2006 Generic Stacking Order

Draft for Comment

August 2005

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APEGGA Permit to Practice P-8200

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1.0 Purpose

The purpose of this document is to describe the 2006 Generic Stacking Order.

2.0 Introduction

The Generic Stacking Order (GSO) is a key component in the loss factor calculation, operational forecasts, planning studies, and General Tariff Application process. Generators are dispatched to meet system demand in the base cases according to the order and generation amount specified in the GSO.

The GSO contains two key pieces of information –

1. Generation supply levels on a net-to-grid basis (NTG) for 12 seasonal cases[1] (four seasons and three load levels) for all generators, and
2. Generation dispatch order.

Starting in 2006, the Rule governing the determination of the GSO generation supply levels can be located at: http://www.aeso.ca/files/May252005_FinalRules.pdf. In summary, the generation supply levels are determined using historical data for existing generators (in service for more than a year). For generators that have been in service for less than one year, the supply levels are estimated by the Incapability Factors. To determine dispatch order, a regression analysis is used to determine a relationship between the generator output and the actual historical hourly pool price. AESO will request annually from generation owners confirmation that the previous year's historical data is appropriate to use. Generation dispatch order is obtained based on regression analysis and the generation supply level within the GSO is determined using the Appendix – A of AESO Loss Factor Rules. Additional blocks are used where necessary

[1] Loss Factor base cases are relevant to NTG amount whereas operations and planning security base cases use more detailed modeling of the system including the behind the fence elements.

to reflect generators' multiple bidding strategies. The generation dispatch order is determined using the outcome of the regression analysis.

The TMR requirement (please refer to http://www.aeso.ca/files/ISO_OPP_2005_05_25.pdf for details) supersedes all other operational criteria and hence TMR generators are dispatched first on the list when required to fulfill the reliability criteria.

3.0 Background

In 2006, the AESO will use a new methodology for the determination of generator loss factors. The new methodology reflects the requirements of the Alberta Department Of Energy (DOE) 2004 Transmission Regulation. The regulation indicates that loss factors must be calculated from the average impact of generators on the Alberta Interconnected Electrical System (AIES). The regulation directed the AESO to implement a new methodology to meet these requirements. The AESO has consulted with stakeholders in the development of the new loss factor methodology including the development of new rules for the preparation of the GSO.

Previous GSO's used generators STS contract levels as capacity amounts. Moving to a historical generation basis has several advantages, including;

- Representative of actual generator energy market dispatch for the previous period
- Addresses the issue of confidentiality of maintenance data by including actual maintenance and forced outages from the previous period
- Reduces necessity for the AESO to forecast generator / pool price relationships

4.0 2006 GSO Key Changes

The major differences between previous GSOs and the 2006 GSO are;

1. Average historical net-to-grid (NTG) output of a generator is considered for each seasonal case.
2. Generator owners are provided an opportunity to comment and suggest revisions to the GSO capacities to reflect an intent change operation in a future year.
3. The hours used for averaging the historical generator output are taken from the AIES seasonal load duration curve analysis (Please see Appendix-A of AESO Loss Factor Rules).
4. No maintenance or outage data is used in the 2006 GSO as average historical net-to-grid output of a generator inherently contains this information.
5. 12 seasonal net-to-grid generations are assigned to each individual generator at the point of supply (POS).
6. The order except for price takers (such as wind) and hydro generation, is determined by the actual price responses of the generators in each group.
7. New generators that are expected to be connected in the forecast year will be included in the GSO. These are generators with signed contracts to connect or who have made significant financial commitments to connect. Generators who have filed decommissioning plans with the AESO will be removed accordingly.

   AESO relies on the Canadian Electricity Association (CEA) information in the event of new generators or in the case of a lack of updated information from the generators on their availability. The incapability Factors (ICBF) is used to calculate the power available to the AIES. (1- ICBF) has been considered as equivalent to Available Capacity Factors (ACF). The ICBFs are obtained from CEA's latest annual report on Generation Equipment Status.
8. The 2006 GSO considers the NTG amount at the point of supply (POS). Since any given loss factor is primarily the function of net to grid amount

of generation, the 2006 GSO represents an aggregate of generation at the point of supply. An equivalent generator is considered at the bus from which the NTG amount related to the Measurement Point Identification (MPID) is obtained. For example, Horseshoe has 4 generators with a single MPID which is HSH. The 4 generators are connected to Bus 172 (12 kV). They are represented as a single unit at Bus 171 (138 kV) because the AESO billing database contains NTG data for all of these four units (related to MPID HSH) at Bus 171. The same approach is applied to the Industrial System Designations (ISD). All ISDs are represented by a single equivalent generator and load. The GSO contains a column with bus numbers for corresponding MPIDs.

The 2006 GSO is similar to its predecessors in the following aspects:

1. The price takers are ranked according to their relative loss factors.
2. No bid price, specific TMR, or heat rate information is revealed.
3. Multiple blocks (two blocks) are used to represent the historical response of the generators to pool price.
4. STS contract and incapability factors (ICBF) is used to determine the amount of predicted generation level for new generators.

5.0 2006 Generic Stacking Order

The following describes the application of the GSO to the loss factor base cases:

1) Transmission Must Run (TMR) generators – the generators represent the expected TMR dispatch of gas and combined cycle units beyond area generation energy market participation. The TMR units are listed in the AESO OPP’s 501 and 510. TMR is required in specific areas of the AIES to meet reliability criteria The total net-to-grid (NTG) amount assigned to the TMR generators in the 2006 GSO is obtained from the following two sources:

a) The average historical net-to-grid (NTG) is calculated for 12 seasonal cases in the past twelve months (June 1 2004 to May 31 2005). The AIES seasonal load duration curve analysis is used to obtain the NTG amount of each generator.

b) The minimum TMR requirement is obtained using OPPs 501 and 510.

   According to the OPPs when the area criteria requirement is not met by the generation from local generators through energy market dispatches, TMR dispatches will be issued to TMR-contracted generators to make up the shortfall. TMR-contracted generators will be dispatched according to the TMR dispatch orders. The actual TMR dispatch order is confidential to the AESO.

   Area load is required to determine the minimum TMR requirement for any TMR area such as North-West area. The minimum TMR requirement is function of local area load. The area load is obtained for high, medium and low seasonal cases using the historical hourly area load levels and using the regression analysis as explained in Appendix-A of the AESO Rule on Loss Factors. The next step is to assign minimum TMR generation requirements to generators listed in the OPPs according to these seasonal load levels.

2) Most of the data used in 2006 GSO such as Alberta system load, hourly pool price and generation amount at each POS are historical and taken from the most recent 12 months' data found in the AESO's billing system. The data extraction period is June 1 2004 to May 31 2005.

3) In general, the dispatch order is formed to more closely reflect an actual operational perspective. The generators may bid multiple blocks but the typical block size beyond the 2nd block is very small. In order to avoid additional complexity for limited modeling improvement, at most two blocks are considered in the GSO. However, not all generators have a 2nd block. The regression analysis shows that some generators have

an insignificant amount of generation in the 2nd block which indicates their price insensitivity.

4) **Wind Generation** – Wind generation does not have a relationship to pool price.

5) **Small Power Research & Development** – The relative order remains the same as the 2005 GSO. SPR&D generators are price takers and are exempt by law from paying for losses.

6) **Distribution Connected Generation** – consists of distribution connected generators who occasionally supplies power to the AIES.

7) **Preliminary Generation** – consists of the generators with preliminary status. These generators do not have a contract with the AESO but are included in the 2006 GSO as it is expected they will connect.