Transmission Loss Factor Methodology And Assumptions Appendix 8

Operations & Reliability

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Table of Contents

1. Introduction

This document is a supplement to the ISO Rule and provides details on the processes and assumptions used to calculate transmission Loss Factors.

2. Methodology

The new loss factor methodology is described in the following three sections; Load Flow Loss Factors, Energy Loss Factors, and Compressed Loss Factors.

2.1 Load Flow Loss Factors (‘Adjusted’ Raw Loss Factors)

Raw loss factors are calculated for each generator for each base case load flow condition. Each base-case load flow is selected to represent a typical operating condition on the system, based on historical system loading condition.

Twelve (12) base cases are used to give snapshots of system loading conditions and losses over each of the four - “three-month seasons” of the year (winter, spring, summer and fall). For each season, snapshots are taken at representative peak, median and low load conditions.

Adjustments are made to the historical power generation output if necessary to reduce imports and exports set to zero. Floating the inter-ties will be carried out using a generic stacking order for generation. Generators not represented in the ‘historical’ load flow model but which would be in merit according to the stacking order will be assumed to be on maintenance or forced outage. Generators modeled in the load flow but not in merit according to the historical load flow will be assumed to be generating according to market conditions, and will continue to be operated at their base case values. Other generation will be added or removed to reduce exports to zero according to stacking order but recognizing any constraints imposed by the transmission system.

The methodology to determine a load flow based ‘raw’ loss factor for one of the generators has been called the “50% Area Load Adjustment Methodology” to differentiate it from other methodologies evaluated. In the methodology, it is assumed that the generator for which the loss factor is to be evaluated is going to supply the next increment in load on the AIES. If the loss factor were calculated using a load flow program the procedure would be to set the generator for which the loss factor is to be calculated as the swing bus for the system. Every load within the AIES would be increased by a common factor and a loss gradient would be determined for the generator equal to the total change in system losses divided by the change in output of the generator for which the loss factor is being calculated. The ‘raw’ loss factor for the generator for the load flow is set equal to ½ of the gradient.

This process would be repeated for each generator.

In the proposed methodology, the calculation of ‘raw’ loss factors will be done analytically with a custom program that uses the load flow solution as a base and computes the 'raw' loss factors analytically for each generator in a single numerical process.

Several assumptions inherent in the analytical method are:

a) All bus voltages (and bus voltage angles) remain unchanged. This is a reasonable assumption if the magnitude of the power change is very small.

b) The var component of the load is unchanged as a result of the change in MW load. As the proposed methodology is attempting to establish the impact of generator MW output on MW load, this is a reasonable assumption to decouple secondary var effects.

c) The var output of the generators is constant. This is consistent with the load var change assumption for small changes in generator output.

d) The load change is applicable to only loads in the AIES. For Industrial System Designations (ISD) where the ISD is receiving power, the increment in load is based on the net load at the metering point. For ISD's where the ISD is supplying power, the ISD is treated as an equivalent generator with output equal to net to grid at point of metering.

'Raw' loss factors calculated in this manner for every generator (or equivalent generator) when multiplied by the generator output in MW and summed for all generators in Alberta will account for almost 100% of the load flow losses for the Alberta system. The shift factor required to compensate for over or unassigned losses is extremely small. The Small Power Research and Development generators do not receive loss factor charges or credits and their contribution to losses is compensated for by an additional small load flow shift factor component implying that all generators are compensating for the unassigned component with distribution based on their power output in the load flow. The net shift factor due to both components is typically less than 0.1%. The raw loss factor from the load flow for each generator adjusted by the shift factor is called an 'adjusted' raw loss factor.

2.2 Energy Loss Factors

The proposed process to calculate energy –"based normalized" loss factors for each of the generators is as follows:

A seasonal 'adjusted' raw loss factor is calculated for each generator equal to the weighted average of the three 'adjusted' raw loss factors determined for each of the three system loading conditions for the season. The seasonal 'adjusted' raw loss factor is multiplied by the forecast generator volumes for each generator to establish a preliminary allocation of losses for each season. The total allocation is compared to the estimated energy losses for the system and a seasonal shift factor is introduced to account for any differences between allocated and estimated energy losses. The normalized Annual Loss Factor (Final Loss Factor) is set as the weighted average of the four seasonal shifted loss factors.

2.3 Compressed Loss Factors

If a situation does arise where compression is necessary, the following methodology will be adopted:

- The loss factors of all generators outside of the valid range will be limited to the valid range, and
- A shift factor will be applied to the loss factors for all generators not on the limit with the first calculation.

If any loss factors lie outside the range as a result of application of the shift factor, the loss factors of all of the generators that were not originally on limits would be 'linearly compressed'. The difference between the shifted loss factor and the system average loss factor would be multiplied by a constant factor and the result added to the average loss factor to ensure that all loss factors are within limit. The final loss factor will be referred to as a 'compressed' loss factor.

3. Loss Factor Procedures

3.1 Development of Base Cases

A single suite of up-to-date base cases for calculating the annual loss factors will apply from January through December. The base cases comprising load profiles using the ISO load forecast shall include:

- Peak, median, and light load cases for the three month period December , January, and February (winter season),
- Peak, median, and light load cases for March, April, and May (spring Season),
- Peak, median and light load cases for June, July, and August (summer season), and
- Peak, median, light load cases for September, October, and November (fall season).

The swing bus to be used will be 1520 (WECC equivalent bus). The ISO load forecast to be used will be the latest approved forecast created during the current year by the ISO. The same forecast will be used to provide a set of forecast loss factors for a period five years out. For the annual loss factors, a forecast set of loss factors will also be provided for the fifth year out. Base cases will be developed by the ISO. The base cases will include:

- All facilities that are commissioned as of December 1 of the current year and that have no approved plan for decommissioning prior to January 1, of the sixth year out.

- All facilities that have a planning flag set to be included in all base cases for a season, provided that the planned In-Service Date for the facility is on or before the midpoint of the season. Otherwise they will be included in the following season.
- All customer initiated projects (including load, generation and associated transmission facilities) that have a Customer Commitment Agreement (CCA) to be included in all base cases for a season, provided that the planned In-Service-Date for the facility is on or before the midpoint of the season. Otherwise they will be included in the following season.
- All ISO initiated projects for which the Board has approved the "Need" to be included in all base cases for a season, provided that the planned In-Service Date for the facility is on or before the mid-point of the season. Otherwise they will be included in the following season.
- Planning generators as required for fifth year forecast.
- The three base cases for each season will have identical physical topology and show all projects whose In-Service-Date falls before the midpoint of the season.

Status of facilities (in-service or out-of-service) to be adjusted as follows:

- Normally in-service status shown on the operating single line diagram.
- Seasonally switched device status will show their normally in-service status, and be adjusted by ISO who will adjust status only as explicitly specified from the TFO.

3.2 Development of Generic Stacking Order

A Generic Stacking Order (GSO) will be developed or modified each year by the ISO. The Generic Stacking Order shall be based on at least the following considerations:

- GSO constructed according to historical Point Of Supply (POS) metering records.
- GSO for system peak will be based on maximum (100th percentile of all metering records) output of the POS for the relevant season.
- GSO for system median (50th percentile of all metering records) output of the POS for the relevant season (considering only those POS records above some minimum threshold to be established).
- GSO for system minimum (zero percentile generation) output of the POS for the relevant season (considering only those POS records above some minimum threshold to be established).
- Any new generators for which a historical record is not available will be dispatched according to the ISO's analysis of the generator technology. Its power output would be based on its Incapability Factor. Industrial system generation and hydro generation to be re-dispatched accordingly.

ISO will develop additional base cases for the calculation of Opportunity Service including interruptible Imports, Exports, and Demand Opportunity Service.

3.3 Calculation of Loss Factors

The ISO will calculate the loss factors for each year using the base cases developed for Firm Service and the additional base cases developed by the ISO for Opportunity Services. For Firm Service, the ISO will adjust the resulting generation dispatch according to the GSO to achieve a zero MW exchange at all inter-ties.

3.3.1 Loss Factors for Firm Service (STS)

In the proposed process the ISO would use historical production data to determine the power level to be used for existing generators, and STS contract levels for new generating units in developing the twelve base cases for loss factors. Each base case contains its own dispatch order based on a common annual stacking order. The stacking order stays the same in each base case with respect to the order of dispatch, but the amount of power dispatched by each unit varies because of seasonal considerations. The ISO, through discussions with new generators, would add the new generator to the existing stacking order. Its power output would be based on its Incapability Factor. The Incapability Factor (ICBF) = 1 – Available Capacity Factor (ACF). If the new unit is an addition to an existing plant using the same connection configuration, then it will receive the same loss factor as the existing units. The base cases used to calculate the loss factors for the generators would all contain a zero value for the exchange across the inter-ties. Loss Factors calculated with inter-ties set to zero power flows reflect the losses associated with the supply of energy for domestic load. Commencing January, 2006 Loss Factors will be limited to a maximum charge of two times system average losses and credits will be limited to one times system average losses. This restriction is a directive of the Transmission Regulation (Section 19(2) (f)).

3.3.2 Loss Factors for Firm Import Service (not currently available)

Determination of a loss factor for Firm Import Service will be calculated with the contracted value of the transaction (in MWs) represented as a generator located at the appropriate inter-tie border. The base cases used for the determination of STS loss factors will be modified to include the firm import transaction. This contract loss factor is will apply to all transactions not exceeding the contract limits for the party requesting firm import service.

3.3.3 Loss Factors for Opportunity Import/Export Service

Export transactions will be represented as a negative generator and import transactions will be represented as generators on the appropriate inter-tie at the Alberta border. The base cases used to determine the system loss factors would be adjusted to include the proposed transaction(s) and the loss factors for the export or import will be calculated. The import and export levels for loss calculations will be based on the historical transfer levels for the previous three month season. The loss factors will be calculated using the 80^{th} percentile of the metered transfer levels. Loss factors will be calculated for on-peak and off-peak load conditions.

Loss factors for opportunity export transactions are not subject to compression (i.e. their loss factors can exceed the loss factor envelope of three times system average losses). Opportunity import loss factors will be treated the same as firm service and will be compressed to comply with the loss factor envelope of three times system average losses. Import transactions must not result in perverse pricing signals; i.e. an import can not receive a larger credit than a generator in Alberta located at the border.

3.3.4 Loss Factors for Demand Opportunity Service (DOS)

Loss Factors for DOS are calculated on a seasonal basis. Seasonal system losses would be calculated based on the three base cases for each season with the inter-ties set to zero exchange. The DOS transaction would be represented as a negative generator and the losses will be calculated for each season. DOS loss factors are location based and are not subject to compression, i.e. DOS loss factors can exceed the loss factor envelope of three times system average losses.

3.3.5 Loss Factors for Merchant Transmission Lines

The loss factors for Merchant Lines connected to the Alberta grid will be calculated using the same base cases as the calculation of loss factors for generators. The twelve base cases used would contain zero exchange across each inter-tie. Exports would be modeled as a negative generator and imports would be modeled as a generator. The loss factors would be location based. If the merchant line has a mid-terminus within Alberta, it would be treated the same as the end of the line (terminus), i.e. imports as generators and exports as negative generators. A merchant line will be treated the same as existing inter-ties.