (15.9% during the winter ‘06/’07). This only represents one year of experience however similar result have been found in the UK using several years of data. Lower expected wind output on colder winter days does not appear to be a factor considered in the IESO analysis presented in your slides. Please correct me if I am wrong.

6. I have recommended to the WPIWG several times that actual data from wind farms in neighbouring jurisdictions be used to help assess issues such as the stabilization of output that might arise from geographic diversification. Your presentation contains no hint that the IESO has utilized this suggestion. Our research indicates that average summer capacity factors across Canada are similar to those found in Ontario i.e. below 20%. This suggests that geographic diversity provides limited gains for output stabilization during the Ontario peak demand period.

7. The “monthly/seasonal” option that you offer on Slides 7, 10 and 11 appears to be assuming that the monthly average capacity factor will equal the monthly average capacity contribution. Given the frequency, particularly in summer, of periods of 24 hours or more of total wind fleet output of less than 5% of CF, I suggest that a more cautious, probability weighted criterion should be used. Perhaps a 75% confidence interval might be explored as an alternative.

I have two questions:

8. Please indicate the source of the “actual” data presented in Slide 8.

9. The final slide indicates “Continue to explore, streamline and finalize forecasting options”. I hope and assume that this comment indicates a continuing role for the WPIWG in this development. If I am wrong about this, I would appreciate notice of where this exploration, streamlining and finalization steps are being conducted.

**IESO Response**

1. IESO has updated the information in its latest December 2007 - 18 Month Outlook.

   [http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2007dec.pdf](http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2007dec.pdf) See the revised wordings of latest 18-Month Outlook as quoted below:

   Re: section 3.2: “The IESO is developing monthly assumptions to forecast wind capacity contribution that will consider the actual wind data and will incorporate these in future Outlook forecasts once stakeholder review has been completed in the near future.”

   Re: section 5.4.6: “IESO is examining wind issues with stakeholders in the Wind Power Integration Working Group (SE-29). The assumed capacity factor at the time of the peak is an issue this stakeholdering process will address in the near future.”
No reference to wind capacity contribution was noted on the agenda, so unless parties opened the presentation slides for Mid-term Forecasting they would not realize that the matter was being addressed.

2. We agree. The related agenda title of February 20 Wind Power Standing Committee now notes as follows: Mid-Term Forecasting Requirements: Wind Capacity Contributions Methodology.

3. We agree. The forecasting options and methods proposed for the 18-Month Outlook now incorporate the lesser of the actual wind output and simulated wind output. Furthermore we continue to examine other approaches used by system operators and utilities across North America.

4. This was an error. The “Actual Data” refers to the simulated historical data used to generate the WCC assumption for the months of January and July 2008. The term “actual” was used erroneously to distinguish the curve from the “best fit” curve. We will revise it.

5. Our actual performance reflects winter temperatures and our simulated data would reflect a broader range of temperatures. Since our demand forecast is based on normal weather and our simulated history should approach that, we feel temperature correlation is adequately addressed. We will consider temperature impacts on wind output under extreme demand weather conditions and will advise the Standing Committee of any findings and stakeholder any future process changes with the group. With passage of time and availability of more historical actual records and variables, we would continue to explore and make improvements in methodology, as applicable.

6. We feel that output stabilization is not relevant to the Outlook capacity contribution issue, but is an issue that the IESO is examining since it affects real-time forecasting and operations. There are a number of initiatives in early stages which we plan to explore and which may be able to capitalize on geographic diversity. We will take into account your comments and your input in this area when we set about addressing this issue.

7. Based on your first sentence, there may be some misunderstanding of our approach. We make no assumption about monthly average capacity factor (an energy quantity based on all hours of the month) being equal to the monthly median capacity contribution over peak hours of the month. The approach we have selected should result in an equal probability of being over or under the value used in each month. This approach is already used for demand, forced outage rates and hydroelectric production. Working with median outcomes is an approach widely accepted across the continent and by NERC. We are actively engaged in several industry forums to explore various options for determining wind capacity contribution and will continue to bring these to the standing committee at the appropriate time.
8. This was an error and it will be corrected. The “Actual Data” refers to the simulated historical data used to generate the WCC assumption for the months of January and July 2008. The term “actual” was used erroneously to distinguish the curve from the “best fit” curve.

9. As an action item (re: minutes of November 16 meeting), we have requested the Wind Power Standing Committee (formerly WPIWG) members to review different capacity contribution methods and options presented in our November 16 slides and send their comments to IESO by end of January, 2008. Final refinement of the proposed methodology is expected during the February 20 Wind Power Standing Committee meeting. Beyond that, we expect to continue to examine various aspects of mid-term forecasting as industry experience with wind continues to evolve.

Rob Cary

I’m pleased to follow up with a few brief comments arising during the meeting yesterday and in subsequent consideration.

**Mid term forecasting: months 1 to 18.**
- I am supportive of the use of summer and winter values, supplemented by monthly phasing from one to the other. This is a rational approach based on the best available information.
- The use of critical hour values seems appropriate.
- You raised the question of how to reconcile the simulated 10 year values with the actual results to date. You might want to consider the using for the 4 summer months the median of all actual summer months and the median simulated values for each of the four summer months. This would naturally increase the weighting of actual results as you get more data.

**Near term forecasting: days 1 to 33.**
- The demand forecast basis of SAAs varies within this period. On consideration following the meeting, I would suggest that the wind forecast basis mirror the basis of SAA demand forecasting.
- For days 14 to 33, I understand that the daily demand forecast is based on the same data as those used in the 18 month assessment. There is no attempt to make data weather-specific. The assessment includes allowances to cover the uncertainty of the forecast. It therefore seems only rational to use the same wind capacity values as in those assessments. Looking at the summer daily profile presented in the meeting, this looks reasonably in line with the values to be expected during the daily peak demand hours. And in winter, this looks like it would produce a slightly conservative result in the typical peak demand hours. You could consider using weekly interpolation of values in the shoulder seasons, but this may or may not be material.
- For days 1 to 10 (?), I understand that the hourly demand forecast is based on specific weather forecasts, and the hourly values are thus more meaningful. I would strongly suggest that you adopt the hourly pattern of median capacity factors for this forecast period. It does not make sense to apply a 9 am minimum value to the mid afternoon peak demand period. You should probably adopt the same interpolation approach for the shoulder months (or weeks).
For days 11 to 14, even though the SAA is nominally on an hourly basis, I understand this to have little more specificity than for days 15 to 33. I would suggest that this therefore be aligned with the 11 to 33 methodology, but you could elect to align it to the 1 to 10 methodology.

Within days 1 to 10, you should give consideration to the interaction between wind capacity expectations and hydraulic energy limits. On an intuitive basis I expect that there would be no issues with this if you do adopt the hourly profile approach, but it might become an issue with flattened approaches.

**Day ahead forecasting**

- We did have some discussion of forecasting in the context of a day-ahead market. I suggested that you might want to consider how participant forecasts should interact with IESO forecasts. You might for example want to use the IESO forecast based on the near term methodology suggested above as the basis for reliability-based commitment schedule, and use the participant forecasts for the UDAM schedule.

- This is presumably an issue that has been given consideration in the DACP. It would be interesting to hear how this is handled in this context.

**Real time forecasting:**

- Brookfield’s presentation was useful and informative.

- Has the IESO given consideration to the period 3 to 5 hours ahead? The two hour forecast presumably covers the period within which intertie commitments are made. It does not cover the period within which generator commitment decisions are being made. The IESO might want to find a methodology to update in some way the 3 to 5 hour ahead data. For instance a reduction of the hour 14 forecast from 200 MW (day ahead forecast) to 100 MW (2 hour ahead forecast) might be assumed to have a 75% impact (eg moving the forecast from 200 to 125 MW) in hour 15, a 50% impact (e.g. moving the forecast from 200 to 150 MW) in hour 16, and a 25% impact (e.g. moving the forecast from 200 to 175 MW) in hour 17. Clearly the actual rules would need to be a little more sophisticated than this. If a participant actively updated the forecast for those later hours, that would over-ride any such IESO adjustments. But if the IESO adopts a standard for two-hour look ahead by participants, then the IESO would need to consider those next few hours.

I hope these thoughts will be helpful in the ongoing work of the IESO and the WG/SC.

**IESO Response**

**Mid term forecasting: months 1 to 18.**

The IESO has factored in actual wind output data for the 3 summer months from 2006 and 2007 as well as compared it with medians of summer simulated wind model values in response to stakeholder input. A methodology for including actual wind output data and incorporating it into the Wind Capacity Contribution calculation of median values and associated probability distributions was presented and agreed upon during Feb 20, 2008 standing committee meeting.
Near-term forecasting: days 1-33
The IESO did look into the trade offs of using the variable hourly median capacity value versus the flat trend. The assessment, which is shown Slide 6 of the linked presentation
http://www.ieso.ca/imoweb/pubs/consult/windpower/wpsc-20080220-Item5_NearTermWind.pdf, showed an insignificant difference when looking at the average magnitude of over forecast/under forecast amounts. (The average forecast error line graphs in blue represent the varying hourly trend, while the orange are based on the flat trend).

Although the practice of using the daily minimum tends to increase the under forecasting frequency through out the day, the two trends tend to have similar results. The difference seen in the graphs have minimal operational impacts, with a significant trade off in simplicity of using the single seasonal value method. With the manual nature that will be used to add wind contributions to intermittent entries in SSR’s and SAA’s. The IESO will proceed with the use of the flat trend forecast, until a time when a more automated process can be implemented that will facilitate the use of individual forecast variable for each hour per season.

Day-Ahead Forecasting
Thank you for your comments. They have been passed over the Day-Ahead Market team for their consideration under that initiative (SE21)

Real-time Forecasting
Centralized forecasting requirements were discussed with the wind working group and it was agreed that current levels of forecast errors and wind penetrations do not necessitate a centralized system at this stage, if MPs desire they can choose to pursue such option via third party forecaster services. We also agreed that this option or recommendation may be re-visited in future upon outcome of associated cost and forecasting studies. In the meantime, as per IESO rule/market manual requirements the MPS need to provide and update forecasts as soon as practically possible