<u>Stakeholder Comment & AESO Response Form</u>

2008 Loss Factors
December 11, 2007

Date of Comment: October 25, 2007
AESO Response: December 11, 2007

AESO 2008 Loss Factors

Response to a letter from HR Milner (J McCormack) on October 25 2007

HR Milner Concern	AESO Response
1. Milner is concerned that the new Valleyview and Northern Prairie power generators appear to have been added to the GSO as base loaded generators rather than peaking units. Both of these generators are gas generators. The GSO shows that the historical output from other gas generators in the area is a relatively small fraction of their STS capacity. In the case of Valleyview there is an existing generator owned by ATCO power of a similar size and type at the same location. The GSO shows that historically the average output of the existing generator has been less than 2.5 MW in all of the scenarios used for the Loss Factor calculations. However, the new generator at Valleyview is included in the GSO producing 40.7 MW in all hours after it is commissioned. Similarly the proposed Northern Prairie power generator is shown as producing 86.6 MW in all hours following commissioning. These new generators are located in an area where loss factors are very sensitive to generator output. In Milner's case the 2008 loss factor has increased over 4.4% from a credit to a significant charge. Other NW generators are also significantly negatively impacted. In situations such as these it is critical that the modeled power production from new generation be adjusted to produce a realistic dispatch in line with the historical output of other similar generators in the area.	**The AESO has made a commitment to employ rules and processes to determine loss factors that reduce its level of judgment. In particular, the use of historic generation rather than forecasts assists us in meeting this commitment. Under the current loss factor rule, new generators are also subject to a specific process, since no historical generation is available. In the case of gas peaking generators, the AESO acknowledges that result of new generator process did not produce a reasonable result and so we have recalculated the 2008 loss factors.** **For further clarity, the same "new generator" process was used in 2006 and 2007 loss factors calculations and stakeholders did not raise objections.** **Finally, the other similar generators in the area are subject to dispatch under TMR contract and the new units are not. The AESO has recalculated 2008 loss factors based on historical values of similar generators unencumbered by contract TMR dispatch constraints.**
Please provide the generator loss factors with the generation MW output from the new Valleyview generator, set to the same values as the historical MW output of the existing Valleyview generator and the MW output from the new Northern Prairie Power generator modeled so that the modeled MW output as a fraction of MCR capacity is similar to the average in-merit output	**See response above**

as a fraction of MCR capacity of the existing area gas fired generators. Historical and forecast TMR dispatches from area generators should not be considered when assessing the ratio of in merit dispatch to MCR capacity.	
2. On July 25, 2006 the AESO posted a summary of the 2006 loss factor meeting notes and actions. In these notes the AESO indicated, *"The TMR generators' actual historical outputs consist of two components – the energy market and the TMR component. For the purpose of GSO preparation the AESO removes the TMR component from the total historical output and uses the energy market component only as the historical output. TMR is shown separately."* TMR is only dispatched when the required generation is not in merit. In the Rainbow area, TMR can be provided from Rainbow 1, 2, 3, 5 Rainbow Lake 1 and Fort Nelson generators. The 2008 GSO shows there were historical in merit dispatches for Rainbow 1, Rainbow 2, Rainbow 5 and Rainbow Lake 1. While these dispatches appear to be small it must be remembered that the GSO numbers represent average dispatches. In reality, these units would have been dispatched to higher levels for a few hours and dispatched at zero in other hours. When they were dispatched to higher levels and were in merit, the need for TMR would be reduced. To capture this, the forecast requirements for TMR in the GSO should be reduced by the amount of in merit dispatch from all area generators who are eligible to provide TMR. In the Grande Prairie area, the 2008 GSO indicates TMR is forecast to be provided from Bear Creek G1. However, TMR can be provided from Bear Creek G1 and G2, Valleyview, Poplar Hill, Grande Prairie EcoPower and Northstone Power. The 2008 GSO shows there were historical in merit dispatches for all of these generators. When these generators are operating in merit, the need for TMR is reduced. As indicated above, to capture this, the forecast requirements for TMR in the GSO should be reduced by the amount of in merit dispatch from all area generators who are eligible to provide	**In reality, when generators that have a minimum dispatch for TMR and subsequently the un-dispatched capacity becomes in merit, the TMR capacity is not removed from the system, so removing it from the cases would not be appropriate. The cases are developed recognizing the TMR and energy market components.**

TMR. Obviously TMR dispatches cannot be negative. If the historical in merit generation from generators eligible to provide TMR negates the need for TMR the TMR forecast should be reduced to zero. Please provide the generator loss factors with the forecast requirements for TMR in the GSO reduced by the amount of in merit dispatch from all area generators who are eligible to provide TMR.	
3. The notes from the October 24, 2006 loss factor stakeholder meeting show that in response to a request to describe why the NW enhancements are not in the 2007 loss factor base cases when the need assessment called for a 2007 ISD the AESO indicated, *"The latest information on the project indicates the NW project will not start to enter service until late 2007. The 2008 cases will start to reflect new equipment in service."* What NW transmission enhancements, that were included in the approved NW need application, are now included in the 2008 loss factor base cases?	**The changes in the modeling for 2008 are consistent with TASMo (on the AESO web site) and within the '.sav and rawd' cases for 2008, also on the AESO web site. Based on the data available, the transmission changes are small.**
4. At the recent loss factor stakeholder meeting, the AESO was asked if it could provide the system load in each of the 12 scenarios used to calculate the 2008 loss factors. Could the AESO please provide:	**Please note: the AESO makes a concerted effort to provide data in the base cases (sav and rawd), in the submissions to our web site, and also in the meetings. Much of the data requested below is available in these forums.**
Which cases, if any, was the load scaled?	**Ten of twelve.**
What the unscaled load was in each of the 12 cases used to calculate the 2008 Loss Factors?	**The AESO has provided the load forecast confidentially to stakeholders in the loss factor process.**
what the scaled load was in each of the 12 cases used to calculate the 2008 Loss Factors	**This information is in the base (rawd) cases.**
The hourly forecast of load for 2008 used by the AESO	**Please see above. The hourly numbers cannot be published as the AESO need to approve a process for publishing them.**

5. Previously, the AESO has provided a table showing for each generator, the loss factors for each of the 12 load scenarios used to calculate the annual loss factor. Could the AESO please show for each of the loss factors in 2008 the underlying 12 constituent loss factors corresponding to the high, medium and low scenarios for the winter, spring, summer and fall seasons.	**The AESO has posted this information in Q4 2007 for 2008.**
6. The 2008 GSO shows the Sundance 4 Upgrade as a coal unit, yet it is located near the end of the stacking order at position 152. This unit was also included at the end of the stacking order in the 2007 GSO. In 2006 Milner sought clarification of the status of the Sundance Upgrade. The AESO responded, *"At the time of the publishing of the 2007 GSO, the Sundance 4 unit upgrade did not have a CCA but did have an ISD for 2007. Hence, it was regarded as preliminary and posted at the end of the GSO. The Sundance 4 project is an increase in capacity on an existing generator. As the capacity is new to the system, and connected to an existing generator, it represents a unique connection proposal. CEA statistics for performance were applied as per AESO Rules."* *b.) Sundance 4, at time of publishing, was designated preliminary generation"* a. Is the Sundance 4 Upgrade again designated as preliminary in 2008? b. If the Sundance 4 Upgrade is not preliminary, why is it not dispatched alongside other coal units in the GSO? What is the Sundance 4 Upgrade ISD?	**The in-service-date (ISD) for SD4 upgrade is September 09, 2007. The period used for historical data used in the 2008 GSO is June 01, 2006 to May 31, 2007. This is why the SD4 is still in the position in the 2008 GSO.**
7. In the Introduction section of the 2008 loss factors document of October 24, 2007 the AESO indicates, *"both the GSO and the Base Cases have been updated during the course of*	**Two Distribution Generators were added (Fort McLeod and Pocaterra). The line impedances of 7L62 and 7L72 are modified as per correct and updated information.**

the final calculations and reposted."	
8. On page 6 of the 2008 Loss Factors document posted on October 24, 2007, the AESO indicates, *"The load scaling used in the 2007 cases to meet the total GSO capacity is mainly responsible for the lower 2008 gross generation."* Please explain how the load scaling used in the 2007 cases is related to the 2008 gross generation.	**You have identified an error – the statement should read: "The load scaling used in the 2008 cases to meet the total GSO capacity is mainly responsible for the lower 2008 gross generation."**
9. On page 6 of the 2008 Loss Factors document posted on October 24, 2007, the AESO indicates the load treatment in the loss factor software is unchanged from what was done in 2007. However, on page 7 of this document the AESO indicates, *"Average System Losses and Shift Factor – In the 2008 GTA, the annual loss forecast is 2.91 TWH or 4.81% while average system loss forecast was 5.20% for 2007. The AESO expects the 2.91 TWH is in line with the actual losses.* ***The change in load treatment*** *(emphasis added) and the more accurate annual loss forecast result in a lower shift factor."* On page 8 of the 2008 Loss Factors document the AESO indicates, *"The 2008 loss factors are similar to the 2007 loss factors with some minor changes* ***reflecting the results of changed load treatment****, (emphasis added) load scaling, dispatched generation and transmission projects."* What change in load treatment occurred in the 2008 from what was done in 2007?	**The load treatment in 2008 LF calculation is same as the load treatment used in the 2007 LF calculation. But the load treatment is a modification over the original calculation used for 2006. The basis of the modification was described in the 2007 loss factor document.**
10. On page 7 of the 2008 Loss Factors document posted on October 24, 2007, the AESO indicates,	**The in-service-date of 500 kV KEG conversion was stated as October 31, 2007 as per project information made available in**

"In the 2007 cases, information up to late 2006 was used in the determination of loss factors. In the 2008 cases, additions during 2007 and expected additions in 2008 have been added. The major addition is the 500 kV KEG loop and the addition reduces system losses. Other system additions have been modeled in the 2008 cases; however they are not significant regarding losses." a. In what cases has the 500 kV KEG addition been included? b. When is the forecast In Service Date of the 500 kV KEG addition? c. What other system additions have been modeled in the 2008 cases? d. What is the change in system losses as a result of the 500 kV KEG loop? e. Appendix I of the 2008 Loss Factors document posted on October 24, 2007 shows that in 10 of the 12 scenarios, system load in 2008 is less than in 2007. At the same time the total system losses have increased in 10 of the 12 scenarios. As a result losses as a percentage of load have risen in almost every scenario in 2008. Why have total system losses risen while load has dropped? f. If the 500 kV KEG loop reduces system losses why have total system losses risen in 10 of the 12 scenarios given in Appendix I at the same time as load has decreased and why have losses recovered by raw loss factors remained unchanged?	**May, 2007, when the AESO was developing the models for the calculation. The project is included in all cases consistent with the LF rules.**
11. On page 8 of the 2008 Loss Factors document posted on October 24, 2007, the AESO indicates, *"The Northwest area has less credit than in the 2007 posted Loss*	**TMR calculation is based on historical data and the cases are prepared on forecast data. However, the loads in the cases are scaled down to match the GSO capacity.**

Factors. In general, higher generation (new generation accounts for 146 MW) and lower loads in the Rainbow and NW area drive loss factors towards more charges or less credit." In the AESO letter of September 28, 2007 Re: Draft Loss Factors for 2008 the AESO indicated, *"The Northwest area has less credit or more charges than in the 2007 Loss Factors. The Rainbow and North West area generation dispatched in the 2008 cases are higher than what was dispatched in the 2007 cases, mainly because of Transmission Must Run (TMR) and 146 MW of new generation additions."* If the loads in the Rainbow and NW are lower in 2008 and the modeled loads overall are lower than in 2007, why has the TMR dispatch in the NW gone up so much?	
12. The 2008 Generic Stacking Order Version 2, Released October 11, 2007 indicates that the AESO is forecasting 30 MW of TMR from Bear Creek G1 in the fall peak case. The 2007 fall peak case does not show a similar need. Why is additional TMR needed when both the 99 MW Northern Prairie Power project near Poplar Hill and the 47 MW project at Valleyview are forecast to be on line and generating at this time?	**The AESO does not comment on specific TMR contractual issues. The issue of TMR and energy market dispatch in the cases has been raised and addressed in previous year's loss factor consultations.**
13. The 2008 Generic Stacking Order Version 2, Released October 11, 2007 indicates that the AESO is forecasting a large increase in TMR from the Bear Creek G1 from the 2007 cases. The forecast need for TMR during the winter peak increases from 20 MW to 50 MW. During the winter medium case the need increases from 0 to 30 MW and in the spring peak case the need also increases from 0 to 30 MW. As mentioned above TMR is also expected to increase to 30 MW from 0 MW in the fall peak case. Given that the load in the 2008 cases is lower than that modeled in 2007, why is the forecast TMR dispatch at Bear Creek G1 rising so dramatically?	**The TMR calculation is based on historical data and the cases are prepared on forecast data. However, the loads in the cases are scaled down to match the GSO capacity.**

14. Table 1 of the 2008 Loss Factors posted on October 24, 2007 provides the loss factors for each generator for 2008. There does not seem to be a loss factor for either the Three Sisters hydro generator or the Interlakes hydro generator. Loss factors were given for these generators in 2006 and 2007 and in the draft loss factors posted on September 28, 2007. Why have the loss factors for these generators been dropped?	**Please see the response to # 7.**