Milner Power Inc.

Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

ATCO Power Ltd.

Complaint regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

Phase 2 Module B

November 26, 2015
Alberta Utilities Commission
Decision 790-D03-2015
Milner Power Inc.
Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology
ATCO Power Ltd.
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Applications 1606494, 1608563 and 1608709
Proceeding 790
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1. INTRODUCTION

1. This decision is one in a series of related decisions made by the Alberta Utilities Commission (AUC or the Commission) regarding a complaint made by Milner Power Inc. (Milner) on August 17, 2005, about the Independent System Operator (ISO) rule 9.2: Transmission Loss Factors and Appendix 7: Transmission Loss Factor Methodology and Assumptions (collectively the Line Loss Rule) that was implemented by the Alberta Electric System Operator (AESO) on January 1, 2006. References to the Line Loss Rule should be read as the 2005 Line Loss Rule as adjusted from time to time during the period from January 1, 2006 to the present.

2. On August 8, 2014, the Commission, after canvassing the parties, determined that it would proceed to hear Phase 2 of this proceeding in three modules. Module B was described as follows by the Commission:

   9. Module B will address the development of a new loss factor methodology and line loss rule that meets the legislative requirements. On May 23, 2014, the AESO submitted that it anticipated it could design a methodology consistent with the findings in the Commission’s decisions and the legislation. In a subsequent submission on June 6, 2014, the AESO stated that it expects to be able to file its proposed new methodology within 4 months. The Commission directs the AESO to file the proposed new rule and methodology in this proceeding by no later than December 4, 2014. Also, the Commission will consider submissions from all parties as to what order(s) the Commission should issue to the AESO, pursuant to the Electric Utilities Act, in relation to the proposed new rule.

3. Throughout this decision, distinctions are made between the provisions of the 2003 Electric Utilities Act and the 2007 amendments to the 2003 Electric Utilities Act. The 2003 Act will be referred to as the 2003 Electric Utilities Act and the Act incorporating the 2007 amendments will be referred to as the 2003/07 Electric Utilities Act. Where the Commission makes reference to the Electric Utilities Act without specifying whether it is the 2003 or 2003/07 Electric Utilities Act, it does so because there is no material difference between the two Acts relevant to the discussion. When the Commission discusses provisions of the 2003 Electric Utilities Act it refers to the powers of the Board under that Act and when it discusses provisions of the 2003/07 Electric Utilities Act it refers to powers of the Commission. Both versions of the Electric Utilities Act are discussed in the present tense. Throughout this decision, references to

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1 Exhibit 524.01, AUC letter re issues list and schedule for Phase 2, August 8, 2014.
Section 19 of the *Transmission Regulation* AR 174/2004 should also be read as references to Section 31 of the 2007 *Transmission Regulation* as amended.

4. The chronology of determinations made by the Commission and its predecessor, the Alberta Energy and Utilities Board, with respect to Milner’s complaint, the Line Loss Rule and related matters is found in Section 2 of AUC Decision 790-D02-2015; *Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology*.

1.1 **Summary of decision**

5. In this decision the Commission has determined the following:

a) In Section 2: The AESO’s filing of a proposed rule that would, in its opinion, comply with the Commission’s determinations in Decision 2014-110: *Applications for review of AUC Decision 2012-104: Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology*, is not a compliance filing. The Commission did not issue directions to the AESO specifying what a compliant line loss rule should include. It is only in Module B that, the Commission is exercising its jurisdiction pursuant to Section 25(6) of the *Electric Utilities Act* to specify what changes are to be made to the current non-compliant Line Loss Rule in order that it be compliant with the *Electric Utilities Act* and the *Transmission Regulation*.

b) In Section 3: The Commission directs the AESO to make changes to the current non-compliant Line Loss Rule replacing the current Corrected R-Matrix 50 per cent Area Load Adjustment Methodology (MLF/2) with an incremental loss factor (ILF) methodology for calculating raw loss factors using the Load Flow approach. The Commission does not accept the ENMAX superposition proposal because it does not comply with the Act and Regulation.

c) In Section 4: The Commission directs the AESO to make changes to the current non-compliant Line Loss Rule to specify that the location of a “generating facility,”\(^2\) will be the location of each metering point identifier (MPID) for a generating unit or group of generating units.\(^3\) This approach obviates the need for an exception list (as proposed by the AESO).\(^4\) This decision also provides for generators that own or control generating facilities to aggregate or disaggregate their generating facilities as they choose, at the same location as explained in greater detail below.

d) In Section 5: The Commission directs the AESO to perform the ILF calculations by keeping load constant when a generation facility is (notionally) removed from the system and scaling up (i.e., notionally re-dispatching) other specific generation facilities to rebalance the system. The Commission does not adopt the AESO’s generic stacking order (GSO) for this purpose. Rather, the Commission directs the AESO to use energy market merit orders from the previous year (with necessary

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\(^2\) The term generating facility is not defined in the legislation or ISO rules. It is a term used here by the Commission to reflect a generic source of electric energy – it is not to be confused with a generator, a generating unit, an aggregated generating unit, or a group of generating units.

\(^3\) Each generating facility associated with a unique metering point identification is allocated seven non-transferable operating blocks (hereinafter referred to as “price quantity pairs”), pursuant to a supply transmission service (STS) contract between the ISO and the owner of the generating facility in question.

\(^4\) Exhibit 790-X0289, AESO Amended List of Measurement Point Exceptions, May 19, 2015.
adjustments for forecasted changes in the generation mix) in order to forecast the line loss factors for the upcoming year. Instead of using twelve base cases (as currently employed by the AESO), the Commission directs that the actual merit order in each of the 8,760 hours of the previous year be used for this purpose. However, if the AESO considers that a smaller number of hourly observations would not materially reduce the accuracy of line loss factors calculated by notionally re-dispatching output to rebalance the system, the AESO may propose such a smaller number of hours along with supporting statistical or other analysis.

e) In Section 6: A number of detailed implementation issues are addressed.

f) In Section 7: The Commission issues its order in this decision and addresses the effective date for implementation of a revised compliant rule.

6. In reaching these and other related determinations in this decision as discussed in more detail below, the Commission has carefully considered all applicable legislation and regulations, the complete evidentiary record of this proceeding, the physical structure and operation of the Alberta interconnected electric system (AIES), the public interest to be served by a legislatively compliant line loss rule, the history of the existing unlawful Line Loss Rule and whether it may have affected generator decisions on where to physically locate (i.e., build) new generation (including new generating units) after the current Line Loss Rule had come into effect, the uncertainty as to the ultimate lawfulness of the current Line Loss Rule arising from the time Milner first filed its complaint, the nature and manner of operation of the AESO’s proposed new line loss rule, its compliance with the legislative and regulatory framework and the feasibility of implementing it.

2 SCOPE OF PHASE 2 MODULE B OF THIS PROCEEDING

7. Milner’s original 2005 complaint sought relief under Section 25(6) of the 2003 Electric Utilities Act. That section provides that the Board may order the ISO to revoke or change a provision of an ISO rule that, in the Board’s opinion, is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the 2003 Electric Utilities Act or the regulations.

8. In 2010, the Alberta Court of Appeal remitted Milner’s 2005 complaint “…to further investigate or hold a hearing to determine whether there was a contravention of Section 19 of the Transmission Regulation as alleged.” To this end, the Commission issued a September 20, 2010 Notice of proceeding which it designated as Proceeding 790. In a letter dated February 28, 2011, the Commission bifurcated Proceeding 790 into two phases: the first phase to consider whether the 2005 Line Loss Rule contravened Section 19 of the 2004 Transmission Regulation and the second phase to determine the relief that might be granted should the complaint be upheld.

9. Effective October 10, 2012, the AESO filed ISO rules Section 501.10 with the Commission and removed ISO rule 9.2, the 2005 Line Loss Rule, as part of the AESO’s Transition of Authoritative Documents Project. This was filed by the AESO on an expedited
basis under Section 20.6 of the 2003/07 Electric Utilities Act as amended to that date in Application 1608876. The AESO’s October 2, 2012, Notice of Filing respecting this rule stated that the changes were not intended to circumvent or dismiss the complaints submitted by Milner and ATCO Power Ltd. (ATCO) against ISO rule 9.2. The AESO further stated that it wished to preserve the complaints by Milner and ATCO and requested the Commission to transfer the complaints to ISO rules Section 501.10 upon removal of existing ISO rule 9.2.⁹

10. On April 16, 2014, in Decision 2014-110, the review panel upheld the findings of the Commission in Decision 2012-104 that the 2005 Line Loss Rule was unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory and inconsistent with and in contravention of the 2003 Electric Utilities Act and the relevant portions of the 2004 Transmission Regulation dealing with line losses.

11. In particular, Decision 2014-110 stated:

The review panel has considered carefully the evidence regarding how the 2005 Line Loss Rule operates and finds that it does not comply with Section 19(1)(a) and Section 19(2)(d) of the 2004 Transmission Regulation and Section 25(6)(b) of the 2003 Electric Utilities Act.¹⁰

…

To summarize, for the reasons given in this decision, the review panel concurs with the hearing panel’s finding that the AESO’s MLF/2 [marginal loss factor divide by two] line loss methodology does not comply with sections 19(1)(a) and 19(2)(d) of the 2004 Transmission Regulation because the AESO’s 2005 Line Loss Rule fails to assign to each generating unit a line loss charge or credit (i) based on each generating unit’s contribution to transmission line losses and (ii) that is representative of each generating unit’s impact on average system losses relative to load. As the majority stated in Decision 2012-104, the MLF/2 methodology is unjust because it disadvantages loss savers and does not properly charge loss creators for their losses. It is also “unjustly discriminatory” as it violates all the principles of rate design that would normally be observed in a regular rate or tariff proceeding.¹¹

12. On August 8, 2014, the Commission released an issues list and proceeding schedule directing that Phase 2 of Proceeding 790 be divided into three modules, Modules A and B which would run concurrently and Module C which would proceed only if required, based on the outcome of the first two modules.¹² Module B was directed to address the development of a new line loss factor calculation methodology and line loss rule that meets legislative requirements.

13. In Decision 790-D02-2015 the Commission determined issues addressed in Module A of Phase 2 of Proceeding 790. The Commission made the following findings (the reasons for which are explained in greater detail in Part 4.1 of that decision). First, for the purposes of Milner’s complaint, the Line Loss Rule has not been replaced by a new rule. Rather, it continued in all

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⁹ Exhibit 533.02, AESO Line Loss Consultation, September 5, 2014, pdf page 959.
¹¹ Ibid., page 38-39, paragraph 121.
¹² Exhibit 524.01, AUC Letter re issues list and schedule for Phase 2, August 8, 2014.
relevant respects since it was put into effect January 1, 2006 because it still employs the MLF/2 methodology which does not comply with applicable provisions of the Transmission Regulation. Second, while the test for relief in the 2003/07 Electric Utilities Act is stated differently, this legislative change did not change materially the relief that might be granted under either the 2003 Electric Utilities Act or the 2003/07 Electric Utilities Act.

14. On May 23, 2014, the AESO filed a letter with the Commission stating that it anticipated it could design a methodology consistent with the findings in the Commission’s decisions and the legislation.13

15. In a subsequent submission on June 6, 2014, the AESO stated that it expected to be able to file its proposed new methodology within four months.14 In a letter dated August 8, 2014, the Commission directed the AESO to file its proposed new rule and methodology in this proceeding by no later than December 4, 2014. This filing date was prior to the date of the hearing process set for consideration of the issues to be determined in Module B. This filing would allow consideration of the AESO’s proposed new rule in the Module B hearing. The Commission did not otherwise change its previous process directions for the conduct of Phase 2.

16. In this proceeding, Milner’s position is that the AESO’s submission of a proposed new line loss rule constitutes a compliance filing and, as such, “there is only one methodology properly before the Commission” in Module B - the AESO’s proposed ILF by unit methodology and line loss rule.15

17. Section 25(6)(b) of the 2003 Electric Utilities Act authorizes the Commission to order the ISO to change a provision of an ISO rule that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the 2003 Electric Utilities Act or the regulations.

18. Section 25(6) of the 2003/07 Electric Utilities Act, meanwhile, authorizes the Commission to direct changes to an ISO rule as follows:

(6) The Commission may, after hearing a complaint, by order,

…

(e) direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

(7) The Independent System Operator must file with the Commission an ISO rule that is changed pursuant to an order under subsection (6)(e).

19. The Commission did not direct or order the AESO to take the step of filing a proposed rule that it considered would be consistent with Decision 2014-110. Instead, the Commission directed the AESO to file, by a specific date, the rule the AESO had volunteered to file.

20. The Commission’s August 8, 2014 letter also invited submissions from all parties as to what order(s) the Commission should issue to the AESO pursuant to the Electric Utilities Act in

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14 Exhibit 518.01, AESO Phase 2 process reply submission, June 6, 2014, page 1.
relation to the proposed new line loss rule. On December 4, 2014, the AESO filed the ILF by unit methodology which it had developed. The AESO subsequently advocated this methodology at the hearing and continued to modify it during the hearing process. Other parties also filed loss factor proposals with the Commission as they were entitled to do pursuant to the Commission’s August 8, 2014 letter. Some parties (TransCanada Energy Ltd. (TransCanada), Capital Power Corporation (Capital Power), ATCO, Powerex Corp. (Powerex), Milner and the City of Medicine Hat (Medicine Hat)) agreed with the AESO’s use of the ILF methodology but suggested different ways in which ILF should be implemented. ENMAX Energy Corporation (ENMAX) filed a different proposal (superposition) which did not employ an ILF approach. At the time of the August 8, 2014 letter, the Commission had not yet determined what directions it would issue to change the current non-compliant Line Loss Rule. That is the purpose of this Module B decision.

21. The proposed new line loss rule filed by the AESO with the Commission on December 4, 2014 is not a filing as contemplated in Section 25(7) of the 2003/07 Electric Utilities Act. The Commission did not give directions to the AESO specifying what a compliant line loss rule should include. In Module B, the Commission is exercising its jurisdiction pursuant to Section 25(6) of the Electric Utilities Act to specify what changes are to be made to the current non-compliant Line Loss Rule in order that it be compliant with the Electric Utilities Act and the Transmission Regulation. As such, the AESO’s proposed line loss rule is not the only proposal properly before the Commission in Module B of this proceeding. Instead, all proposals made by various parties with respect to a revised line loss rule are equally entitled to full consideration by the Commission and, in fact, have been given such consideration by the Commission.

3 RAW LOSS FACTOR METHODOLOGY

3.1 Raw Loss Factor Approaches

22. In Decision 2014-110, the Commission found that the MLF/2 methodology employed by the AESO to calculate raw loss factors did not comply with the Transmission Regulation or the Electric Utilities Act. Therefore, a different method which does comply is required. As noted above, there are two different methodologies for the calculation of raw loss factors proposed in this proceeding, the ILF methodology (filed by the AESO and supported by a number of parties) and the superposition methodology (filed by ENMAX and supported in final argument by TransAlta). In this section of the decision, the Commission considers whether ILF or superposition, or both, are compliant methods for calculating raw loss factors.

3.1.1 Incremental Loss Factor (ILF) Approach

23. As described by the AESO “the ILF by unit methodology measures the difference between system losses with and without each generating unit…” The AESO also stated:

An ILF methodology calculates an incremental loss factor by comparing changes in the system losses when the average level of net-to-grid generation of a specific generator is reduced to zero from the base case. This assessment with and without a generator’s full output was referred to in past proceedings as the “but for” approach.

The AESO in several instances refers to its methodology as ILF by unit. See for example 790-X0344, AESO reply evidence, paragraphs 8 and 16; and exhibit 790-X0409, AESO argument, page 2, paragraph 6.

Exhibit 790-X0409, AESO argument, July 31, 2015, page 6, paragraph 23.
24. Capital Power described the ‘but-for’ approach in argument as follows. “Once base cases have been generated at Step 1, and assuming total losses have been accurately computed, the AESO then assesses impact on average system losses through the removal of each generator observing total system losses before and after its removal...”\(^\text{18}\) [emphasis added]

25. ATCO testified as follows:\(^\text{19}\)

“Impact” is inherently a measure of change and any analysis of an impact must involve two scenarios.

To determine the impact of a generator on system losses, one needs two operating states: an “actual state” (with the generator) and a “hypothetical state” (without the generator)...

26. ENMAX (which is opposed to ILF) described ILF as a methodology that determines each generator’s impact on system losses by comparing total system losses in the with- and without-generator cases. It then calculates each unit’s impact by subtracting one number from the other to find the resulting increase or decrease in system losses.\(^\text{20}\)

27. No party objected to these descriptions or to the characterization of ILF as being a ‘but-for’ approach.

28. Section 8 of the AESO’s proposed line loss rule describes the ILF ‘but-for’ approach as follows:\(^\text{21}\)

Raw Loss Factors
8(1) The ISO must calculate raw loss factors for each base case created in subsection 6 above using an incremental loss factor methodology.

... 

(3) The ISO must calculate a raw loss factor for each system access service provided under Rate STS, Rate DOS, or Rate IOS in each base case created in subsection 6 above by:

(a) calculating transmission system losses in the base case with the system access service connected to the transmission system;

(b) calculating transmission system losses in the base case with the system access service disconnected from the transmission system... ; and

(c) dividing:

(i) the difference between the transmission system losses calculated in subsections 8(3)(a) and 8(3)(b) above, by:

(ii) the dispatch volume, in MW, associated with the system access service when connected to the transmission system in subsection 8(3)(a) above.

\(^{18}\) Exhibit 790-X0412, Capital Power argument, July 31, 2015, page 6, paragraph 16(ii).

\(^{19}\) Exhibit 790-X0156, ATCO responses to ENMAX information requests, April 2, 2015, PDF page 10, paragraph (i)(iii).

\(^{20}\) Exhibit 790-X0411, ENMAX argument, July 31, 2015, page 10, paragraph 52.

29. Section 19(1)(a) of the *Transmission Regulation* requires that a compliant line loss rule calculate the contribution of each generating unit to total line losses. Section 19(2)(d) states that line loss factors must be representative of the impact on average system losses... relative to load. The AESO and the parties that support adoption of an ILF methodology emphasize that an ILF methodology measures the difference between two scenarios for each generating facility – one with the generating facility connected to the system and one where the facility is disconnected from the system. They emphasize that such an approach gives effect to the requirement that the line loss factor measure the *impact* of a generating facility on average system losses.

30. As discussed in the review hearing leading to Decision 2014-110, conceptually, there are two different categories of line losses attributable to the operation of each generator. The first category has frequently been termed a generating unit’s “own losses” referring to losses in the form of heat resulting directly from each generator’s own transmission of electricity. These losses are always positive. The second category of losses consists of aggregate system losses (either positive or negative) caused by each generator’s power flows displacing and changing the power flows and consequential line losses of other generators operating on the transmission system. For any line loss saver, the aggregate system-wide savings brought about by its operation, must, by definition, be greater than its own line losses. The Milner and ATCO evidence indicates that, unlike the MLF/2 methodology, the ILF methodology calculates the actual change in system losses consequent upon operation of each generator. The AESO, in final argument, stated that unlike a marginal approach, the ILF methodology recognizes the effects of a generating unit’s full range of output (as expressed by the Commission in Decision 2014-110 at paragraph 115).  

31. According to Milner, ATCO and the AESO, the ‘but-for’ approach embodied in the AESO’s ILF methodology calculates a final loss factor representing the net contribution to total system losses attributable to the operation of each generating unit (i.e., the combined impact of each generating unit’s own losses plus indirect losses) based on its location. These parties contend that in so doing, the ILF methodology meets the requirements of sections 19(1)(a) and 19(2)(d) of the *Transmission Regulation* and overcomes the concerns raised by the Commission in Decision 2014-110 with respect to the current Line Loss Rule.

32. The AESO summarized why it believes its proposed new line loss rule complies with applicable legislation and regulations as follows:

> 14. The AESO submits that the Commission should confirm the AESO’s proposed ILF by unit methodology because it addresses the concerns of the Commission identified in Decision 2014-110 regarding the current MLF/2 methodology and the relevant legislation. Specifically, the proposed ILF by unit methodology:

> (i) is incremental as opposed to marginal, so it recognizes the effects of the full range of a generating unit’s output by comparing changes in the system losses when the average level of net-to-grid generation of a specific generator or group of generators is reduced to zero from the base case;

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23 Medicine Hat also stated that it supports an ILF methodology in exhibit 790-X0403, Medicine Hat argument, July 31, 2015, page 79, paragraph 298.
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(ii) measures losses on a by unit basis, so it:

(A) allocates line losses to the generating unit causing the losses and credits; and

(B) assigns to each generating unit a loss factor that is based on that generating unit’s contribution to losses, in accordance with the principles of cost causation; and

(iii) measures losses relative to load, so it reduces load to balance remaining supply when a generator or group of generators is reduced to zero.

33. Many of the parties to this proceeding, including several of those supporting and all of those opposing an ILF approach to the calculation of line loss factors, raised various objections, concerns and reservations with respect to the AESO’s proposed line loss rule. However, most of these objections were directed at implementation-related issues. The two most important of these relate to the location at which the ILF calculations are to be undertaken and technical issues associated with the AESO’s choice of swingbus to rebalance the system once a generating facility is withdrawn. Very few objections were directed at the basic concept underlying the incremental loss factor methodology, namely, that one way to estimate a generating facility’s contribution to total line losses and its impact on average system losses relative to load is to calculate the difference in total system losses with and without that generating facility across various base cases that are reasonably representative of the operating state of the system at different times of the year. Issues related to the choice of location and swingbus are addressed in greater detail by the Commission in sections 4 and 5 of this decision.

34. ATCO made a similar observation with respect to the types of concerns raised by various parties with respect to the AESO’s proposed ILF methodology.25

44. …It needs to be recognized that the AESO has to “establish a means of determining [...] loss factors and associated charges and credits, which are anticipated to result in the reasonable recovery of transmission line losses.” As recognized by legislation, there will always be a measure of forecasting, judgment calls, modeling simplifications, etc. involved in any loss factor rule. ATCO Power recognizes that participants are interested in the best and most accurate loss factor calculation possible. However, ATCO Power submits that the AESO’s proposed Line Loss Rule provides sufficient clarity, does not contain any fundamental flaws, and is unbiased. As such, the proposed Line Loss Methodology and Line Loss Rule should not be found non-compliant due to the questions raised regarding implementation and modeling issues.

35. ENMAX, for its part, took serious issue with the suggestion that the only problems with the ILF methodology were related to how it might be implemented. Instead, ENMAX challenged the fundamental validity of ILF as an approach to calculating line loss factors:26

5. ILF advocates attempt to paper over the many shortcomings and deficiencies of ILF, but the fact remains that the ILF methodology (whether by plant or by MPID) is a deeply flawed methodology. It has no theoretical support, fails to accurately reflect how an actual power system works, and starts out with a fundamental misallocation of losses, which the methodology attempts

25 Exhibit 790-X0413, ATCO argument, July 31, 2015, page 13, paragraph 44.
26 Exhibit 790-X0439, ENMAX reply argument, August 28, 2015, pages 2-3, paragraph 5.
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...to address through a series of ad hoc steps and processes that have no function other than to fix what ILF gets wrong in the first place.

3.1.2 Superposition Approach

36. ENMAX is the principal proponent of the superposition loss factor methodology, the second major loss factor methodology being considered in this module of the proceeding. Aside from TransAlta – which had previously supported ILF by plant, but now favours superposition – all other parties oppose adoption of this proposed alternative to the current Line Loss Rule.

37. According to ENMAX, the superposition loss factor method is based on the superposition theorem. It summarized the latter in the following terms:27

In any electric network, the element voltages and currents are the effects produced by the applied sources, which are regarded as the causes. If the network has several sources, each element voltage and current can be considered to be the sum of several components, each component produced by one of the individual sources. The principle of superposition, when applied to constant-resistance circuits, states that the current or voltage in any branch produced by several applied sources acting together is the algebraic sum of the currents or voltages produced in that branch by each source acting separately.

38. Part 4 of ENMAX’s written argument is titled, “Superposition in a Nutshell.” The first two paragraphs of that section provide a very high level, non-mathematical description of the superposition methodology and how it purports to calculate line loss factors:28

21. Imagine that you are conducting a survey. Your interest is the net number of cars of each colour moving from north to south along a highway. When you see a blue car headed south, you increase the blue count by one. When you see a red car headed north, you decrease the red count by one. The total north-to-south flow is simply the blue count, plus the red count, plus the green count, and so on. If more cars of certain colours are heading north than south, those counts will be negative.

22. Superposition is, in effect, the survey-taker where the “highway” is a transmission line and the “cars” are electrons. Each generator injects electrons of its own “colour.” By counting the electrons from each generator that are flowing on each transmission line, we can accurately determine the contribution of each generator to transmission system losses. So, while the mathematics of superposition may be complex, the concept is simple.

39. TransAlta summarizes the principal features, assumptions and operating characteristics of the superposition methodology as follows:29

121. At its base, Superposition is a simple method. Using well established engineering principles, the Superposition Method isolates each generating unit’s effect on power flows and the associated contribution to system losses. The Superposition methodology recognizes that the current or voltage in any transmission network branch is the algebraic sum of each of the currents or voltages produced by each source acting separately. Using the AESO’s load flow software, superposition breaks each network voltage and current

27 Exhibit 790-X0439, ENMAX reply argument, August 28, 2015, page 7, paragraph 18.
into its component parts, and then uses each of those parts to allocate losses to generating units on the system that are subject to line-loss charges or credits.

122. The Superposition Method determines a generating unit’s contribution to system losses based on three steps:

(a) Assess how each generating unit’s full injection is distributed by the system topology to serve loads;

(b) Assign a credit to a generating unit for reducing flow on a transmission element and assign a charge to a generating unit for increasing flow on a transmission element; and

(c) Aggregate the credits and charges to determine a generating unit’s contribution to system losses, and divide this aggregate by the generating unit’s injection to derive a raw loss factor.

123. The Superposition Method does not make any assumptions about which loads are served by which generating unit. It assesses how power flows according to the impedances of transmission elements. This recognizes that power takes the path of least resistance, and that a generating unit will serve a higher proportion of electrically-close loads than electrically-distant loads.

124. The Superposition Method also doesn’t make any assumptions about what unit of flow is being caused by a generating unit. Instead it uses an incremental average methodology that allocates the same amount of losses for each unit of flow contributed by a generating unit. For example, if a generating unit contributes 10 MW of flow on a line and a second generating unit contributes 1 MW of flow on the same line, the first generating unit is found to have contributed ten times more to system losses than the second generating unit. This is consistent with the fact that it is impossible to determine which generating unit contributes the first or last units of flow on a transmission element.

125. Superposition does not alter the base case to calculate loss factors. It does not alter system conditions such as voltage, loads and reactive power flows that have been demonstrated to affect system losses. Superposition also does not require any judgment to determine whether these quantities have changed in analytically acceptable ways because it does not change those quantities.

40. As both ENMAX and TransAlta make clear, it is a fundamental attribute of the superposition methodology that “all generating units at the same location are assessed the same loss factor.” According to ENMAX, this is because “there is no way for the transmission system to distinguish between co-located units. As such, all co-located units must have the same RLF [raw loss factor] in any dispatch scenario, which is what superposition leads to.” [emphasis in original]

41. A closely related point made by both ENMAX and TransAlta is that the superposition methodology is an “average incremental methodology” that considers “the full range of each generating unit’s output” because it “averages the incremental line-loss impacts of each

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30 Exhibit 790-X0416, TransAlta argument, July 31, 2015, page 36, paragraph 126.
31 Exhibit 790-X0411, ENMAX argument, July 31, 2015, page 9, paragraph 47.
generator over all possible orders in which the unit could have been dispatched” in each base case operating state. It is this operating characteristic of the superposition methodology that leads ENMAX to further claim that the “superposition-based allocation could actually be considered the ultimate ‘average megawatt in’ approach.”

42. In ENMAX’s words, the superposition methodology can be distilled to the following two propositions: 

27. Ultimately, the superposition method is based entirely on three things: (1) the solved load flow equation; (2) the definition of complex electric power; and (3) the rules of matrix algebra...

and

129(c) The superposition method is based on two very simple notions: (1) that we can use the superposition theorem to tell us where each generator’s electrons go; and (2) that each electron that flows in a transmission element is equally responsible for the power loss in that branch...

43. ENMAX claims that, when considered in its totality, the proposed superposition methodology “meets all of the legislative requirements, has a solid theoretical foundation, respects the laws of physics, and is operationally efficient.”

44. Although different parties took issue with different aspects of superposition, all parties that were critical of this methodology claimed that its shortcomings were individually and collectively sufficient to render it non-compliant with the Electric Utilities Act and the Transmission Regulation.

45. The Commission’s overriding preliminary concern in Module B of this proceeding is to determine whether one, or both or neither of the two major proposed alternatives to the current Line Loss Rule complies with the legislation and regulation. No further attention need be paid to any proposed loss factor methodology that does not meet this important threshold. The Commission, therefore, takes note here of only a subset (consisting of the most salient) of the alleged inconsistencies or sources of non-compliance between ENMAX’s proposed loss factor methodology and the governing legislation and regulations identified by parties opposite in interest.

46. Much of the debate in this proceeding has centred on the question of whether superposition complies with sections 19(1)(a) and 19(2)(d) of the Transmission Regulation. With respect to the latter provision, the focus has resided primarily on the meaning of the term “impact.”

47. ATCO, for example, takes the position that:

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34 Ibid., page 9, paragraph 45.
35 Ibid., page 5, paragraph 27.
36 Exhibit 790-X0439, ENMAX reply argument, August 28, 2015, page 46, paragraph, 129.
37 Exhibit 790-X0411, ENMAX argument, July 31, 2015, page 2, paragraph 12.
“Impact” is inherently a measure of change and any analysis of an impact must involve two scenarios.

To determine the impact of a generator on system losses, one needs two operating states: an “actual state” (with the generator) and a “hypothetical state” (without the generator). The hypothetical state has nothing to do with operating state changes over time and as such neither past nor future operating states influence the impact. That the hypothetical state is likely to never exist is irrelevant. The hypothetical state reflects a world in which the owner of the generator decided to shut down his unit. Losses in that world would be different. The difference between losses in that world and actual losses would be a direct consequence of the shutdown decision. It therefore reflects the cost/benefit caused by the decision and as such is the efficient signal for the decision maker.

48. Of the two principal loss factor methodologies under consideration in this module of the proceeding, only the ILF methodology or ‘but-for’ approach to calculating line loss factors considers each observed state of the transmission system (i.e., each base case) with and then without each generating facility in order to determine loss factors that are representative of each generating facility’s “impact” on average system losses relative to load. ATCO urges the Commission to find on this basis that an ILF methodology is consistent with the requirements of the Transmission Regulation while the superposition methodology is not. ENMAX, meanwhile, vigorously contests that the Transmission Regulation (whether Section 19(1)(a) or 19(2)(d)) in any way implies or requires that a ‘but-for’ approach be employed to determine line loss factors for the following reasons:

76. There are several crucial differences between the superposition method and the LFA.\textsuperscript{39} One is that, as explained above, the superposition method uses the \textit{average incremental impact over all possible dispatch orders} to calculate RLFs [raw loss factors]. Since the average is computed algebraically and “baked in” to the superposition method (via the allocation equation \(L_k = v_i\) and its mathematical equivalents) there is no need for numerical averaging and no need for separate operating states for each and every loss factor.\textsuperscript{40}

\[ \ldots \]

46. The superposition method relies, for any complete set of raw loss factors, on one and only one operating state. Reliance on a single operating state is the only way to comply with the requirement that loss factors be representative of a generator’s contribution to system losses as the term must be understood in light of previous Commission findings… The power loss on the transmission system \textit{right now} depends on conditions \textit{right now}. There are no terms in the power equation \(p(t) = v(t)i(t)\) relating to any past or future time or to what losses would have been “but for” the output of a particular generator. Nor is there any reference in any applicable act or regulation to “but for” analysis or “retirement signals.” The only meaningful number for the purposes of line-loss calculations is the difference between total injections and total withdrawals, measured simultaneously.\textsuperscript{41}

\[ \ldots \]

\textsuperscript{39} The AESO has proposed an ILF methodology that it calls the Load Flow Approach (LFA).
\textsuperscript{40} Exhibit 790-X0069, ENMAX evidence, March 12, 2015, page 30, paragraph 75.
\textsuperscript{41} Exhibit 790-X0411, ENMAX argument, July 31, 2015, page 9, paragraph 46.
53. …The difference between total injections by generators and total withdrawals by loads is completely meaningless if the two are not measured at the same time—that is, in a single operating state…

49. And in reply argument ENMAX stated:

53. …EEC [ENMAX] notes that nowhere in the Transmission Regulation does it state that loss factors are to reflect the impact of adding or removing a generator. What is does say is that loss factors must be based on generators’ respective locations and contributions to transmission losses, and the evidence clearly shows that superposition does this, while ILF does not.

50. Like ATCO, Medicine Hat takes issue with the claim made by proponents of superposition that their preferred methodology measures the “incremental impact” on line losses of each generating unit. According to Medicine Hat, the fact that superposition considers all possible dispatch orders that could have resulted in a generating unit’s base case output does not mean that it measures the “impact” of each generating unit on average system losses as understood by the Commission and as required by Section 19(2)(d) of the Transmission Regulation:

78. The reason EEC makes no mention of load scaling (or a balancing swing bus of any form) in the examples used to illustrate the AADOII method is that none is involved because EEC is not attempting to genuinely calculate “incremental impacts” (system losses with and without the pertinent generator). Instead, it is attempting to deconstruct and assign power flows within a single distinct operating state (rather than measuring how a change in power flow changes the amount of system losses). It does this by first freezing the operating state in the form of linear equations based on voltages and currents (i.e. the superposition representation) then designating a proportion of the power flow on each transmission line to respective generators.

79. EEC attempts to paint this method as a calculation of a generator’s “impact:”

45. Once superposition has been used to “count the electrons” (i.e., trace the current flows) from each generator, it uses the circuit-theory equation for losses—with no double-counting—to compute the losses due to each generator on each transmission line. In addition to using the power-loss equation directly, the same allocation equation can be arrived at in several other ways, including:

(a) by averaging generators’ incremental impacts over the infinite number of dispatch orders in which the units could have achieved the given operating state;

(b) by assuming that all units ramped up simultaneously into that state;

(c) by calculating the impact that each generator’s injection has on the actual ac waveform—i.e., a generator’s instantaneous impact on voltages and currents. [Bolding and underlining added.]

\[\text{Ibid., page 10, paragraph 53. The Commission notes here that ENMAX appears to suggest that an ILF methodology that examines different states of the system (i.e., one with and one without each generating facility) must do so at different times for each base case. This, however, is not the case, as was explained by ATCO at paragraphs 42-44 of its reply argument.}\]

\[\text{Exhibit 790-X0439, ENMAX reply argument, August 28, 2015, page 20, paragraph 53.}\]

\[\text{Exhibit 790-X0428, Medicine Hat reply argument, August 28, 2015, page 16, paragraphs 78-80.}\]

\[\text{Medicine Hat refers to the superposition methodology here as the “average of all dispatch order incremental impacts” or AADOII method.}\]
80. But EEC’s characterisation is misplaced. The Commission has clearly held in two Decisions that a generator’s “contribution,” and hence its “impact,” on system losses requires the determination of the change in system losses (i.e. “added to or lowered”) over the full range of a generator’s output. It is a rudimentary mathematical truism that to measure the change in anything, let alone system losses, one must compare the object (the “thing”) under two different conditions. It should therefore be of no surprise that the Commission’s findings on the measure of “contribution” requires the comparison of system losses at two different operating states (e.g. with and without the pertinent generator) and to do otherwise is contrary to the Commission’s findings in Decision 2012-104 and Decision 2014-110.

51. In other words, Medicine Hat argues that superposition falls short of what is required by the Electric Utilities Act and the Transmission Regulation because it is not, in fact, an average incremental methodology. Superposition does not measure a given generating facility’s impact on average system losses since it does not actually compare system losses in two different operating states – one with and the other without each generating facility in question for each base case under consideration.

52. The AESO maintains that the superposition methodology fails to comply with the governing legislation and regulations, as well as prior Commission decisions, on the following two grounds: (1) “it does not assign losses reflective of the full range of a generating unit’s output;” and (2) “it does not allocate losses to the generating unit that causes them.” The AESO elaborated on these two alleged flaws in the superposition methodology in its argument and in reply argument as reproduced below:

31. EEC states that superposition “is consistent with the Commission’s direction to base loss factors on the full output of each generating unit [emphasis added].” However, notably, EEC mischaracterizes the Commission’s finding in Decision 2014-110 that: “...Section 19(1)(a) [of the Transmission Regulation] requires recognition of the effects of the full range of a generating unit’s outputs [emphasis added].”

32. In other words, loss factors must reflect the full range of outputs of a generating unit, not the single point of its full output as stated by EEC. The failure of superposition to reflect the full range of outputs of a generating unit is the primary reason why it is not compliant with the relevant legislation.

33. TransAlta claims that superposition accurately determines a generating unit’s contribution to and impact on system losses, because it considers the full range of a generating unit’s output. That is also not correct. As acknowledged by EEC, superposition deals with conditions “right now”. As a result, it cannot reflect the full range of a generating unit’s output. As stated by the AESO in its argument, superposition cannot address any generating unit’s output other than the output “right now”.

34. EEC states that “a simple non-electricity example, for which we know the correct allocation of losses with certainty, shows that the use of multiple states is neither correct nor necessary [emphasis in original].” EEC then goes on to provide an analogy of diesel fuel being transported by truck.

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46 Exhibit 790-X0409, AESO argument, July 31, 2015, page 15, paragraph 65.
48 Exhibit 790-X0437, AESO reply argument, August 28, 2015, pages 7-8, paragraphs 31-38.
35. However, EEC’s analogy suffers the same flaw as superposition, in that it allocates losses at a particular state rather than over the full range of output. In EEC’s analogy, if one of the trucking companies no longer operated (perhaps fuel was now delivered to its customers by pipeline or by rail), the losses on the system would decrease non-linearly and the remaining companies would incur different losses per unit.

36. Whether in EEC’s analogy or on the transmission system, the impact on losses of any individual loss causer varies non-linearly over the full range of its output. That impact cannot be measured at a single state and cannot be appropriately allocated by superposition. Rather, considering the impact over the full range of output requires losses to be assessed at more than one state. ILF is the only methodology put forward in this Proceeding which does that.

37. Further, EEC states that, in superposition: “...if a generator is added the system’s operating state changes...it is expected that all generators’ loss allocations would change [emphasis in original].” This is contrary to the Commission’s finding in Decision 2014-110 where it held: “A generating unit should ... receive the full benefits of the system loss savings caused by its operations.”

38. In other words: “Section 19(1)(a) [of the Regulation] requires a measure of ‘contribution, if at all’ that includes a measure of the full value of both losses caused and losses saved by a generating unit.” The Commission held that: “Failure to meet this requirement results in an undue preference being granted to loss causers and an unjust discrimination against loss savers.”

53. Medicine Hat raises a very similar objection to superposition in its reply argument:49

In effect, the AADOII method [i.e., superposition] abandons the assessment of the quadratic impact on losses due to the full range of a generators output and, instead, relies on a “splitting the pie” concept whereby allocations are made in proportion to the current from each generator that is tracked across each line for a given operating state of the system (i.e. base case). The City submits that this method is nothing more than an advanced form of flow tracking. It allocates losses at one point on the line losses curve using a single ratio of outputs and in doing so it ignores the extent to which the pertinent generator added to or lowered system losses over the full range of its output, (i.e. it ignores the MLL [marginal line loss] curve over the full range of its output) which is inconsistent with the Commission’s findings on the measure of Contribution and the principles of cost causation and efficient pricing.

54. There was also much debate between supporters and opponents of the superposition methodology on how the common term in the line loss equation in the two generator case (and, by extension, the multiple generator case) should be allocated between generating units. The issue in this discussion was whether superposition allocates the common term in a manner consistent with the requirements of the legislation and regulations, or whether, as opponents of superposition claim, the allocation is without economic justification, if not entirely arbitrary. ENMAX defended the equal allocation to each generator of the line losses represented by the common term(s) in the line loss equation on the grounds that (1) this accords with the laws of physics; (2) this is consistent with the principle of cost causation; and (3) as the number of common terms increases rapidly into the many thousands, “there is no way to set that many different β’s [unallocated loss shares] in any fair or rational way. So... [allocating shares

49 Exhibit 790-X0403, Medicine Hat argument, July 31, 2015, page 49, paragraph 174.
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equally] again makes sense. Also, allocating shared terms equally has a sound physical interpretation in both dc and ac cases…

55. Milner, ATCO and other parties took the position that the only economically rational and defensible way to split (i.e., allocate) the common term(s) in the line loss equation was to allocate them 100% to each generating unit (on the ground that beyond those line losses that can be directly attributed to each generating unit, each such unit also contributes indirectly (but indeterminately) to aggregate line losses on the system) and then proceed to calculate a single annual loss factor for each pursuant to the AESO’s proposed line loss rule. Opponents of superposition argued that the allocation method “baked into” the proposed superposition loss factor methodology was inherently arbitrary, violated the cost causation principle and, accordingly, was unjustly discriminatory, unduly preferential and contrary to the Electric Utilities Act and the Transmission Regulation.

56. It has also been argued by opponents of ENMAX’s proposed loss factor methodology that it is largely a mathematical and physics-based construct with little or no meaningful economic content. ENMAX itself concedes that “(s)ince physics has nothing to say about annual (as opposed to RLF) loss factors, they should be based on operational and economic considerations and could be different even for co-located units.” At the same time, however, ENMAX makes the point that “(f)or clarity, EEC acknowledges that there are no costs (at least as measured in dollars) at the RLF stage. What we are really dealing with here is ‘loss’ causation. Of course, we could never get the cost causation right if we didn’t get the loss causation right in the first place.”

57. ENMAX went to considerable lengths to rebut each alleged shortcoming or flaw in its superposition methodology as advanced by parties opposite in interest. It summarized its position with respect to all alleged deficiencies of the superposition methodology in the following terms:

8. The superposition method is the inescapable outcome of combining the load-flow equation and the line-loss equation. The method is physically meaningful, mathematically correct, consistent with previous Commission findings, and in full compliance with the laws of Alberta. It is an “incremental” method in which the incremental impact that each generator has on system losses is averaged over all possible dispatch orders that could have resulted in the operating state for which RLFs are being calculated. Importantly, there are other, equally valid interpretations of the superposition method that demonstrate the robust link between superposition RLFs and power-system physics. The “mountain of mathematical formulae and proofs” provided by EEC in this proceeding gave superposition’s opponents plenty of opportunity to point out flaws in the method’s derivation, yet the mountain stands unscarred. [emphasis in original]

9. The superposition method, as advanced by EEC in this proceeding, is superior to all variants of the ILF methodology by every measure. The superposition method is more numerically stable than ILF, requires no manual intervention or unsupportable ad hoc procedures, and is more efficient. All of the challenges to it, as set out in the arguments of its opponents, are readily shown to be without merit. The superposition method itself is...

51 See, for example, exhibit 790-X0413, ATCO Power argument, July 31, 2015, pages 6-7, paragraphs 18-25; and exhibit 790-X0417, Milner argument, July 31, 2015, paragraphs 135-139.
52 Exhibit 790-X0411, ENMAX argument, July 31, 2015, page 9, paragraph 46.
53 Exhibit 790-X0439, ENMAX reply argument, August 28, 2015, page 11, footnote 29.
54 Ibid., pages 3-5, paragraphs 8-12.
well defined and has not changed in the four years since it was first put forward in this proceeding; to the extent there are issues still to be resolved, they lie with the ISO loss factor rule rather than with the method. [emphasis in original]

11. What is especially noteworthy about the arguments submitted by ILF supporters is that they contain nothing resembling a coherent, physically meaningful, and mathematically robust case. ILF remains an ad hoc collection of procedures that have no theoretical support, that rely on the existence of abnormal and mostly never-to-exist system conditions, that conflate the line-loss impact of generators with many other factors, and that depend on a construct that is a physical impossibility. …

12. With all due respect, EEC submits that a finding in favour of ILF would amount to a finding that we can ignore basic physics and mathematics when attributing system losses to generators. While neither the Electric Utilities Act nor the Transmission Regulation expressly tell the AESO to adhere to the laws of physics when designing rules, Alberta’s legislators would never have felt the need to put so obvious a requirement into legislation. In any case, it is simply not possible to determine the respective contributions of generators to transmission line losses, or to uphold the principle of cost causation, without regard to the physics that governs power system behaviour. The superposition method is the only reasonable choice.

58. Notwithstanding ENMAX’s confidence that superposition complies with applicable legislation and regulation, is mathematically and economically meaningful and robust, and is the only defensible line loss factor calculation methodology brought forward for the Commission’s consideration in this proceeding, ENMAX nevertheless conceded that its proposed methodology still requires considerable refinement before it is ready to be employed by the AESO. It pointed out at the same time, however, that this reservation applies equally to any variation of the ILF methodology that the Commission may be considering approving.55

10. …TCE [TransCanada]… goes on to state that, if superposition were to be adopted, a considerable amount of work, time, and consultation is still likely required for the AESO and market participants to gain sufficient knowledge to confirm the model has been developed properly and that the results are accurate and can be reproduced. EEC submits that the superposition method itself is robust, stable, and solidly supported by physics and economics, but agrees with TCE that there is still work to be done. As discussed in Part V below, a significant amount of work remains regardless of which methodology the Commission approves.

3.2 Commission findings regarding raw loss factor methodology

59. As noted previously, the Commission’s overriding concern at this stage of the proceeding is to determine whether one, or both or neither of the two major proposed alternatives to the current Line Loss Rule complies with existing legislation and regulation. All that is necessary for a methodology to be removed from further consideration is a single finding, on whatever grounds, that it fails to comply – and cannot be remedied so as to comply – with the Electric Utilities Act and Transmission Regulation. It is important to observe in this regard that compliance does not require perfection, even if such could be defined in these circumstances. Rather, all that is necessary is a finding that a proposed methodology is reasonably capable of meeting the legislative and regulatory requirements. It may well be that further refinements to a compliant methodology could improve its operational effectiveness, cost and ease of use.

predictability and replicability. None of these improvements is of any consequence, however, without a prior determination that the methodology itself is compliant or is reasonably capable of being made compliant.

60. Each of the variations of the ILF methodology (i.e., by unit or MPID and by plant or system bus) and ENMAX’s superposition methodology was supported by a considerable body of evidence and argument. Several expert and highly qualified witnesses also testified before the Commission. Having considered and weighed this body of evidence and divergent opinion regarding the fundamental nature, attributes and strengths and weaknesses of the two principal competing loss factor methodologies in terms of their ability to produce line loss factors that comply, or are reasonably capable of complying with the aims and objectives of the governing legislation and applicable provisions of the Transmission Regulation, the Commission finds as follows.

61. First, an ILF methodology is reasonably capable of producing a line loss rule and of calculating line loss factors that are not unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory nor inconsistent with or in contravention of the 2003 Electric Utilities Act, subsequent amendments thereto and the relevant provisions of the 2004 and 2007 Transmission Regulation dealing with line losses. This is because the ILF methodology, by definition, provides a measure of both the direct and indirect line losses and line loss savings of each generating facility across the full range of each generating facility’s output. An ILF methodology also produces line loss factors that are representative of the impact on average system losses of each generating facility relative to load, precisely because it measures the difference in average (or total) system line losses with and without each generating facility.

62. Second, the superposition loss factor methodology proposed by ENMAX fails to comply with the governing legislation and applicable regulations and is incapable of being remedied so as to comply under any reasonable interpretation of these statutory and regulatory enactments.

63. Before turning to its specific reasons for finding ENMAX’s superposition methodology to be non-compliant with the Electric Utilities Act and the Transmission Regulation, the Commission notes here the following key findings made in Decision 2014-110 as to why the current Line Loss Rule is unlawful: 56

99. A useful summary of the AESO’s views on how line loss savings are created and how credit for those savings is assigned to different generating units under its 2005 Line Loss Rule can be found in the AESO’s responses to the comments submitted by various parties during the industry-wide consultations that ultimately led to the adoption by the AESO of the MLF/2 line loss methodology. The AESO, for example, makes it clear that the locational decisions made by generators are an important driver of line loss savings on the AIES. In particular, whenever new generation is located close to a load centre, provided that the new generation capacity does not exceed the load at that load centre, line loss savings will result. Savings are created because the output from the generating unit that located close to the load centre is associated with lower line losses than the output from elsewhere on the system that previously met the demand for power at that load centre. According to the AESO, however, credit for the reduction in line losses resulting from the locational decision of the generator in question should be apportioned among all generating units on the system in relation to their capacity, rather than being attributed in full to the generating unit now supplying (some or all of) the load in close

proximity to it. In the AESO’s view, this outcome is justified on the ground that “as all
generators were originally being charged for losses, all generators will also share the
credit for the loss reduction.” The AESO’s 2005 Line Loss Rule, in other words, allocates
to line loss causers what the review panel has described in Diagrams #2 and #3 as the
“unattributed savings” of the generating unit responsible for all of the line loss savings in
question. This amounts to a socialization of the positive externalities that are created
whenever new generating units lower average system losses by locating close to load. It
also diminishes the competitive advantage (in terms of lower line loss costs) that would
otherwise accrue to generating units making efficiency-enhancing locational decisions.

…

115. The AESO’s characterization of how the 2005 Line Loss Rule satisfies the
legislative requirements focusses on Section 19(2)(d) and does not address Section
19(1)(a). The review panel recognizes that the AESO does not see much difference
between the requirements of Section 19(1)(a) and 19(2)(d). In addition, the AESO has
consistently stated that a marginal approach is what best captures impact within the
meaning of Section 19(2)(d). The review panel, however, has found that Section 19(2)(d)
must be interpreted to accord with Section 19(1)(a), which requires that the ISO maintain
loss factors for each generating unit based on their contribution, if at all, to transmission
line losses. In the review panel’s view, and as explained in section 4.1 above, Section
19(1)(a) requires recognition of the effects of the full range of a generating unit’s outputs.
A generating unit should, therefore, receive the full benefits of the system loss savings
caused by its operations.

116. There was considerable evidence presented by parties to the proceeding on the
operation of the line loss rule, demonstrating that the AESO’s MLF/2 methodology does
not attribute to line loss savers the full measure of savings they are responsible for having
created. As noted earlier, the AESO itself confirmed that a portion of the line loss savings
that arise when a generator locates close to load and produces up to but not beyond the
output required to meet that local load (referred to above as the “unattributed savings”) is
treated by the 2005 Line Loss Rule as a benefit to be shared by all generating units rather
than being credited in full to the generating unit causing those savings. As a consequence,
the loss factors assigned to loss causers are lower than they would otherwise be given the
losses they have created.

117. The AESO also explained that credit for the reduction in line losses resulting from
the locational decision of a generator in question will be apportioned among all
generators on the system in relation to their capacity, rather than being attributed in full to
the generator now supplying (some or all of) the load at the local load centre. The fact
that the 2005 Line Loss Rule distributes some loss savings to loss causers who have not
contributed to loss savings is arbitrary and means that the principles of cost causation
have been violated.

118. As noted above, the AESO considered this distribution of loss savings to be
justified on the ground that “as all generators were originally being charged for losses, all
generators will also share the credit for the loss reduction.” In the review panel’s view,
this reason cannot justify the AESO’s decision to distribute the savings as it has done.
This is so because, as discussed above, Section 19(1)(a) requires a measure of
“contribution, if at all” that includes a measure of the full value of both losses caused and
losses saved by a generating unit. The AESO’s MLF/2 methodology does not meet this
requirement. Failure to meet this requirement results in an undue preference being
granted to loss causers and an unjust discrimination against loss savers.
119. The AESO’s 2005 Line Loss Rule also does not distinguish between generating units that add to total and average line losses at every level of their output and generating units that remain net contributors to total and average line loss savings despite having commenced adding to total and average line losses only with their last (marginal) unit(s) of output. Whenever this situation occurs, the AESO’s 2005 Line Loss Rule will treat differently generating units adding the same net amount to line loss savings. One of these generating units will receive a credit under the AESO’s 2005 Line Loss Rule for every unit of its output, and the other will receive a charge for every unit of its output.

…

121. To summarize, for the reasons given in this decision, the review panel concurs with the hearing panel’s finding that the AESO’s MLF/2 line loss methodology does not comply with sections 19(1)(a) and 19(2)(d) of the 2004 Transmission Regulation because the AESO’s 2005 Line Loss Rule fails to assign to each generating unit a line loss charge or credit (i) based on each generating unit’s contribution to transmission line losses and (ii) that is representative of each generating unit’s impact on average system losses relative to load. As the majority stated in Decision 2012-104, the MLF/2 methodology is unjust because it disadvantages loss savers and does not properly charge loss creators for their losses. It is also “unjustly discriminatory as it violates all the principles of rate design that would normally be observed in a regular rate or tariff proceeding.”

64. Bearing the above in mind, the Commission’s reasons for finding the superposition loss factor methodology to be non-compliant are as follows:

- Much like the unlawful MLF/2 loss factor methodology, superposition fails to recognize a generating facility’s contribution to total line losses across the full range of that generating facility’s output as the Commission has previously found to be required by section 19(1)(a) of the Transmission Regulation. Instead, superposition, by its very nature, is limited to estimating the contribution to line losses of each generating facility at only that level of output it is generating in each base case under consideration. The result is that generating facilities will not receive the full benefit or bear the full burden of the line loss savings or line loss costs attributable to the entirety of their operations. As the Commission has previously determined, “Section 19(1)(a) requires a measure of “contribution, if at all” that includes a measure of the full value of both losses caused and losses saved by a generating unit… Failure to meet this requirement results in an undue preference being granted to loss causers and an unjust discrimination against loss savers.”

- Closely related, because superposition considers only a single operating state at any instant, it is incapable of producing a loss factor in each location that is representative of the impact on average system losses by each respective generating unit or group of generating units relative to load. In particular, superposition produces loss factors without assessing line losses on the transmission system with and without each generating facility as is inherently required by section 19(2)(d) of the Transmission Regulation. As several parties have argued, “impact” refers to the change between two different states, something which superposition is unable to measure.

- A further shortcoming in the superposition methodology is that it does not allocate losses to the generating unit that causes them. Instead, superposition takes a rather more rigid, formulaic approach in calculating line losses by assigning unattributed savings or losses
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(or what has been referred to in this proceeding as the “common term” in the line loss equation) on an equal basis to generating facilities injecting power into the same transmission element. In all but a few simple and relatively straightforward examples, this arbitrary allocation rule is likely to result in a socialization of line loss costs and line loss savings contrary to the economic and rate-making principle of cost causation. In other words, the manner in which superposition allocates line loss savings and line loss costs attending changes in the output (including the new entry or exit) of a generating facility is reminiscent of what takes place under the MLF/2 methodology. As the Commission observed in Decision 2014-110, “(a)ccording to the AESO…credit for the reduction in line losses resulting from the locational decision of the generator in question should be apportioned among all generating units on the system in relation to their capacity, rather than being attributed in full to the generating unit now supplying (some or all of) the load in close proximity to it. In the AESO’s view, this outcome is justified on the ground that “as all generators were originally being charged for losses, all generators will also share the credit for the loss reduction.”

The Commission found the AESO’s approach to be unlawful in Decision 2014-110 and the Commission finds on a similar or analogous basis in this proceeding that ENMAX’s proposed loss factor methodology is likewise non-compliant.

As a result, the Commission concludes that superposition will produce loss factors that are unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory and inconsistent with or in contravention of applicable legislation and regulation.

Accordingly, the Commission directs the AESO to change provisions of the Line Loss Rule to implement an ILF methodology using the Load Flow approach as directed below.

4 THE DEFINITION OF LOCATION

4.1 The definition of location is an important consideration for loss factors

When calculating loss factors using a margin-based methodology, such as the MLF/2 approach embodied in the AESO’s current Line Loss Rule, the definition of location is not a matter of overriding concern or consequence. As TransCanada noted in its argument, it was not even necessary for the Commission to define location in either Decision 2012-104 or Decision 2014-110 in order to determine that the current MLF/2 Line Loss Rule does not comply with applicable legislation and regulations.

By comparison, the definition of location is critically important when an increment-based line loss factor methodology is employed. By its very nature, an ILF methodology requires that the full range of output of each generating facility be taken into consideration in calculating each generating facility’s raw line loss factor. This requires that a comparison be made between two different states of the transmission system – one with the generating facility in question operating at its expected level of output and one with that generating facility no longer on the system (i.e., operating at zero output). The raw loss factor for each generating facility for each base case will be the ratio of (1) the difference in total system line losses with and without that generating facility.

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58 Exhibit 790-X0419, TransCanada argument, July 31, 2015, pages 18-19, paragraph 47.
facility and (2) total system losses with that generating facility operating at its expected level of output.

68. The importance of how location is defined when an ILF methodology is employed to calculate line loss factors becomes clear whenever generating facilities are physically located in close proximity to each other and, even more so, whenever they are co-located on the electric system. If two or more generating facilities are defined as occupying the same location then, under an ILF methodology, their output can be aggregated for purposes of calculating a single loss factor. In practice, given the quadratic relationship between line losses and output, this means that aggregated generating facilities can, and frequently will, receive a more favourable line loss factor than if each were defined as occupying a separate location. As all parties have observed in this proceeding, this means that a generating facility consisting of either one 200 MW generating unit or two separate 100 MW generating units continuously operating at full capacity at a single location will always receive a lower line loss factor under the ILF methodology than two adjacent 100 MW generating facilities each of which is deemed to be at a separate location, even if they are also running continuously at their respective full capacity of 100 MW each. Under an ILF methodology, both location and size (or, more accurately, aggregate level of output) matter.

4.2 The legislation and the definition of location

69. Among the sections of the Transmission Regulation most frequently cited by various parties to this proceeding with respect to how location should be determined are the following:

31(1) The ISO must make rules to

(a) reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors

(i) for each generating unit,

\[\ldots\]

based on their respective locations and their respective contributions, if at all, to transmission line losses.

\[\ldots\]

(c) establish a means of determining, for each location on the transmission system, loss factors and associated charges and credits, which are anticipated to result in the reasonable recovery of transmission line losses,

\[\ldots\]

31(2) In accordance with the rules made under subsection (1), the ISO must determine loss factors having regard to the following:

\[\ldots\]

(d) the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load;
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(e) the loss factor must be one number at each location that does not vary...

70. The ISO rules define transmission system losses as “the total of the transmission system losses on the interconnected electric system.” The *Electric Utilities Act* defines transmission system as “all transmission facilities in Alberta that are part of the interconnected electrical system,” and also defines transmission facility as:

(bbb) “transmission facility” means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes
(i) transmission lines energized in excess of 25 000 volts,
(ii) insulating and supporting structures,
(iii) substations, transformers and switchgear,
(iv) operational, telecommunications and control devices,
(v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy...
(vi) connections with electric systems in jurisdictions bordering Alberta, but does not include a generating unit or an electric distribution system;

71. Generating unit is defined in the *Electric Utilities Act* as follows:

(u) “generating unit” means the component of a power plant that produces, from any source, electric energy and ancillary services, and includes a share of the following associated facilities that are necessary for the safe, reliable and economic operation of the generating unit, which may be used in common with other generating units:

(i) fuel and fuel handling equipment;
(ii) cooling water facilities;
(iii) switch yards;
(iv) other items;

72. While the above definitions are helpful to define elements of the AIES, including the transmission system, they do not provide a definition of the term ‘location’ for the purposes of calculating loss factors. The term ‘location’ is nowhere defined in the *Transmission Regulation* or the *Electric Utilities Act*. Nor is it defined in the ISO rules. Given the importance of the definition of location, and the lack of consensus among parties as to its meaning, it remains one of the key matters to be determined in this module of the proceeding.

73. In Decision 2012-104, the Commission stated:

During the proceeding the exact meaning of location was argued and examined. While no specific finding on location is required subject to our decision above the Commission believes that with the development of a new line loss rule the location definition should be refined and determined. The Commission notes that when it comes to a generating unit, it is both contribution and location that are described in Section 19(1)(a) and any

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60 Decision 2012-104, April 16, 2012, paragraph 139.
definition should recognize the reality that generators in the same local can have much different affects on average system losses depending on their contribution as much as generators that contribute in the same way can have if they are located in different areas.

74. And during the oral hearing the AESO testified:\textsuperscript{64}

\begin{enumerate}
\item Q. If those three elements ask for in clause 2(a)
\item substation name and number, a legal subdivision and
\item MPID, if that's how you define point of supply, then
\item isn't essentially the physical land location of the bus
\item really being the point of supply?
\item A. MR. MARTIN: No, I don't think so. If I had to
\item pick one of those pieces of information to define the
\item point of supply, it would be the measurement point.
\item That's the point where the facilities of the market
\item participant connect to the transmission system and
\item which is metered for revenue purposes.
\item The substation name and number and the
\item geographical land location essentially help people
\item understand what -- where the connection is who may not
\item be familiar with the letters and digits of the MPID.
\item A. Go ahead.
\item A. MR. MARTIN: We have many instances where a
\item single substation serves multiple services, including
\item both load and generation services. And simply because
\item they're served at a single location, a single
\item substation or from a single bus doesn't mean there's
\item only one service. The service -- the differentiating
\item aspect on this list of three items for the service is
\item the metering point.\textsuperscript{[emphasis added]}
\end{enumerate}

75. Both the ISO rules and tariff define metered energy as “the quantity of electric energy transferred to a \textbf{point of delivery} or from a \textbf{point of supply}, in MWh, reflected by the relevant \textbf{metering equipment} during a particular period of time” and point of supply as “the point at which electricity is transferred to \textbf{transmission facilities} from facilities owned by a \textbf{market participant} receiving system access service under the \textbf{ISO tariff}, including a \textbf{generating unit} or an \textbf{electric distribution system}.”\textsuperscript{62} [bold in original, underline added] The ISO Tariff – Rate STS: Supply Transmission Services states in part:

1(1) Rate STS applies to \textit{system access service} provided at a \textbf{point of supply} to:

\begin{enumerate}
\item the \textbf{legal owner} of a \textit{generating unit} . . . or an \textbf{aggregated generating facility} that is not subject to a \textbf{power purchase arrangement};
\item the holder of the \textbf{power purchase arrangement} for a \textit{generating unit} that is subject to a \textbf{power purchase arrangement};
\item the \textbf{legal owner} of an industrial system that has been designated as such by the \textbf{Commission};
\item the \textbf{legal owner} of an \textit{electric distribution system} where a \textit{generating unit} or an \textbf{aggregated generating facility} connected to the \textit{electric distribution system} results in electricity flowing into the \textbf{transmission system}; or
\end{enumerate}

\textsuperscript{64} Tr. Vol. 1, April 16, 2015, page 151, lines 1-24.

\textsuperscript{62} ISO Consolidated Authoritative Document Glossary, effective September 1, 2015.
(e) the City of Medicine Hat.

76. The ISO rules also define source asset as “a subcategory of pool asset and means one (1) or more aggregated generating facilities, generating units, or import assets.” Further, ISO rule Section 201.5: *Block Allocation* states in part:

**Operating Block Allocation**

2(2) The ISO must allocate to each source asset:

(a) that is not an import, seven (7) operating blocks for energy and one (1) operating block for dispatch down service; and
(b) that is an import, one (1) operating block for energy with a zero dollar ($0.00) offer price.

77. The ISO rules define operating block as: “any one (1) of the seven (7) price and quantity pairs the ISO allocates to a pool asset within a settlement interval for the purposes of submitting bids and offers.”

78. From the foregoing, it is clear that for each system access service under the ISO tariff, metered energy is measured at the point at which electricity is transferred to the transmission system, which is also the point at which market participants are allocated seven operating blocks (or price and quantity pairs) for each source asset.

### 4.3 Parties views regarding the definition of location

79. In this proceeding, there are two competing interpretations of how location should be defined for use in an ILF loss factor methodology.

80. One group of parties has argued that increment-based loss factors should be calculated on a generating unit basis, which, subject to certain exceptions, is the same as the location of the MPID. When using the expected output of a generating unit as the size of the increment in an increment-based methodology, each generating unit will receive its own loss factor independent of the units in the immediate vicinity. Under an ILF by unit methodology such as that proposed by the AESO – where location is defined by the MPID – generating units of the same size that are located in close physical proximity to each other and that are operated in the same manner will be assigned essentially identical loss factors. Meanwhile, generating units that are located in close physical proximity to each other but that are of a different size and/or are operated in a different manner will be assigned loss factors that differ from each other. In an ILF by unit methodology, each generating unit is treated as a stand-alone unit.

81. In its filing in response to the Commissions August 8, 2014 letter, the AESO stated:

28. MLF/2 was applied to all generators at a single location where the location was defined as the same bus. In the proposed Load Flow approach, the choice of location has changed. For purposes of the proposed Load Flow approach, the location of a generator or group of generators will be the unique MPID. By moving the location at which a generator’s contribution to losses is measured further upstream from the bus, the

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63 Exhibit 563.02, AESO filing in response to the Commission’s August 8, 2014 letter, December 4, 2015, pages 11-12, paragraphs 28-30.
proposed Load Flow approach removes the potential for discrimination between generators that may be connected to the same bus but that have different impacts on system losses. [emphasis added]

29. A common hypothetical illustration is a base load unit and a peaking unit connected to the same bus. When the bus is the location at which losses are measured, these different units would have the same loss factor; when the location is the MPID, these units would have different loss factors that, in theory, would be closer to the generator’s contribution to transmission line losses, and therefore more representative of the generator’s impact on average system losses relative to load.

30. The proposed Load Flow approach’s use of the MPID as the location, combined with the “but for” ILF calculation in the Load Flow approach, ensures that the resulting loss factors for each generator are based on its location or respective location, and its contribution or respective contribution, if at all, to transmission line losses, all as required by sections 19(1)(a) of the 2004 Transmission Regulation and section 31(1)(a) of the 2007 Transmission Regulation. The proposed Load Flow approach also reasonably ensures that each generator receives credit for its offsetting contribution to system losses up to the point where output from that generator no longer offsets losses, and charges a generator for its contribution to system losses beyond that point.

82. Milner provided a number of reasons in support of the AESO’s proposed ILF by unit methodology and associated definition of location: ⁶⁴

91. Measuring each generator’s contribution to losses on an individual basis at its meter and where its energy output is also measured, removes the potential for discrimination between generators that may be connected to the same bus but that have different impacts on system losses. Generators connected to a common system bus can have different impacts on system losses due to differences in generator size, dispatch levels and dispatch patterns. Unnecessarily aggregating generators that connect to a common bus masks their different contributions to average system losses and lowers the loss charges to these generators relative to others. Essentially, if location is assessed at the bus, a generator’s loss factor will be based more on the contribution to losses of other generators at its bus or even at nearby buses than it is on the generating unit’s own contribution to system losses. This will have a distorting effect on market signals as the impact on transmission losses will not be fully reflected in the loss charges or credits that each generator receives.

…

93. It is clear that using a generators MPID best reflects a particular units overall contribution to total line losses on the AIES, provides the most accurate economic signals to generators and is consistent with the rate design principles of cost causation that figured prominently in the Review Panel’s determinations that MLF/2 is unjust, unreasonable, unduly preferential, arbitrary, discriminatory and inconsistent with the Legislative Requirements.

…

105. The record in the present proceeding is clear that different generating units connected to the same bus can be different sizes, can be dispatched at different times and can have different impacts on system losses. Moreover, different generating units can be

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⁶⁴ Exhibit 790-X0417, Milner argument, July 31, 2015, pages 26-30, paragraphs 91-105.
owned or dispatched by different parties. Milner submits that the locational incentive for generators should be sent to each generator on a generating unit by generating unit basis and a line loss methodology should reflect the fact that generators on the system are causing different levels of losses. The AESO’s proposal does just that. Again, to require that all generators in close proximity to each other have the same loss factor, as TransCanada and TransAlta suggest, ignores this reality, as well as the Legislative Requirements.

83. Powerex likewise supported the AESO’s definition of location and urged that it be accepted by the Commission on the following grounds:

… Measurement at the MPID permits a more accurate measurement of the losses caused by the locational and dispatch decisions of each generating unit as required by the TReg. The impact of their decisions ought not to be obscured by unnecessary aggregation of loss causation to the plant bus level. Powerex also notes that broadly speaking, employing ILF at the plant bus would unfairly benefit large generating plants that have multiple units by transferring costs to smaller generating plants and individual generators. Accordingly, Powerex agrees with the AESO’s approach of calculating losses at MPID.

84. Medicine Hat offered the following reasons in support of the AESO’s proposed ILF methodology, definition of location and proposed exception list:

87. The AESO Proposed Loss Factor Rule provides that the location for calculating loss factors must be at the respective measurement point for the point of supply (POS) or point of delivery (POD) for market participants taking service under Rate STS, DOS, XOS and IOS. Throughout the proceeding this location was referenced as the “MPID.” In its application, the AESO maintained that this method results in loss factors for each generator as required by section 19(1)(a) of the 2004 Transmission Regulation and section 31(1)(a) of the 2007 Transmission Regulation. The City submits that the AESO’s proposal is compliant with the Transmission Regulation and cost causation principles that are paramount in the design of rates.

…

90. Accordingly, setting the location for which to calculate loss factors at the MPID provides for a measure of a generator’s impact on system losses from the location where electricity is transferred to the transmission system by each generator taking service under Rate STS. The City submits that measuring each generator’s Contribution from this location is consistent with the principle of cost causation and provides for the appropriate distinction between “groups of generating units” that should attract a single loss factor and those that should attract more than one loss factor.

91. Firstly, using the MPID as the location for calculating loss factors ensures that groups of generating units that operate behind a single point of supply are treated fairly because only the net-to-grid transfers to the transmission system are used to measure their Contribution. The Proposed Rule provides for this distinction by calculating a single loss factor at the MPID for one or more generating units that are connected with load on an electric system that is not part of the transmission system, including industrial systems or electric distribution systems.

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65 Exhibit 790-X0408, Powerex argument, July 31, 2015, page 5, paragraph 15.
66 Exhibit 790-X0403, Medicine Hat argument, July 31, 2015, page 24-25, paragraph 87-93.
93. Secondly, using the MPID as the location for calculating loss factors ensures that groups of generating units that are operated in a highly integrated fashion, such as wind farms or combined cycle generation facilities, are also treated fairly because the net to grid transfers to the transmission system reflect the amalgamated output that is offered to, and dispatched for, the energy market from a single integrated project. The Proposed Rule provides for this distinction by calculating a single loss factor at the MPID for one or more generating units that are operationally interdependent.

85. Another party that broadly supports the AESO’s proposed ILF by unit methodology, with location being measured at the MPID, is ATCO. It provided a succinct summary of its position as follows: 67

The question then becomes, which definition of location furthers legislative goals. ATCO Power submits that efficiency is fostered if market participants see the harms and benefits caused by their actions. As such, definitions of location and group that reflect decision boundaries are best aligned with the efficiency objective in the Electric Utilities Act. For example, two generating units belonging to different owners should not be grouped since those owners will make independent decisions regarding their units.

86. According to ATCO, one of the key advantages of the AESO’s definition of location (once the AESO’s exception list is taken into consideration) is the flexibility it provides. Rather than requiring that line loss factors be calculated at a unique MPID for each generating unit, multiple generating units can be grouped at a single MPID if doing so advances legislative goals such as efficiency in the electrical generation market. 68

87. ATCO elaborated upon this point in its reply argument. ATCO does not oppose grouping of generating units at a single MPID or at the system bus in all circumstances. What ATCO opposes is “indiscriminately grouping units” as this “eliminates any possibility of sending efficient individual [locational] signals.” 69

88. Although TransAlta now favours superposition to any form of ILF methodology, it stated in argument that were the Commission to approve an increment-based loss factor methodology, it should be in the nature of that proposed by the AESO. 70

If the AUC does approve ILF, TransAlta submits that it should approve ILF by MPID. TransAlta initially favoured ILF by plant, because it appeared to address a number of problems with the ILF method. However, while ILF by plant addresses some of the problems created by the ILF methodology itself for some generating units, the evidence developed in this proceeding (much of which was developed after the oral hearing) demonstrates that ILF by plant creates additional significant issues in the system, by effectively increasing the level of discrimination inherent in ILF between very large generating units and smaller ones. A much lower loss factor for larger generating units measured on a plant basis means an even higher loss factor for smaller generating units.

89. A number of other parties favoured a different interpretation of location from that proposed by the AESO. In effect, it was argued by this second group of parties that location should be understood in its ordinary sense or meaning. Where one or more generating units are

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67 Exhibit 790-X0072, ATCO Power evidence, March 12, 2015, page 11, paragraph 44.
68 Exhibit 790-X0413, ATCO Power argument, July 31, 2015, pages 16-18, paragraph 57.
69 Exhibit 790-X0432, ATCO Power reply argument, August 28, 2015, page 12, paragraph 36.
70 Exhibit 790-X0416, TransAlta argument, July 31, 2015, page 42, paragraph 152.
physically co-located with each other or, more generally, have been built in close physical proximity to each other, they should be treated as being at a single location for purposes of calculating a line loss factor for those generating units. In this proceeding, grouping together or aggregating individual generating units at a single physical location for the purpose of calculating line loss factors has been variously referred to as ILF by plant, ILF by plant bus or ILF by system bus. Using the expected output of a group of co-located generating units as the size of the increment in an increment-based methodology will produce only a single line loss factor for the entire group. That is, co-located generating units, regardless of their size and how they are operated, will be treated as a single, undifferentiated generating unit and will be assigned a single line loss factor under the ILF by plant methodology.

90. The Commission notes here that the same result will obtain whenever two or more generating units are aggregated at a single MPID under the AESO’s proposed exception list. In other words, those parties favouring an ILF by plant methodology are seeking the same treatment for all generating units at the same physical location as would be accorded them under the exception list to the AESO’s ILF by unit methodology were those units subject to common ownership.

91. TransCanada supports the ILF by plant or system bus methodology and opposes the AESO’s proposed ILF by unit methodology on several grounds. TransCanada’s first objection is based on statutory interpretation. It claims that the AESO has misinterpreted key provisions of the Transmission Regulation. Specifically, TransCanada points out that while Section 19(1)(a) of the Transmission Regulation requires the AESO to establish and maintain “loss factors for each generating unit based on their respective locations and respective contributions, if at all, to transmission line losses,” Section 19(2)(d) provides that “the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load.” [emphasis added] Section 19(2)(e) then expressly mandates that “the loss factor must be one number in each location”. [emphasis added] This leads TransCanada to conclude as follows:

If the drafters of section 19(2)(d) had intended each loss factor to apply to only one generating unit (based on an Asset ID number), there would have been no need to specify that the loss factor must be one number at each location – that would have occurred automatically for each generating unit and there would have been no purpose for section 19(2)(e). The fact that “one number at each location” was specified in section 19(2)(e) can only indicate an intention that there could be one or more generating units at a location. This is also the reason that the words “generating unit or group of generating units” are used in section 19(2)(d).

92. TransCanada summarized its second broad concern with respect to the AESO’s proposed ILF by unit methodology as follows:

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72 The Commission notes that certain parties, among them TransCanada and ENMAX, have suggested that even though units aggregated at a single location would be assigned the same line loss factor, different methods could be employed to derive individual loss factors for each of those co-located units at a common bus. The Commission considers it unnecessary to discuss these proposals in view of its determinations with respect to location, as discussed further below.

73 Exhibit 790-X0419, TransCanada argument, July 31, 2015, pages 20-22, paragraph 50.
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…the ILF by MPID Method treats similarly situated customers differently without justification, is contrary to basic cost-causation principles, and leads to inefficient economic signals due to the creation of cross subsidies.74

93. TransCanada based its conclusion on an example of how the ILF by unit methodology would calculate line loss factors for different sized generating units operating at the same system bus. It put its example to Teshmont by way of an information request to confirm its understanding of how the AESO’s ILF by unit methodology would calculate loss factors in the situation described in the example.75 TransCanada elaborated on its concerns as follows:76

95. The two 100 MW generators at one location operating at full output should have the same loss factor as one 200 MW generator operating at full output at that same location since they have the identical impact on transmission system losses. They are similarly situated and should have the same loss factor since they are operated in a similar manner (i.e. full output). However, under the ILF by MPID Method, these generators would not be treated the same.

96. Following cross-examination, the AESO corrected its response to the above Information Request and confirmed that the two 100 MW generating units would be charged a 7.5% loss factor under an ILF by MPID Method whereas one 200 MW generating unit would be charged a 5.0% loss factor under an ILF by MPID Method.

97. Under these circumstances, the two arrangements of generating units have an identical impact on transmission system losses, but have very different loss factors. The loss factor calculated using ILF by MPID is 50% higher than the ILF by Plant Bus calculation. This is a clear case of discrimination for similarly situated generating units with no justifiable grounds for such discrimination.

98. This example is not a rare circumstance, but is indicative of the discriminatory nature of the ILF by MPID calculations for all large generating units at one location. If anything, this example understates the amount of discrimination that occurs when co-located generating units are not calculated on a totalized basis.

94. TransCanada’s third major objection to the AESO’s proposed ILF by unit methodology – and corresponding reason for supporting an ILF by plant bus methodology – relates to the AESO’s proposed exception list. Specifically, TransCanada expressed the concern that there appeared to be insufficient justification for grouping at a single MPID various generating units found on the exception list other than that “the MPIDs were established at different times.” According to TransCanada:77

… the definition of MPID is highly arbitrary and is unrelated to any traditional rate design considerations, such as cost causation, similar pricing for similarly situated customers, fairness, and administrative simplicity.... This suggests an unwarranted, unjustified and arbitrary decision to totalize generating unit outputs at a system bus in some cases and not totalize generating unit output in other cases.

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74 Exhibit 790-X0419, TransCanada argument, July 31, 2015, page 29, paragraph 80.
75 Exhibit 790-X0032, AESO-TCE-2015JAN08-006, PDF pages 15-17.
76 Exhibit 790-X0419, AESO-TCE-2015JAN08-006, PDF pages 15-17.
77 Exhibit 790-X0419, TransCanada argument, July 31, 2015, page 37, paragraph 111 and page 39, paragraph 118.
95. TransCanada expanded on its concerns with respect to which generating units were included in the exception list and which were not by looking into “the historical reasons why revenue meters were located (and totalized, or not) as follows:78

a. Meter locations required to reflect the interconnection with the transmission system for ISDs;
b. Meters required to recognize a phased developments involving multiple generating units;
c. Meters located to minimize metering costs; and
d. Meters located to avoid access problems when reading meters.

96. TransCanada’s conclusion was that “(t)he decision to have one revenue meter for one MPID is a function of matters largely unrelated to the fact that these generating units are connected to one bus. For this reason alone, the determination of whether a group of generating units are totalized into one MPID or not is discriminatory and unjust.”79

97. Finally, TransCanada stated that the AESO’s position that it will not allow meter arrangements to be altered “after the fact” is both arbitrary and unfair, especially given the history of how various meters came to be installed.80

98. Given the choice between calculating line loss factors using ILF by unit and ILF by plant, Capital Power expressed a strong preference for the latter. To a very significant extent, Capital Power shared the same concerns, and raised the same objections, with respect the AESO’s ILF by unit methodology as those raised in evidence and argument by other opponents of this methodology.

99. According to Capital Power, the Commission should reject the AESO’s proposal to calculate line loss factors at a unique MPID for each generating unit. Instead, the Commission should define location as the plant or system bus for purposes of calculating increment-based line loss factors. In Capital Power’s view, this would bring the resulting line loss factors in closer alignment with the principle of cost causation and would mitigate the discriminatory treatment against, and competitive harm suffered by, co-located generating units relative to stand-alone (i.e., independently connected) generating units under the AESO’s proposed methodology.

40. In fact, it is the definition of location as the MPID that is inconsistent with the principles of cost causation. It leads to undue benefit for independently connected generating units while causing undue harm to those that are co-located.81

…

5. The ILF by MPID Methodology involves differential treatment of similarly situated generating units without cause or justification. Specifically, the AESO’s proposed ILF by MPID Methodology produces raw loss factors that consistently and significantly overcollect the aggregate cost of industry line losses. For many generating units, this over-collection is disproportionate relative to their location and contribution to average systems losses. This over-collection is exacerbated for generators that are co-located – as

78 Exhibit 790-X0419, TransCanada argument, July 31, 2015, page 38, paragraph 114.
79 Ibid., pages 37-38, paragraph 112.
80 Ibid., page 39, paragraph 117.
81 Exhibit 790-X0435, Capital Power reply argument, August 28, 2015, page 13, paragraph 40.
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Compared to generators that are not co-located – due to the application of a common shift factor. 82

... 

52. ...the application of the ILF by MPID Methodology at the raw loss factor step results in over-collection of aggregate system losses. The subsequent application of a shift factor – to remedy the over-collection – results in unjust discrimination among generators. However, defining “location” as the plant/bus mitigates both problems – over-collection and discrimination. 83

100. Capital Power sought to frame its objections to the ILF by MPID methodology in terms similar to those which the Commission used in Decision 2014-110 to describe the fundamental flaw in how the current Line Loss Rule determines line loss factors:

51. The failings of the ILF by MPID Methodology raise the same basic concerns [as those identified by the Commission with respect to the current MLF/2 methodology]. The proposed methodology – and the mechanism to reconcile differences in total losses and those collected – "socialize" the excessive and asymmetric over-collection from a specific class of generating units. Specifically, independently connected generating units are attributed lower losses than they would be otherwise by virtue of the over-collection of losses from units that are co-located. 84

101. Unlike TransCanada, Capital Power did not address in its written argument either the AESO’s proposed exception list (including the principles upon which it is based) or how and why MPIDs may have been chosen in the past. Instead, Capital Power simply noted that if “the Commission finds that “location” is to be defined at the plant or system bus” as Capital Power has requested, then “an Exceptions List would be unnecessary much as it is today.” 85 However, it also went a step further than any other party opposed to defining location at the MPID by expressly requesting that, should the Commission approve the MPID as the location for determining line loss factors, it at the same direct the AESO to:

a) Allow market participants a “one-time” opportunity to relocate their meters (i.e., move the MPID) to a location that complies with the AESO’s metering standards without compromising or prejudicing operations at multi-unit facilities at a system bus.

b) Allow market participants to aggregate their own units at the relevant system bus such that a single loss factor is applicable to each unit connected to the Alberta Interconnected Electric System at that bus.

102. Capital Power provided no specific reason why such an order should be issued, nor did it reference any arguments made by other parties that might support such an order.

103. In its written argument, TransAlta raised an entirely different concern about the ILF by unit methodology from those mentioned by other parties. It pointed out that the more favourable line loss factors assigned by the ILF by unit methodology to larger generating units relative to smaller generating units at the same physical location will affect capital investment/output

82 Exhibit 790-X0412, Capital Power argument, July 31, 2015, page 3, paragraph 5.
83 Ibid., page 16, paragraph 52.
84 Exhibit 790-X0435, Capital Power reply argument, August 28, 2015, page 16, paragraph 51.
85 Ibid., page 20, paragraph 72.
Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Phase 2, Module B

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expansion strategies of owner-operators of existing generating units. In particular, where owner-operators of existing generating units are planning to increase their total output at a given location, there will be an incentive for them to do so (where possible) by directly adding to or expanding the physical capacity of their existing unit(s) rather than constructing new units immediately adjacent to those existing units. According to TransAlta:

112. The ILF method will also introduce intergenerational inequity. The bias of the ILF methodology in favour of larger generating units would have encouraged generation developers to structure developments as expansions under an existing MPID instead of as new developments. For example, it is likely that Summerview 2 would have been structured as an expansion of Summerview 1 instead of a new generating unit. Similarly, Ardenville and Blue Trail would likely have been amalgamated to create a larger wind aggregated generating facility to maximize the generating unit size bias received under an ILF method.

104. TransAlta did not elaborate on the economic efficiency implications of this potential line loss rule-induced bias in favour of same-unit expansion versus growth by new unit construction once a decision to increase total output at a single location has been made.

105. ENMAX rejects all versions of the ILF methodology, preferring instead its own superposition proposal. This notwithstanding, ENMAX did provide its own views on the merits of selecting location at the system bus versus the MPID under an ILF methodology as follows:

123. The AESO states that it chose the MPID as the location at which to calculate loss factors because the use of the system bus would limit its ability to appropriately reflect the potentially different impacts on system losses from different types of generation. EEC submits, however, that the use of the system bus is necessary but not limiting.

124. With respect to the “necessary” part, the physics is clear that generators connected at locations that are separated by zero-impedance connections cannot have different effects on system losses in real time. Their currents, upon entering a transmission line, are “merged” in accordance with Kirchoff’s Current Law and become indistinguishable. For example, in Figure 1 of the response to AESO-TCE-2015JAN08-006, Generators 1 and 2 are connected to System Bus X in such a way that the transmission system has no way of physically distinguishing their loss impacts. Their RLFs must therefore be the same.

125. Having identical RLFs does not, however, limit the ability to reflect the different operating characteristics of the units connected at a system bus because their weighting factors can be different. As a rudimentary example $G_1$ and $G_2$, two generators located at the same bus, could have their annual loss factors calculated as follows (using a simplified four-base-case “year”). The units will have annual loss factors of 4.40% and 3.35%, respectively.

<table>
<thead>
<tr>
<th></th>
<th>Spring RLF</th>
<th>Summer RLF</th>
<th>Fall RLF</th>
<th>Winter RLF</th>
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<tr>
<td>$G_1$</td>
<td>10%</td>
<td>30%</td>
<td>10%</td>
<td>50%</td>
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<tr>
<td>$G_1$</td>
<td>25%</td>
<td>20%</td>
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<td>30%</td>
</tr>
</tbody>
</table>

126. There are efficiency and reliability reasons for assigning identical loss factors to the units connected at the same system bus. Consider, for example, a situation in which there are three identical gas turbines, all owned by the same market participant, connected at

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87 Exhibit 790-X0416, TransAlta argument 790 Phase 2 Module B Final, July 31, 2015, page 32, paragraph 112.
the same system bus. In real time, one unit is an exact substitute for either of the other two from the line-loss perspective. As such, the market participant should have the ability to make choices about the offering and running of those units based on machine hours, maintenance scheduling, and other considerations, without having to worry about purely artificial differences between loss factors. Other situations—for example, where there are multiple owners of units connected at the same bus—may call for different treatment. The fact that the AESO is currently prepared to allow different loss factors at the same physical location suggests that market participants should be given a choice as to how the loss factors at a system bus are treated, subject to appropriate rules.

4.4 The AESO’s proposed loss factor rule

106. The AESO proposes to calculate loss factors for each system access service (Section 2(1)) and that each system access service under Rate STS provides service to only one generating unit or aggregated generating facility (Section 7(2)).

2(1) The ISO must establish and maintain a final loss factor for each calendar year, subject to subsection 2(3) below, for each system access service that the ISO provides under:

(a) Rate STS of the ISO tariff, Supply Transmission Service;
(b) Rate DOS of the ISO tariff, Demand Opportunity Service;
(c) Rate XOS of the ISO tariff, Export Opportunity Service; or
(d) Rate IOS of the ISO tariff, Import Opportunity Service.

7(1) The ISO must calculate a loss factor at the measurement point for the point of supply or point of delivery applicable to each system access service provided under Rate STS or Rate DOS.

(2) The ISO must ensure that a system access service under Rate STS provides service to only one generating unit or aggregated generating facility, unless that system access service is included by the ISO on the List of Measurement Point Exceptions for Loss Factor Calculations as published by the ISO on the AESO website and as amended from time to time by the ISO on notice to market participants.

(3) The ISO must include a system access service on the List of Measurement Point Exceptions for Loss Factor Calculations when two or more generating units or aggregated generating facilities:

(a) are connected with load on an electric system that is not part of the transmission system for which losses are being determined, including within an industrial system designated by the Commission or on an electric distribution system;

(b) are operationally interdependent such that one generating unit or aggregated generating facility cannot operate without the other also operating under normal operating conditions, including combined cycle facilities;

(c) are in service and connected to the transmission system through a single system access service as of December 31, 2015; or

Exhibit X0345, AESO proposed line loss rule, June 19, 2015.
Complaints regarding the ISO Transmission Loss Factor Rule

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(d) are planned to be connected to the transmission system through a single system access service and the Commission has issued a permit and licence for the connection project for the generating facilities as of December 31, 2015.

107. The AESO has proposed an ILF by unit line loss methodology subject to an exception list. For each generating facility that is not on the exception list, a single line loss factor will be calculated for each generating unit comprising that generating facility. The AESO proposes to use the expected output of each generating unit as the size of the increment for that generating unit. As noted in Section 7(3) of the proposed line loss rule, the AESO proposes several exceptions to using the generating unit as the size of the increment. These exceptions are listed in Exhibits 790-X0178 and 790-X0245. For each exception, the AESO proposes to aggregate the expected output of two or more generating units in determining the size of the increment to be used in calculating the single loss factor for the generating facility. The exception list has been filed in this proceeding for reference, but the AESO does not intend to file the exception list as part of the proposed line loss rule.

4.5 Commission findings regarding location

108. The Commission has had occasion many times at different stages of this proceeding to examine and carefully consider the provisions of the Transmission Regulation applicable to line losses, as well as the public interest goals and objectives of the Electric Utilities Act. A key issue to be determined by the Commission in the present proceeding is the meaning of the term ‘location’ in the Transmission Regulation. A summary of the modern principles of statutory interpretation, as enunciated and upheld by the courts and elaborated upon by various authorities, that have guided the Commission – as much in the past as in the instant proceeding – is provided below. At paragraphs 42 and 43 of Decision 2014-110, for example, the Commission took note of the following:

42. In **Balancing Pool v TransAlta Corporation**, 2013 ABCA 409, the Alberta Court of Appeal reiterated general principles of statutory interpretation. The case there under appeal involved interpretation of the 2003 Electric Utilities Act, the legislation under consideration in this proceeding and interpretation of a different regulation made under it. The following passages at paragraphs 37, 19 and 23 are applicable to this proceeding.

Coutes have long adopted Driedger’s modern principle as the method to follow for statutory interpretation: “...the words of an Act are to be read in their entire context, in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament”: E.A Driedger, Construction of Statutes, 2nd Ed (Butterworths: Toronto, 1983) at 87; see for example: **Re Rizzo and Rizzo Shoes Ltd**, 1 [1998] SCR 27, 154 DLR (4th) 193; **Bell ExpressVu Limited Partnership v Rex**, 2002 SCC 42, [2002] 2 SCR 559; **ATCO Gas & Pipelines Ltd v Alberta (Energy and Utilities Board)**, 2006 SCC 4, 263 DLR (4th)193 at para 37.

In **ATCO Gas v AEUB**, 2006 SCC 4, [2006] 1 SCR 140 (ATCO Gas), Bastarache J. approached the interpretation of the relevant statutory provisions at issue by looking first at the grammatical and ordinary meaning of those provisions, then at the entire statutory context and the legislative intent, including the applicability of the doctrine of necessary implication. We adopt a similar framework here – at para 19.

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90 Exhibit X0178, AESO list of measurement point exceptions, April 9, 2015, and exhibit X0232, AESO response to AUC information request regarding principles to cover the exception list, April 19, 2015.

91 Exhibit 790-X0409, AESO argument, July 31, 2015, page 5, paragraph 17.
The provisions in s 2 of the *Regulation* are part of a larger statutory scheme which must also be considered. As the Supreme Court has recently stated, “the ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme”: *ATCO Gas* at para 49. In this regard, the Supreme Court cited with approval the following comment by Pierre-Andre Côté:

> As the product of a rational and logical legislature, the statute is considered to form a system. Every component contributes to the meaning as a whole, and the whole gives meaning to its parts: “each legal provision should be considered in relation to other provisions, as part of a whole”... (P. A. Cote, The Interpretation of Legislation in Canada (3rd ed 2000, at page 308)) – at para 23

43. As indicated in *Sullivan on the Construction of Statutes*, generally the rules governing the meaning of statutory texts and the types of analysis relied upon by interpreters to determine legislative intent apply equally to regulations. Regulations too must be read in the context of their enabling statute, having regard to the language and purpose of the act in general and more particularly the language and purpose of the relevant enabling provisions. This is consistent with Section 13 of the *Interpretation Act* which provides that interpretation provisions in an enactment apply to regulations made under an enactment.

109. In Decision 790-D02-2015, at paragraphs 67-68, the Commission further elaborated upon its approach to statutory interpretation as follows:

67. Also, in *Sullivan on the Construction of Statutes*, Fifth Edition, at page 359:

> [W]hen words are read in their immediate context, the reader forms an initial impression of their meaning. ... But any impression based on immediate context must be supplemented by considering the rest of the Act, including the other provisions of the Act and its various components.

68. Further, at page 364, the author notes:

> When analyzing the scheme of the Act, the court tries to discover how the provision or parts of the Act work together to give effect to a plausible and coherent plan. It then considers how the provision to be interpreted can be understood in terms of that plan. ... The fundamental presumption in scheme analysis is being able to grasp and explain the basic structure on which the Act is built and how the various parts and provisions were meant to function within this structure to achieve the desired goal, or more often, the desired mix of goals.

110. The purposes of the *Electric Utilities Act* are set out in full in section 5 of that statute:

**Purposes of the Act**

The purposes of this Act are

(a) to provide an efficient Alberta electric industry structure including independent, separate corporations to carry out the responsibilities of the Independent System Operator and the Balancing Pool, and to set out the powers and duties of those corporations;
(b) to provide for a competitive power pool so that an efficient market for electricity based on fair and open competition can develop, where all persons wishing to exchange electric energy through the power pool may do so on non-discriminatory terms and may make financial arrangements to manage financial risk associated with the pool price;

(c) to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant;

(d) to continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces;

(e) to enable customers to choose from a range of services in the Alberta electric industry, including a flow-through of pool price and other options developed by a competitive market, and to receive satisfactory service;

(f) to continue the sharing, among all customers of electricity in Alberta, of the benefits and costs associated with the Balancing Pool;

(g) to continue the framework established for power purchase arrangements;

... to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.

111. The Commission, in Decision 2014-110, focused a considerable amount of its attention on the objectives of the Electric Utilities Act and how the Transmission Regulation must be interpreted with a view to achieving those objectives. Among its principal determinations in that regard were the following:

58. There is no inconsistency or tension between or among the requirements for fairness, openness and efficiency that needs to be balanced in order to achieve the public interest. The public interest is expressed in the objective – an efficient market for electricity based on fair and open competition. The ISO’s role is to create the conditions under which an efficient market for electricity can develop within the parameters of the market model specified in the 2003 Electric Utilities Act and the 2004 Transmission Regulation.

...
63. The fact that the loss factor for each generating unit must be determined and maintained at each location anticipates that loss factors may be different at each location and the requirement that the ISO must determine a loss factor with respect to a generating unit that a person proposes to construct at a “place in Alberta where a generating unit is not located” means that locational signals for investment will be created by a line loss rule that complies with the 2004 Transmission Regulation and the 2003 Electric Utilities Act. … The review panel is of the view that all that is necessary is that the line loss rule comply with the words of the 2004 Transmission Regulation and the 2003 Electric Utilities Act. Whatever signals result, whether for investment or for dispatch, from such a rule will be what the legislators intended and will be efficient within the market structure set out in the legislation.

…

79. The review panel does not consider the 2004 Transmission Regulation to be so prescriptive as to limit the interpretation of location on the transmission system in a way that would preclude consideration of more than one approach to determining location on the transmission system for the purposes of complying with the requirements of the legislative framework.

112. In Decision 2012-104, the Commission discussed the economic principle of cost causation and its relationship to the statutory goals of economic efficiency and non-discrimination in rate-making as follows:

64. A principle that tests whether a rate is unjustly discriminatory when designing rates is that of cost causation. This principle states that those classes of customers that cause certain costs to be different from the costs of serving other customers may expect to pay a different rate proportional in the amount of their costs. Those customers, however, who do not cause any difference in costs to the utility, may therefore not be charged discriminatory prices. In other words, those who are causing the same types of costs should not be discriminated against in the types of rates they are charged.

65. The AESO, for example, when seeking approval of its tariffs uses this principle when designing its tariffs. It did so in its 2005/2006 general tariff application, its 2007 general tariff application, and its 2010 tariff application. To pick one application, for example, the AESO in its 2007 general tariff application “ultimately reiterated that cost causation was the most critical element in satisfying the five Bonbright principles that it endorsed.”

66. The Board, in that proceeding, went on to state that three primary Bonbright principles that should be given the most weight in evaluating a rate design were the “[r]ecovery of revenue requirement,” the “[p]rovision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service,” and “[f]airness, objectivity, and equity that avoids undue discrimination and minimizes intercustomer subsidies.” The Board then concluded that “cost causation therefore remains the primary consideration when evaluating a rate design proposal.”

67. This conclusion was supported by the Board’s observation that “[i]f the cost causation principle is satisfied by a rate design, then proper price signals will be sent to customers, and these price signals will act as an incentive for customers to use the system efficiently.” In fact, the Board observed that it need not “explicitly recognize efficiency” for “efficient system use is a by-product of a rate design based on a proper cost allocation.”
137. As the Commission said above, when it comes to losses, efficient allocations are required to give efficient signals. Efficient signals are required to site locations of efficient generation. Efficient generation reduces marginal costs to generators and ultimately marginal prices to consumers. Efficient signals also have the added benefit of signaling generation investment that may ultimately reduce the overall cost of the system, thereby complying with the objectives of the Electric Utilities Act and the Transmission Regulation.

113. As noted above, there are two competing positions in this proceeding as to how location should be defined within the context of an ILF approach to calculating line loss factors. One group of parties focuses primarily on Section 19(1)(a) of the Transmission Regulation in support of the proposition that location should be generating unit specific (albeit subject to certain exceptions). Section 19(1)(a) of the 2004 Transmission Regulation provides that the “ISO must make rules to reasonably recover the cost of transmission line losses on the interconnected transmission system by establishing and maintaining loss factors for each generating unit based on their respective locations and their respective contributions, if at all, to transmission line losses”. The second group of parties relies on sections 19(2)(d) and 19(2)(e) to support their view that when two or more generating units are located in close physical proximity to each other and interconnect at one location (i.e., the plant or system bus) at which electrical power is collected prior to being injected into the transmission system, that point of interconnection must correspond to the point at which a single line loss factor is to be calculated for that entire group of generating units. Section 19(2)(d) provides that “(i)n accordance with the rules made under subsection (1), the ISO must determine loss factors having regard to the…” requirement that “the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load,” while section 19(2)(e) states, in relevant part, that “the loss factor must be one number at each location.” 92

114. At first glance, these provisions of the Transmission Regulation, when read in isolation and given their plain and ordinary meaning, appear to be in conflict with one another. While it is clear that the legislature envisioned instances in which more than a single generating unit could be built and operated at the same physical location, it is not immediately apparent from the Transmission Regulation whether it was the intention of the legislature that each generating unit, including co-located generating units, should be assigned a separate line loss factor or whether it was intended that a single line loss factor be calculated for each group of co-located generating units. As was argued by TransCanada, Section 19(2)(e), especially given the words “or group of generating units” in Section 19(2)(d), could serve no possible purpose unless it was the intention of the legislature that the output of two or more generating units at the same physical location could be aggregated so as to produce a single line loss factor for the entire group of generating units.

115. In the Commission’s view, however, when these apparently inconsistent provisions of the Transmission Regulation are considered “in relation to other provisions, as part of a whole” and are examined in light of the overarching scheme and purpose of the governing legislation so as to give full and coherent expression to the intent of the legislature, a different conclusion emerges. In particular, when the definition of “generating unit” in the Electric Utilities Act is

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92 Transmission Regulation, sections 31(2)(c) and (d).
read purposefully so as to preserve “the harmony, coherence and consistency of the legislative scheme,” it follows that where two or more co-located generating units are owned or controlled, managed, and operated as a single generation facility, whether constituting all, or only a part, of a single business enterprise in competition against other similar business enterprises, their output may be aggregated for purposes of determining a single line loss factor for those generating units.

116. The Commission accordingly finds that the definition of location upon which the AESO’s proposed ILF by unit loss factor methodology is premised, namely, the MPID, can be made compliant with the Transmission Regulation and Electric Utilities Act. There remain certain other deficiencies in the AESO’s proposed approach that, if not revised, would preclude a Commission finding that the AESO’s proposed methodology complies with the governing legislation and regulations.

117. In the AESO’s view, there is no legislative or regulatory requirement for each generating unit to be assigned a unique MPID for purposes of calculating line loss factors. The Commission agrees. However, the AESO has proposed a line loss rule that is inconsistent in terms of how it is applied. Proposed departures from the rule have been consolidated into a list of exceptions to how the rule would be implemented. Many generating units in Alberta would be assigned a unique MPID. Many would not.

118. The AESO’s proposed exception list includes all of the following:93

A system access service at a measurement point listed below is excepted from the requirement that a system access service under Rate STS provide service to only one generating unit or aggregated generating facility, as would otherwise be required under subsection 7(2) of section 501.10 of the ISO rules, Transmission Loss Factor Methodology and Requirements.

(a) An industrial system that has been designated as such by the Commission with a single system access service under Rate STS for the industrial system.

(b) CMH1 – City of Medicine Hat Generation

(c) FNG1 – Fort Nelson Generation (British Columbia)

(d) Any generating unit or aggregated generating facility connected to an electric distribution system that results in electricity flowing into the transmission system at a point of delivery.

(e) A hydro facility with multiple generating units that is subject to a single power purchase arrangement, specifically:

BIG – Bighorn Hydro
BRA – Brazeau Hydro
CAS – Cascade Hydro
GHO – Ghost Hydro
HSH – Horseshoe Hydro
KAN – Kananaskis Hydro
RUN – Rundle Hydro

93 Exhibit 790-X0289, AESO list of measurement point exceptions, May 19, 2015.
SPR – Spray Hydro

(f) A combined cycle facility with a single system access service under Rate STS for all generating units at the facility, unless otherwise agreed to by the ISO in writing, including:

EC01 – Cavalier
EGC1 – Shepard
NX01 – Nexen Inc #1

(g) A facility that has a single system access service under Rate STS for two or more generating units at the facility when, as of December 31, 2015, the facility was in service or the Commission had issued a permit and licence for the connection project for the facility, including:

AFG1TX – Athabasca
ANC1 – Alberta Newsprint
DRW1 – Drywood
NPC1 – Northstone Elmworth
OMRH – Oldman River
SHHG – Shell Caroline
TAY1 – Taylor Hydro (including wind generators)
TC01 – Carseland Cogeneration
TC02 – Redwater Cogeneration

119. The Commission has determined that there is no need for an exception list such as that proposed by the AESO. All of the exceptions identified by the AESO can be captured in a single line loss rule – such as that proposed by the AESO – modified as follows. Both prior to – and once each calendar year following – the implementation of a revised line loss rule, all generators may configure (i.e., aggregate or disaggregate), at one or more MPIDs, all generating units that they own or control, manage, and operate as a single business enterprise or undertaking at a single physical location. For example, prior to the implementation of the revised line loss rule, a generator that owns or controls, manages and operates multiple co-located generating units at two or more MPIDs as part of a single generating facility at a single physical location would have the option to aggregate some or all of its generating units at fewer MPIDs in the same physical location. This would not be a one-time option. The following year, the same generator would be allowed to reverse its decision, or alter it in any way, by disaggregating or re-aggregating at one or more MPIDs in the same physical location. This annual option to aggregate, disaggregate and/or re-aggregate at one or more MPIDs in the same physical location will apply equally to existing and future generators (i.e., new entrants). Any generator electing to aggregate more than one generating unit at a single MPID will forgo the benefit of the seven price quantity pairs allocated to the generating unit or units associated with each MPID no longer required. The opposite will apply to generators electing to re-assign generating units previously connected to a single MPID to two or more MPIDs. Any co-located generating unit or units sold to an unrelated third party will be assigned to one or more new MPIDs (at the same physical location) as determined by the purchaser. The Commission notes that all of these options would be neutral both with respect to generation technology and type of fuel used. The direct costs of implementing these changes, including the costs of installing (or, if applicable, removing) meters and of entering into or terminating STS contracts associated with each MPID will be borne by the generator making the change.
120. The Commission’s reasons for modifying the AESO’s proposed line loss rule to allow for these options are based on the need to avoid unjust discrimination and undue preference or, what in substance amounts to the same thing, the need to avoid causing undue harm to the competitive process by unjustly or unfairly favouring or disadvantaging some market participants relative to others by the manner in which the new line loss rule is implemented. In reaching the conclusions in this decision, the Commission has not considered how the definition of location should apply to units subject to a power purchase arrangement. The Commission expects the AESO to address this issue prior to, or at the time of, its compliance filing.

121. One of the strengths of the AESO’s proposed methodology is that it expressly recognizes, as did the Commission in Decision 2014-110, that the governing legislation and regulations are not so restrictive as to require a single definition of location in all circumstances. The weakness in the AESO’s methodology is that it does not fully capture all circumstances in which one definition of location (the plant bus) should apply instead of the other (the metering point for an individual generating unit). That is, the AESO’s methodology fails to recognize all situations in which the aggregation of output for co-located generating units serves the efficiency and fairness (i.e., non-discrimination) objectives of the Electric Utilities Act.

122. Economic theory predicts that in a competitive market profit-maximization will drive improvements in economic efficiency. A generator planning to expand capacity at a given physical location will attempt to do so in an economically efficient manner. This may mean (1) replacing an older and smaller generating unit with an entirely new and much larger unit (perhaps even one employing new technology and/or relying on a different type of fuel because of changes in the relative price of alternative energy sources or because of changes in environmental regulation); (2) physically augmenting the productive capacity of an existing generating unit (where this is technologically feasible); or (3) building immediately alongside the existing unit a new generating unit capable of producing the desired incremental increase in output.\footnote{A fourth option would be to expand output at another physical location to meet the anticipated increase in demand. This latter option, however, automatically results in a different location for the new generation and, thus, need not be considered further here.} Whatever option is chosen by the generator to expand its output at a given physical location, the AESO’s selection of a loss factor methodology should not interfere with how that generator chooses to increase output. In particular, the AESO’s choice of a line loss rule, including the location at which line loss factors are to be calculated, should not create a financial bias (unrelated to any considerations of economic efficiency) in favour of or against any particular approach to expanding output at any given physical location. Yet, as TransAlta has argued, this is precisely what the AESO’s proposed ILF by unit methodology would do. Expanding output by building one or more new co-located units rather than by replacing or refurbishing an existing unit (where the full increment in additional capacity at that location will be operated in a coordinated manner by a single owner-operator) will result in that owner-operator being assessed higher line loss charges for its aggregate output. This anomalous result violates considerations of both economic efficiency and fairness.

123. The AESO, and other parties supporting its proposed methodology and definition of location, defend this outcome based on the Commission’s finding in Decision 2014-110 that, in order to comply with sections 19(1)(a) and 19(2)(d) of the Transmission Regulation, any changed line loss rule would have to calculate a generating unit’s contribution to total transmission line losses over the full range of that generating unit’s output. This Commission direction, however, is simply an expression of the principle of cost causation that underlies the...
efficiency objectives of the *Electric Utilities Act* and the fairness or non-discrimination criterion that is central to tariff design in regulated industries. In this case, the legislation requires that generators bear the cost of line losses that can reasonably be attributed to them. That, in turn, is a function of their level of output and the location from which they supply electrical power to the transmission system.

124. The Commission finds, based on the record of this proceeding, that generators that own or control, manage and operate more than one generating unit at a given physical location typically treat those units as part of a single economic enterprise or undertaking and not as independent, standalone businesses. The proposed AESO rule would affect the freedom of generators to operate in this way because it would require that a different loss factor be calculated for each commonly-owned and controlled generating unit at a single geographic location, thereby unduly and without justification influencing the offer strategies of generators. In the Commission’s view, the calculated line loss factors of multi-unit generators should be determined on the basis of the generators’ investment and economic operating decisions, rather than on the basis of regulatory fiat. This means that generators should be permitted to choose whether to aggregate or disaggregate based on competitive market conditions. This is the economic rationale for interpreting location in Section 19(2)(d) of the *Transmission Regulation*, as applying to either a generating unit or a group of generating units, as decided by the owner-operator. It is also a more faithful expression of legislative intent when one of the principal purposes of the *Electric Utilities Act* is to create efficient markets.

125. The Commission notes in this regard that even parties as opposite in interest in this proceeding as ATCO and ENMAX tacitly, if not expressly, agreed that (the exception list aside) ownership and control of co-located generating units might well provide sufficient economic justification for allowing aggregation of the output of such units at a single MPID. What concerned ATCO most, for example, was “indiscriminately grouping units,” not grouping units based on ownership or on some other justifiable basis. ENMAX went even further in suggesting that there was no reason to deny owners of co-located units operated as one undertaking the ability to aggregate. “Other situations—for example, where there are *multiple owners* of units connected at the same bus—may call for different treatment. The fact that the AESO is currently prepared to allow different loss factors at the same physical location suggests that market participants should be given a choice as to how the loss factors at a system bus are treated, subject to appropriate rules.”

95 Unstated, but evident enough in these propositions, is the cost causation principle that unrelated parties should not be allowed to free-ride on the cost savings attributable to other competitors.

126. It is important to observe that the Commission’s decision to allow all existing generators that own or control, manage and operate co-located generating units the ability to aggregate (or, if desired, disaggregate) the output of those units at one or more MPIs prior to the implementation of an ILF by unit loss factor methodology is based on a somewhat different rationale than the decision to provide generators the same option on an annual basis after the revised line loss rule comes into effect. The reason for granting the initial option is that it is

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95 Exhibit 790-X0069, ENMAX evidence, March 12, 2015, page 46, paragraph 126.
96 Other parties conceding or at least appearing to acknowledge that aggregation at a single MPID may be justified in the case of co-located generating units owned or controlled, managed and operated as a single economic undertaking by a single corporate entity include Medicine Hat (see exhibit 790-X0403 at paragraphs 93-94, and 96). Medicine Hat, for example, intimates that co-located units that are operated “as an amalgamated or highly integrated whole” might justifiably be aggregated at a single MPID.
consistent with the overriding scheme and purpose of the governing legislation and regulations. Granting existing owner-operators of multiple co-located generating units the initial option to reconfigure output at one or more MPIDs also addresses the important concern raised by TransCanada. That is, the history of why and where meters were installed and MPIDs were selected is largely, if not entirely, unrelated to how line loss factors have been calculated and assigned to date. In addition, the original assignment of MPIDs was made prior to the Commission’s finding that the current Line Loss Rule is unlawful. This is important because there will be potentially different competitive market consequences arising from the existing configuration of MPIDs under the changed line loss rule relative to the current rule. Thus, the option to reconfigure MPIDs prior to implementing the changed line loss rule should be seen as providing generators that may be less well-off under the changed rule with the opportunity to make themselves no worse off (on a going forward basis) than they would have been had they been able to make this choice from the outset. Stated differently, going forward, generators will be allowed to capture or retain no more than that which they are entitled to under a compliant methodology rather than something less because of how their generation happened to be configured under different methodologies.

127. Seen in this light, it should be clear that allowing generators an annual option to reconfigure (i.e., aggregate, disaggregate or re-aggregate) output at one or more MPIDs is not a prescription for gaming. It will not allow any generator to secure for itself a lower line loss factor than what the revised line loss rule would otherwise provide under the most favourable of output configurations. Generators cannot make themselves any better off in the zero-sum world of line loss allocations than the best possible allocation to which they would already be entitled under the changed line loss rule.

128. This raises two further important considerations. First, should generators choose not to aggregate at a single MPID the output of all generating units that they own, manage and operate at a single physical location, it would have to be the case that other competitive considerations were of greater value and importance to them. In either eventuality, the Commission is of the view that market participants should be free to make these determinations without undue regulatory interference based on their own competitive circumstances and market strategies. And second, notwithstanding the ability of eligible generators to annually reconfigure the location at which line loss factors would be calculated for the output they produce, the Commission’s expectation is that this option is unlikely to be exercised very frequently once each generator has established its preferred initial MPID configuration under the revised rule. Should this expectation prove to be incorrect, and the AESO begin to experience difficulties, including materially higher costs, in administering its methodology because of frequent changes in the locations at which loss factors are to be determined, not to mention the competitive impacts of greater volatility in the resulting loss factors themselves, the Commission is prepared to reconsider this aspect of its decision following implementation of the revised rule.

129. In summary, the Commission’s decision to use MPID as the basis for determining location, as qualified by the options discussed above, is not only consistent with the meaning of “location” in the Transmission Regulation when considered in light of the aims and objectives of the Electric Utilities Act, but has several other advantages associated with it:

- It eliminates the need for the AESO’s proposed exception list.
- It places all existing and future market participants on a comparable footing with respect to how their contribution to and impact on line losses is calculated upon the introduction of a revised line loss rule.

- It recognizes that generators typically view planned or potential future expansion of capacity at a single physical location simply as an organic increase in the overall generation capacity of a single economic enterprise they own or control, manage and operate at that location, and not as the creation of a new and unrelated business enterprise to be run separately from their existing capacity at that location. This reasoning applies regardless of the number of existing generating units currently comprising the generating facility in question. In explicitly recognizing this, the Commission’s decision eliminates what would otherwise amount to an unjustified bias against expansion of existing capacity at a given location by way of new unit construction.

- It is technology and fuel choice neutral and allows market participants the freedom to construct and/or operate, that specific configuration and combination of generating facilities at one physical location that best advances their legitimate competitive interests.

- It allows market participants the ability to contract for as many or as few MPIDs in one location as they wish. This will provide them with greater flexibility in designing offer strategies to the power pool associated with access to several sets of price/quantity pairs, should they perceive this to be of competitive benefit to them.

- It does not allow unrelated market participants to share an MPID previously assigned to one or more generating units owned, managed and operated by a different generator.

- It simplifies the AESO’s loss factor calculation process and provides greater transparency and clarity for market participants: one MPID means one set of price/quantity pairs and a single line loss factor for all generating units associated with that MPID.

5 SWINGBUS AND BASE CASES TO IMPLEMENT ILF ANALYSIS

130. The principal advantage of an incremental line loss factor methodology is that it takes each generating facility at each location on the AIES and calculates its full contribution to line losses by comparing system-wide line losses with and without the output of each generating facility. This ‘but-for’ analysis requires that the system be rebalanced when the output of each generating facility is removed from the model. ‘Swingbus’ is a generic term for whichever element of the system is adjusted such that the system rebalances after the removal of the output of the generating facility being assessed.

131. There are only two possible ways to rebalance the system when doing the ‘but-for’ analysis, that is, when removing a generating facility from the system. The AESO must either (1) scale down load or (2) scale up generation to replace the output attributable to the now removed generating facility. In the case of scaling up generation, the AESO has two main options to identify which generating facilities are to provide replacement output for that removed from the system: (a) rely on the GSO or (b) rely on the energy market merit order.

132. In its proposed line loss rule, as in the current rule, the AESO models the operation of the AIES over the entire year by using 12 base cases to represent the typical high, medium and low
periods in each of the four seasons. Each of the 12 base cases represents the anticipated output of all generating facilities used to serve typical load, including line losses (i.e. the system balances) during the instant in time each base case is measured. For each base case, the AESO calculates a raw incremental loss factor for each generating facility, such that there are 12 raw incremental loss factors per year for each generating facility. It is during the calculation of these raw incremental loss factors for each generating facility that the AESO must identify which element of the system will be used as the swingbus to rebalance the system, as discussed in greater detail below. The AESO then shifts the raw loss factors in each base case such that the total system losses for each base case are recovered, leaving the AESO with 12 normalized loss factors for each generating facility. The AESO then takes a weighted average of the 12 normalized seasonal loss factors to obtain a single annual loss factor for each generating facility, and then normalizes on an annual basis. These annual loss factors are then adjusted to fit within the collars set out in the Transmission Regulation to produce a single, final loss factor for each generating facility.

5.1 Using load scaling to rebalance the system

133. When calculating the 12 raw incremental loss factors for each generating facility, the AESO’s proposed line loss rule uses load scaling (all load is scaled down proportionally) to rebalance the system.  

134. Among those parties favouring the ILF methodology over the superposition methodology for the purpose of calculating raw loss factors, there was broad consensus that load scaling was preferable to GSO re-dispatch as a means of rebalancing the system once a generating facility is removed. Only a few parties, however, offered any specific reasons in support of load scaling. Other than noting that in Decision 2014-110 “the Commission found that the use of distributed load as the balancing swing bus was “not inconsistent” with the provisions of the Transmission Regulation”, 98 most simply argued that GSO dispatch was not feasible. The AESO and Milner, however, did provide standalone reasons for relying on load scaling to rebalance the system independent of their objections to any alternative approach.

135. According to the AESO: 99

41. Impact relative to distributed load is assessed by reducing all loads proportionately to balance the removal of a generating unit when determining losses before the generating unit produces its power. Reducing all loads proportionately reflects the impacts of generation on flows throughout the transmission system and removes any subjectivity in the selection of loads to reduce or lines to adjust following removal of a generating unit.

136. Milner took a different perspective. It argued that load scaling is the preferred rebalancing alternative because it avoids the problem of re-pricing system output when generation is re-dispatched. 100

114. The choice of a distributed swing bus is appropriate because it is aligned with the legislated requirement that load not pay directly for losses, i.e. load is assumed to pay at the system price, with the loss factor for load equal to zero. This means that the “load price is the system price and all other prices are "keyed" to this system price: a generator receives (a) the system price minus (b) the system price multiplied by its loss factor.

97 Exhibit 790-X0345, AESO proposed line loss rule, June 19, 2015, at section 8.
98 Exhibit 790-X0403, Medicine Hat argument, July 31, 2015, page 37, paragraph 134.
99 Exhibit 790-X0409, AESO argument, July 31, 2015, page 9, paragraph 41.
100 Exhibit 790-X0417, Milner argument, July 31, 2015, page 32, paragraph 114.
Consistent keying to the system price necessitates that a change in generation level at a generator be matched by a commensurate change in the load.” The choice of the GSO dispatch swing bus is inappropriate because it measures the change in losses relative to other generating units and other than relative to load.

137. The Commission’s view is that scaling down load to rebalance the system introduces a conceptual problem in terms of what is being measured in that it does not reflect what actually occurs on the system when a generating facility is, in fact, removed. In the real-world operation of the AIES, when a generating facility shuts down for periodic maintenance, trips off or is removed for any other reason, the AESO (except in relatively rare circumstances of constrained supply) dispatches other sources of generation to take its place, rather than scaling back load. Further, given the AESO’s considerable experience in dealing periodically with the real-time loss of output from individual generating facilities, it would be reasonable to expect that the ‘but-for’ analysis used in an ILF methodology should keep load constant and model what happens to total line losses when other generating facilities are dispatched to match the load.

138. Scaling down load creates an additional measurement problem. Not only must load be scaled back, the reason it is being scaled back is because output has fallen as well. In the result, the model must deal with two variables before measuring line losses to calculate loss factors. Within the ILF methodology, holding load constant when a generating facility is removed from the system more closely reflects how the AESO actually manages the AIES during a real world disruption in output. The AESO deals with only a single variable, namely, the mix of generating facilities that is dispatched to meet load, including output dissipated in line losses while meeting that load. Pursuant to the ILF methodology, the AESO then measures the corresponding change in aggregate line losses. The system being modeled when two variables come into play is not the same system when only one variable must be determined. In the Commission’s view, at least from a conceptual perspective, the better approach is to hold load constant and deal with the issue of rebalancing the system by dispatching additional output from other generating facilities on the system. Whether this approach is practical or feasible given information that is available to the AESO or that could be readily acquired by the AESO is addressed later in this section.

139. Lastly, Section 31(2) of the Transmission Regulation states that “the ISO must determine loss factors having regard to the following… (c) loss factors must be determined for each location on the transmission system as if no abnormal operating condition exists.” The Commission considers that scaling down load (were it to actually occur) would be an abnormal operating condition on the AIES. The AESO is very rarely called upon to scale down load, as it typically has access to enough supply to dispatch up the merit order until all load is served. In making this observation, the Commission is not suggesting that using distributed load as the swing bus to rebalance the system in order to calculate raw line loss factors under an ILF methodology would in itself violate Section 31(2)(c) of the Transmission Regulation. This is because the process of calculating raw line loss factors under an ILF methodology involves no actual curtailment of supply and no actual rebalancing of the system, whether by load scaling or output re-dispatch. The exercise is entirely hypothetical. No generating facility is actually being removed from the system in order to conduct a ‘but-for’ analysis. Rather, the Commission is simply underscoring that in the real world when supply is disrupted, it would be abnormal to rebalance the system by way of load scaling as opposed to merit order redispacth. Therefore the modelling results would be improved by better representing actual system conditions.
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140. Different parties to this proceeding have similarly observed that scaling down load in order to perform the ‘but-for’ analysis implicit in the ILF methodology is not without its difficulties. According to TransAlta:101

81. Load scaling raises three significant inter-related issues. First, it produces additional methodology-induced losses, which have no relation to a generating unit’s location on the system or contribution and impact on losses. Secondly, it creates what the AESO has acknowledged is an emergency condition on the system, and therefore violates the Transmission Regulation requirement that loss factors be determined for each location on the transmission system as if no abnormal operating conditions exist. Finally, load scaling effectively creates a swing bus that does not exist, and evidence in this Proceeding makes it clear that loss factors are very sensitive to the swing bus that is chosen.

141. ENMAX likewise identified difficulties associated with load scaling:102

84. The first technical reason that load scaling does not work is that it is not possible to simultaneously rebalance both real power (P) and reactive power (Q) except in the extremely unlikely event that the generator’s P/Q ratio is exactly the same as the P/Q ratio of the total load to be scaled. This follows simply from the fact that the AESO scales both the real and reactive components of each load using a single scale factor. The fact that MVAR imbalances are created by load scaling is one of the reasons why manual intervention may be required. As noted by the AESO in its response to AESO-EEC-2015JAN08-005(e):

Yes, when the generator or group of generators are removed from the load flow case, the reactive power component is removed as well. Adjustments to system voltage may need to be made in order to solve the load flow following the removal of the generator or group of generators. Several possible actions are available, including reactive power adjustments to nearby generating units and adjustments to other dynamic or static voltage control devices.

85. The second reason that load scaling does not work is that it is based on the assumption that the impedance of the transmission network is zero, which is an indefensible assumption given that loss factors would not be required if it were true. Real networks have non-zero impedance, which means that, while all generators serve all loads, they serve proportionally more nearby load than distant load. As Figure 2 on page 9 of EEC’s rebuttal to the Milner witness panel shows, the two generators’ shares of one of the loads changes as the impedance between the two legs of Dr. Stoft’s H network changes. On the AIES, Fort McMurray generators serve proportionally more Fort McMurray load than they do Medicine Hat load; uniform load scaling ignores that fact.

86. While the effect of non-zero line impedances is evident in the context of the H network, which used a dc case, the zero-impedance assumption strays even further from reality when reactive power is considered. Since reactive power does not travel well, scattering a generator’s reactive power injection or withdrawal across the province through load scaling leads to local voltage problems. As noted above and as reiterated by the AESO’s proposed loss-factor calculation procedure, voltage control problems may lead to manual intervention and/or a failure of the load-flow solutions to converge.

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102 Exhibit 790-X0411, ENMAX argument, July 31, 2015, pages 19-20, paragraphs 84-87.
87. The fact that load scaling can create convergence problems is evident in the AESO’s loss-factor calculation procedure. As already noted, the AESO’s loss-factor calculation procedure requires many steps to attempt to deal with the voltage problems, but each such step only serves to further conflate the effect of manual adjustments with the effect of removing the generator.

5.2 Keeping load constant and using the generic stacking order to rebalance the system

142. During the oral hearing, the Commission inquired about the possibility of balancing the system while undertaking a ‘but-for’ analysis by keeping load constant and dispatching other generating facilities to replace the output of the generating facility that had been removed. At that time, parties were focused on the use of the GSO to determine the dispatch order and rebalance the system.

143. As witness testimony during the oral hearing made clear, the GSO does not actually reflect, nor was it ever designed to reflect, which generating facility would be the next to be dispatched. Rather, the GSO was developed solely for use with the existing MLF/2 line loss methodology and only for the purpose of showing the typical output levels of each generating facility during a particular base case.

144. The AESO submitted that it did not support the GSO for re-dispatch for several reasons.103

42. While the AESO considered using GSO re-dispatch as opposed to distributed load, it was not selected for several reasons. First, GSO re-dispatch determines the impact of a generating unit relative to other generating units. This means that the impact would be dependent on the relative location of the generating unit removed and the one re-dispatched. This was explained by the AESO in the hearing as follows:

…if you are going to keep load constant and remove different generators from the loss factor calculations, the next generator that you dispatch should always be the same generator, no matter which generator you’re taking out. If you’re going to go up the generic stacking order from where you were, you will always be dispatching the same generator in respect.

So let’s imagine for a minute that the next generator you would go up to is in the Fort McMurray area. So then the impact on loss factors depends on which generator you’re actually taking out. If you’re taking out a generator in the southern part of the province, there will probably be a larger impact on loss factors because of the distance between the generator you’re taking out and the next one you dispatch.

If you’re taking out a generator near Wabamun or Sheerness, central part of the province, there would be a different impact. And if the generator you’re taking out is actually in the Fort McMurray area itself, there will probably be minimal impact because the next generator you’re dispatching up would be near it…

43. Second, because all units removed would result in the same generator(s) being re-dispatched in any given GSO, the results are very sensitive to the next generator in the stacking order. This would be particularly problematic given that the creation of the GSO

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103 Exhibit 790-X0409, AESO argument, July 31, 2015, pages 9-10, paragraphs 42-45.
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is a forecast, so it is created on at least a partly subjective basis, even though it would be based primarily on historical analysis.

44. Finally, in certain situations, there may not be enough energy available in the GSO to serve the forecasted load, such that the AESO would have to scale the load down in any event. In the proposed ILF by unit methodology, such situations would likely increase significantly, as the required re-dispatch would be each generating unit’s entire output rather than a marginal amount.

45. Accordingly, the AESO submits that scaling the load is consistent with the Commission’s findings in Decision 2014-110 and is preferable to GSO re-dispatch for the foregoing reasons.

145. The consensus of the parties, including the AESO, was that the GSO required more development if it were to be used to model the dispatch of other generating facilities to replace the output of the removed generating facility. Several parties, including Milner, also expressed a concern that the selection of the next generating facility or facilities to be dispatched pursuant to the GSO would not only significantly influence the calculation of loss factors, but would also be arbitrary.

5.3 Keeping load constant and using the merit order to rebalance the system

146. Another option for balancing the system as part of a ‘but-for’ analysis while keeping load constant is to use the merit order to determine the dispatch order. In this regard, it is important to observe that the AESO coordinates the second-by-second operation of the AES in real time 24 hours a day. Whenever a generating facility is removed from service (either because it trips off, it shuts down for maintenance, or is removed from the system for any other reason) the next generating facility or facilities in the merit order is/are dispatched by the AESO until the system rebalances. The Commission considers that the same process could be adopted as part of the ILF methodology. In particular, when the AESO is modeling the removal of a generating facility from the system it should be possible to calculate the incremental loss factor for the removed generating facility by holding load constant and rebalancing the system using the previous year’s merit order in each hour.

5.4 Commission findings regarding swingbus and number of base cases

147. Various parties made submissions on the meaning of the expression “relative to load” in Section 19(2)(d) of the Transmission Regulation.

148. Section 19(1)(b) of the 2004 Transmission Regulation states that the ISO must “determine the anticipated transmission line losses for a specified period of time and determine the average transmission system loss factor for that specified period.” Losses cannot be determined in a vacuum, as they depend on a myriad of system factors including, but not limited to, load, supply, transmission system elements, and temperature to name but a few. In order for the AESO to determine the anticipated transmission line losses for a specified period of time, the AESO must determine the anticipated system conditions for that specified period of time, and a key element of the anticipated system conditions is load.

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104 Tr. Vol. 1, April 16, 2015, page 163, lines 2-7 (AESO); Tr. Vol. 3, April 20, 2015, page 583, lines 11-17 (TransCanada); Tr. Vol. 3, April 20, 2015, page 623, lines 8-11 (Milner).
149. The Commission believes it is this load -- the forecasted load for a specified period of time -- to which the expression “relative to load” in Section 19(2)(d) of the Transmission Regulation refers. In particular, the Commission believes that it is the full load over a specified period of time, rather than load that has been scaled down in order to rebalance the system, that is being referred to in Section 19(2)(d).

150. In Decision 2014-110, the review panel set out the Commission’s role in the proceeding as follows:  

4 Section 19 to 22 of the 2004 Transmission Regulation
67. …The review panel also acknowledges that there are likely a number of different ways that the regulation and statutory requirements for a line loss rule could be met. The Commission’s role, as set out in Section 25(6)(b) of the 2003 Electric Utilities Act is to determine whether the 2005 Line Loss Rule is one of those ways by determining whether it is “unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the Act or the regulations.” [underline added]

151. The review panel was assessing whether the 2005 Line Loss Rule complied with the legislation. During that assessment, Dr. Burton stated the following on behalf of the AESO during an exchange with Mr. Wood, counsel for Enmax, at the oral hearing in Proceeding 2581:  

Q. And so to calculate the MLF, you first establish a base case, then you set the generating unit whose loss factor is to be calculated to be the swing bus, you perturb the loads by a small amount, you measure the change in the unit's output, you calculate the change in losses and divide that by the change in output to get the MLF. Have I got that right?
Q. And, Dr. Burton, is it your view that the software does a reasonably good job of estimating the change in losses and change in generation under the study conditions?
A. DR. BURTON: I'm going to backtrack a bit here. The actual calculation process to come up with the MLF by 2 is to look at -- to take a snapshot -- start from the snapshot of the system from the load flow. We take the data that went into that load flow, extract the admittance matrix for that load flow and, using the equations that we've put in our report, numerically differentiate the equations to come up with the -- of the generator -- the marginal -- what we call the marginal loss factor, and then we divide it by 2. We don't use perturbation method as sort of implied. This is all analytical. The only reason for accepting the perturbation method because that's easier to understand than the analytical method. [underline added]

152. That is, the AESO’s MLF/2 method of calculating loss factors implies a small perturbation and thus implies the use of distributed load to rebalance the system. However, as noted by Dr. Burton, the MLF/2 method only looks at one system state when calculating loss factors. Therefore, there is no need to make adjustments to the solved base case to account for any perturbation – there simply is no perturbation to account for. In this instance, the Commission sees no difference between using implied distributed load or an implied swing bus to account for an implied perturbation.

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153. Elsewhere in Decision 2014-110, the review panel provided its interpretation of various sections of the *Transmission Regulation*, including Section 19(2)(d):

78. Section 19(2)(d) requires that “the loss factor in each location must be representative of the impact on average system losses by each respective generating unit … relative to load.” Average system losses means the difference between total generation and total load during the period under consideration. A number of parties to the proceeding either were unsure why “relative to load” was included in Section 19(2)(d) or thought it was superfluous. In the review panel’s view, the words do have a meaning. The process of determining a single loss factor for each generating unit by combining the results of the calculation of discrete loss factors relative to distributed load (as opposed to use of a generating unit’s capacity relative to a swing bus, for example) in each of twelve base cases (as described above) is not inconsistent with the impact “relative to load” requirement. [underline added]

154. The finding of the review panel, namely that the AESO’s use of distributed load was not inconsistent with the impact “relative to load” requirement, was limited to the review of the MLF/2 methodology, under which the Commission saw no distinction between using distributed load and using generation redispatch as a swing bus to rebalance the system. The Commission did not consider ILF in Decision 2014-110.

155. Upon review of the evidence presented in Module B of Phase 2 of this proceeding, and especially when considering the use of two or more system states (such as in an ILF methodology) to calculate raw line loss factors, the Commission *does* see a distinction between using distributed load and using generation redispatch as a swing bus to rebalance the system after a system change has taken place.

156. In regards to the number of base cases used when calculating loss factors, in Decision 2014-110, the Commission stated:

72. …There were no concerns expressed by parties to the proceeding that the manner in which the 2005 Line Loss Rule averages the twelve raw (MLF/2) loss factors to arrive at the single raw loss factor number at each location was unreasonable. The review panel concludes that it is reasonable to use twelve representative snapshots as the basis for developing a single loss factor for each generating unit to be used in recovering each generating unit’s contribution to total line losses in a year.

157. In arriving at the above finding in Decision 2014-110, the sole question before the Commission was whether there was anything unreasonable, in theory or practice, in having the AESO use 12 representative base cases (as opposed to some other number) to develop a single annual line loss factor for each generating unit. The Commission was not directing its mind to whether a different approach might also be reasonable, if not preferable, were the objective somewhat different or were the exercise to involve multiple objectives including, for example, developing a reliable means to effect system rebalancing under a different (and legislatively compliant) line loss methodology. Based on the evidence in this proceeding, the Commission is of the view that the AESO’s plan to use 12 representative base cases as part of its proposed ILF by unit methodology may be improved upon so as to render more robust its entire ‘but-for’ approach to calculating line losses factors.

158. The Commission begins with the observation that dispatching up the merit order more closely reflects what would actually happen were a generating facility to be removed from
service. For this very reason, the Commission is also of the view that the merit order would be a practical and reasonable method of effecting system rebalancing when calculating loss factors while holding load constant under an ILF methodology. The Commission further observes that the AESO actually compiles 8,760 merit orders annually, one for each hour of every day of the year. Each of these 8,760 merit orders, in turn, could be employed as a (forecast) base case for the calculation of loss factors. While there was no consensus among the parties as to the ideal number of base cases to use for the purpose of calculating loss factors, several, if not all, parties agreed it is generally better to have more base cases than fewer. The AESO agreed that the use of more base cases is better,107 and ENMAX expressly supported using 8,760 base cases.108

159. There are several advantages to keeping load constant and using the merit order to determine the dispatch order and rebalance the system:

- It would simplify the AESO’s model of the system as only the generation mix would change (one generating facility would be removed and another generating facility or facilities would be added), rather than removing a generating facility and scaling down load.

- The calculation process would be simplified because the AESO would not have to calculate base cases. Rather, the AESO would simply rely on the actual 8,760 merit orders from the previous year (subject to adjustments for forecast additions and retirements of generation and transmission facilities).

- Keeping load constant more closely reflects actual system conditions and does not contravene Section 19(2)(c) of the Transmission Regulation.

- The use of 8,760 base cases would instill greater confidence in the forecast loss factors.

- It is likely that using the merit order will reduce the frequency of manual interventions. This is because the AESO constantly performs rebalancing in the real-time operation of the system by dispatching up and down the merit order placing particular emphasis on the reliable operation of the transmission system.

- It provides clarity and transparency to market participants, as the merit order is simply the publicly available record of offers into the pool from generating facilities during each hour of the previous year.

- The merit order embodies competitive aspects of the Alberta power pool, as it reflects the offers of competing generating facilities in actual market conditions.

- 8,760 raw loss factors can easily be aggregated into one annual loss factor for each generating facility connected to an MPID by taking a simple average, with no need for weighting. Indeed, the simple average is also the weighted average in this instance.

- Once an annual loss factor is calculated for each generating facility from the average of the 8,760 raw loss factors, the AESO would then normalize the annual loss factors (by shifting to recover the correct amount of losses in aggregate) and then clip and shift again.
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(if necessary) to comply with the collars imposed by Section 32(2)(g) of the Transmission Regulation.

160. The Commission recognizes that moving from 12 base cases to 8,760 base cases (even if the latter already exist in the form of the historical merit order, and new merit orders are automatically created every hour) would not be without administrative ramifications for the AESO. Conducting a ‘but-for’ analysis for each generating facility at each MPID 8,760 times a year could impose additional costs upon the AESO. These might include the need for software upgrades, modeling refinements, and/or new information processing systems and capabilities, and additional human resources to implement and manage these changes. The process of moving to 8,760 base cases per year for purposes of implementing the revised loss factor methodology may also further delay the effective date of the changed rule.

161. In view of these (and possibly other) potential impacts of employing the actual merit order (i.e., hourly output re-dispatch) instead of load scaling to rebalance the system every time a ‘but-for’ analysis is conducted for each generating facility on the system, the Commission requests that the following additional information, including recommendations as applicable, be provided by the AESO prior to making its compliance filing:

- What are the ramifications of the Commission’s direction to use 8,760 base cases in terms of the AESO’s operational processes including additional labour, equipment, processing and implementation time frames and associated costs in determining the required annual line loss factors using the Load Flow ILF method, the MPID (as adopted above by the Commission) as the location for measurement and the 8,760 merit orders to redispatch generation in the ‘but-for’ analysis?

- Is there a number of base cases less than 8,760 per year that would provide almost the same potential accuracy (e.g., a margin of error equal to X standard deviation(s) from the mean annual loss factor for each generating facility, or plus or minus some fraction of the mean annual loss factor for each generating facility, 95 times out of 100) in estimating an annual line loss factor for each individual generating facility uniquely associated with a single MPID as would 8,760 base cases?

- The AESO’s reasoning and the statistical analysis it employed (to be provided in full) in arriving at this smaller number of base cases.

- The AESO’s reasoning and, if applicable, the statistical analysis it employed (to be provided in full) in choosing between (1) a smaller, but still reasonably representative, number of actual merit orders per year (e.g., one merit order for the off peak, peak and super peak load hours on the system per day, or those three merit orders for those three hours in a given period of somewhat longer duration, say, between one day and one week, that respectively correspond to the off peak, peak and super peak load hours for each such period) and (2) a modified GSO or “averaged” or otherwise “representative” merit order for that number of base cases selected per day, per week or per month.

- The AESO’s estimated savings in time, human resources and financial expense associated with a recommended number of base cases less than 8,760.
• The AESO’s best estimate of when the revised line loss rule and loss factor methodology, including a process that relies on a recommended smaller number of base cases than 8,760, could be ready for implementation.

6 GENERAL ISSUES

6.1 Stage at which to recover value/volume of losses when calculating loss factors

162. Any ILF method, as shown in the evidence in this proceeding, will over recover the volume of losses and require that a shift factor be applied to each generator’s loss factor in order to collect the correct amount of losses. The question for Commission consideration is at what stage should the over recovery be addressed -- in each base case, or at the end of the year?

163. The AESO’s proposal is to recover the value/volume at each base case. The AESO submitted that adjusting loss factors at each step mitigates the risk of an anomalous raw loss factor materially affecting the final loss factor.\textsuperscript{109} ATCO proposed that the AESO simplify its aggregation from the 12 raw loss factors to the normalized annual loss factor by making it the simple volume weighted average.\textsuperscript{110} ATCO stated that the \textit{Transmission Regulation} does not require multiple rounds of adjustments and that one set of adjustments to fit raw loss factors inside collars will suffice.\textsuperscript{111}

164. The use of the merit order to calculate 8,760 base cases results in one raw loss factor for each hour, and eliminates the need for use of a volume weighted average (the weight applied to each loss factor is equal to 1). The \textit{Transmission Regulation} is silent with respect to when the volume of losses is to be recovered. In view of the Commission’s decision directing the AESO to use the merit order to calculate 8,760 base cases, or such lesser number of base cases as would accomplish essentially the same purpose, it may no longer be necessary or desirable for the AESO to recover the value/volume at each base case. The Commission expects the AESO to address this matter in its compliance filing.

6.2 Method and stage at which to apply collars

165. The Line Loss Rule applies clip, shift and, if necessary, linear compression to loss factors that are not within the collars specified in the \textit{Transmission Regulation}.\textsuperscript{112}

166. Capital Power submitted that the AESO should continue to use this clip, shift and compression process for determining loss factors.\textsuperscript{113}

167. ATCO proposed that the AESO, instead of compressing loss factors, use a simple shift and clip process so as to not unnecessarily distort the loss factor signal.\textsuperscript{114}

168. The AESO proposes in its revised rule to clip and shift loss factors repeatedly (without linear compression) until all loss factors are within the required collars. It has proposed this change because an iterative process of clipping and shifting is simpler than linear compression.

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\textsuperscript{109} Exhibit 790-X0409, AESO argument, July 31, 2015, page 20, paragraph 90.
\textsuperscript{110} Exhibit 790-X0072, ATCO evidence, March 12, 2015, page 4, paragraph 14.
\textsuperscript{111} Tr. Vol. 4, April 21, 2015, page 805.
\textsuperscript{112} Exhibit 790-X0177, AESO Concordance of Rule and Definitions, April 9, 2015, page 15.
\textsuperscript{113} Exhibit 790-X0412, Capital Power argument, July 31, 2015, page 3, paragraph 7.
\textsuperscript{114} Exhibit 790-X0072, ATCO evidence, March 12, 2015, PDF page 6, paragraph 14.
The AESO also noted that this step was expected to be used more frequently under an ILF methodology.\textsuperscript{115}

169. The Commission agrees with the AESO’s proposal to use an iterative clip and shift process as outlined in its June 19, 2015 proposed loss factor rule 501.10.\textsuperscript{116} The Commission finds that the AESO’s simplified proposal satisfies the Transmission Regulation’s requirement to use a common method to fit loss factors within the stated collars. The Commission further finds that this process should be done at the end of each year to preserve, to the extent possible, the economic signals inherent in the relative and absolute dispersion of line loss factors.

### 6.3 Consideration given to loss factors from previous years

170. Milner proposed that the Line Loss Rule be amended to provide for a weighted, five-year rolling average line loss factor. Milner submitted that this would give effect to the principle of stability in locational signals.\textsuperscript{117} Milner called upon rate principles in support of its argument on the grounds that line losses are collected through rates.

171. The AESO’s proposal does not consider historical loss factors, and it submitted that assigning weight to previous years will make loss factors less representative of the impact on average system losses by each generator. TransCanada submitted that Milner’s proposal for a weighted rolling average should not be approved for either retroactive or future application as generators with large credits or below average loss factors could use it to lock in those loss factors to obtain an even larger retroactive payment during Module C.

172. The Commission finds that a five year rolling average is not a requirement of the Transmission Regulation, and in phase one of this proceeding, the Commission did not find that it was unreasonable for the AESO to calculate line losses on a one-year basis. Further, the use of a five-year rolling average could potentially mute any remaining meaningful economic signal. The Commission anticipates that use of a historical merit order and the resulting 8,760 observations will provide a stable and realistic representation of line losses.

### 6.4 AESO procedure and verification of loss factors

173. The AESO filed a document in its reply evidence which “describes the steps the AESO uses to calculate transmission system losses with the system access service disconnected from the transmission system” (procedure document).\textsuperscript{118} The AESO did not include the procedure document within its revised rule and is not seeking approval of the procedure document itself. Although the procedure document is referred to in the AESO’s proposed revised rule, the AESO submitted that the procedure document does not form part of the rule.\textsuperscript{119} The AESO stated that the procedure “may be updated, potentially on an annual basis, to ensure that transmission system losses can be determined accurately and consistently, with repeatable results, for all system access services under the proposed Loss Factor Rule.”\textsuperscript{120}

\textsuperscript{115} Exhibit 790-X0180, AESO letter regarding amended line loss rule, April 9, 2015, page 3, paragraph 8.

\textsuperscript{116} Exhibit 790-X0345, AESO amended proposed line loss rule, June 19, 2015, page 6.

\textsuperscript{117} Exhibit 790-X0417, Milner argument, July 31, 2015, pages 21-22, paragraphs 71-73.

\textsuperscript{118} Exhibit 790-X0347, AESO Procedure to Determine System Losses for Loss Factor Calculations, June 19, 2015, page 1.

\textsuperscript{119} Exhibit 790-X0409, AESO argument, July 31, 2015, page 5, paragraph 17.

\textsuperscript{120} Exhibit 790-X0344, AESO reply evidence, June 19, 2015, page 2, paragraph 8.
174. Many parties in this proceeding argued that the AESO should be required to make line loss calculations publicly available, transparent and subject to an audit or verification process.\textsuperscript{121} TransAlta submitted that the phrase “publicly available” found in the title of Section 32 of the \textit{Transmission Regulation} requires some transparency in the derivation of loss factors and that market participants must have an understanding of how the AESO arrived at its loss factor calculations.\textsuperscript{122}

175. Milner submitted that it believes the AESO’s procedure document fully accounts for the exchange of views and information on the minutiae of the ILF process, and that the AESO has adequately addressed all reasonable concerns regarding verifiability and transparency.\textsuperscript{123}

176. The AESO disagreed with TransAlta’s interpretation of Section 32 of the \textit{Transmission Regulation} and submitted that Section 32(2) does not say that loss factor calculations, or the way in which loss factors are calculated, must be made available to the public.\textsuperscript{124} The AESO argued that it has expended considerable effort in making the loss factor calculation process transparent including: technical meetings, answering questions and filing its procedure document. However, the AESO stated that its efforts should have reasonable boundaries that do not include audits of loss factor calculations by market participants. The AESO submitted that if there is a disagreement, a market participant may first attempt to resolve the dispute informally through the AESO’s annual loss factor consultation process, failing which the market participant may engage the AESO’s dispute resolution process and/or may file a complaint with the Commission.\textsuperscript{125}

177. The Commission understands the desire by market participants to have clarity and certainty with regard to details of the procedures required to calculate line losses. However, the Commission is also mindful of the need to balance the AESO’s own need for reasonable operational discretion. The proposed procedure document is a very detailed, step-by-step methodology to be used by the AESO to determine an acceptable power flow solution and the resulting line losses, using a specific power simulation software package, chosen by the AESO for modeling the AIES transmission system with each system access service disconnected in turn. The Commission anticipates that significant changes to the procedure document will be necessary given that (1) this procedure document was developed during this proceeding; (2) “neither the AESO nor the Joint Parties used [it] when calculating loss factors filed in this Module B…”\textsuperscript{126} and (3) the directions in this decision call for use of the generation merit order to rebalance the power flow modeling rather than reliance on the AESO’s proposed distributed load as the swingbus. Accordingly, the Commission finds it sufficient that the revised line loss rule make express reference to the AESO’s procedure document. It is unnecessary to expressly include the AESO’s procedure document in the revised line loss rule.

178. The Commission also finds Section 32(2) of the \textit{Transmission Regulation} to mean that the loss factors themselves must be made public, and the Commission agrees with the AESO that this section is silent with respect to making public any underlying calculations. There is no

\textsuperscript{121} Exhibit 790-X0408, Powerex argument, July 31, 2015, page 7, paragraph 28; exhibit 790-X0413, ATCO argument, July 31, 2015, page 19, paragraphs 61-64; exhibit 790-X0435, Capital Power reply argument, August 28, 2015, page 20, paragraphs 70-73; and exhibit 790-X0403, Medicine Hat argument, July 31, 2015, page 75, paragraph 279.

\textsuperscript{122} Exhibit 790-X0416, TransAlta argument, July 31, 2015, page 8, paragraph 31.

\textsuperscript{123} Exhibit 790-X0417, Milner argument, July 31, 2015, page 33, paragraph 121.

\textsuperscript{124} Exhibit 790-X0437, AESO reply argument, August 28, 2015, pages 21-22, paragraphs 114-121.

\textsuperscript{125} Exhibit 790-X0409, AESO argument, July 31, 2015, pages 13-14, paragraphs 59-62.

\textsuperscript{126} Exhibit 790-X0437, AESO argument, August 28, 2015, page 22, paragraph 120.
statutory requirement to grant market participants a verification or audit process regarding line loss calculations. The Commission encourages the AESO to provide as much information regarding the line loss calculation process as would reasonably meet the needs of market participants including, for example, the ability to independently replicate the AESO’s line loss calculations, but leaves it within the AESO’s discretion to determine what this should entail. If a market participant wishes to complain about any AESO conduct relating to the procedures document, it may do so under Section 26 of the Electric Utilities Act.

6.5 AESO consultation

179. TransCanada submitted that “the AESO should be directed to begin intensive consultations with industry on the development and testing of the loss factor method the AUC selects immediately following the AUC decision. Such consultations should precede Module C and, if necessary, run in parallel with Module C.”

180. TransAlta submitted that “in the event… the Commission approves any version of ILF, significant additional work and consultation will be required to attempt to address the many deficiencies with the AESO’s ILF calculations.”

181. Parties have provided a significant amount of evidence and argument regarding possible revisions to the Line Loss Rule. In the Commission’s view, parties have had a greater opportunity to provide input into this revised rule than would have been possible through a consultation process. While the AESO is free to engage in further consultations with market participants, the Commission is not prepared to direct the AESO to do so.

7 ORDER TO THE AESO

7.1 Order

182. The Commission directs the AESO to change the current Line Loss Rule to implement the Commission’s findings in this decision. In order to facilitate the compliance process, the AESO is directed to file by February 1, 2016, a plan (including a timeline) to develop a revised line loss rule that implements the Commission’s findings in this decision. Once the implementation plan is reviewed and approved by the Commission, the AESO will be directed to submit its changed line loss rule in a compliance filing for Commission review and approval by a date to be determined.

7.2 Effective date of the changed line loss rule

183. There was no consensus among parties as to the date upon which the changes to the current Line Loss Rule should take effect. Some parties urged that the Commission set as early an effective date as possible given how long the unlawful Line Loss Rule has been in effect and

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127 Exhibit 790-X0419, TransCanada argument, July 31, 2015, page 58, paragraph 172.
128 Ibid., paragraph 175.
129 Exhibit 790-X0429, TransAlta reply argument, August 28, 2015, page 23, paragraph 80.
their concern that they continue to be assessed unjustly discriminatory line loss charges to their financial detriment.\textsuperscript{130}

184. Section 25(7) of the 2003/07 \textit{Electric Utilities Act} prescribes that the ISO must file with the Commission an ISO rule that is revised pursuant to a Commission order under Section 25(6)(e), as is the case here. Section 25(8) requires that the Commission publish the revised rule. Section 25(9), in turn, stipulates that the earliest date upon which the changes to the current Line Loss Rule may come into effect is the day on which the AESO files the revised rule with the Commission. The effective date of the changed rule, in other words, is governed by the express terms of the \textit{Electric Utilities Act}. Beyond directing that the AESO implement the changes ordered by the Commission and file the changed line loss rule as quickly as circumstances permit and as is reasonably possible, the Commission is without authority to alter these statutory provisions in order to expedite the effective date of the changes to the current Line Loss Rule as certain parties have requested.

185. The Commission recognizes that the changes it has directed the AESO to make to the current Line Loss Rule are significant, and that related changes to the AESO’s internal processes and information gathering and processing capabilities will likely also be required in order to comply with the Commission’s directions. The Commission understands that these are not changes that can be implemented and operationalized in a matter of days or a few weeks. The Commission is also mindful that there may be unanticipated implementation issues or complications, technical or otherwise, which the AESO may wish to bring to the Commission’s attention for further consideration and direction. The AESO has leave to do so as it considers necessary or advisable.

186. The AESO expressed concerns about the need to comply with Section 31(2)(a) of the \textit{Transmission Regulation}, which requires loss factors to apply for a period of at least one year but not more than five years. The AESO’s concern was that it would not be able to have a line loss rule in place before January 1, 2016. The Commission notes that the AESO has several options at its disposal, such as lengthening the time that the 2015 loss factors are in place and specifying that the initial term for the new loss factors would remain in effect for more than 12 months. This would allow the AESO to return to its practice of applying loss factors on a calendar year basis after the initial term of the loss factors calculated under the changed line loss rule.\textsuperscript{131}

187. The Commission also finds that the effective date of this changed ISO rule will not affect or in any way limit the Commission’s parallel authority, pursuant to sections 119(4) and 121 of the \textit{Electric Utilities Act}, to: (1) adjust line loss charges from January 1, 2006 until the effective date of new loss factors calculated pursuant to the changed line loss rule and (2) determine final line loss charges in Module C of this proceeding up to the effective date of the new loss factors calculated pursuant to the changed line loss rule.

\textsuperscript{130} Exhibit 790-X0441, AESO Report on Consultation Regarding the Timing for Implementation of a New Loss Factor Rule and Methodology, October 13, 2015.

\textsuperscript{131} For example, the 2015 loss factors could remain in effect until July 31, 2016. The new line loss factors could then come into effect on August 1, 2016 and remain in effect until December 31, 2017.
Dated on November 26, 2015.

**Alberta Utilities Commission**

*(original signed by)*

Willie Grieve, QC
Chair

*(original signed by)*

Neil Jamieson
Commission Member

*(original signed by)*

Bohdan (Don) Romaniuk
Acting Commission Member
APPENDIX 1 – PROCEEDING PARTICIPANTS

<table>
<thead>
<tr>
<th>Name of organization (abbreviation)</th>
<th>counsel or representative</th>
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<tbody>
<tr>
<td>Alberta Electric System Operator (AESO or ISO)</td>
<td>David Holgate – Stikeman Elliot LLP</td>
</tr>
<tr>
<td>ATCO Power Canada Ltd. (ATCO)</td>
<td>Marie Buchinski – Bennett Jones LLP</td>
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<tr>
<td>Capital Power Corporation (Capital Power)</td>
<td>Douglas Crowther – Dentons Canada LLP</td>
</tr>
<tr>
<td>City of Medicine Hat (Medicine Hat)</td>
<td>Roger Belland</td>
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<tr>
<td>ENMAX Energy Corporation (ENMAX)</td>
<td>David Wood – Torys LLP</td>
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<tr>
<td>Milner Power Inc. (Milner)</td>
<td>Monte Forester</td>
</tr>
<tr>
<td>Powerex Corp. (Powerex)</td>
<td>Chris Sanderson – Lawson Lundell LLP</td>
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<tr>
<td>TransAlta Corporation (TransAlta)</td>
<td>Laura Marie Berg</td>
</tr>
<tr>
<td>TransCanada Energy Ltd. (TransCanada)</td>
<td>Nadine Berge</td>
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Alberta Utilities Commission

Commission panel
Willie Grieve, QC, Chair
Neil Jamieson, Commission Member
Bohdan (Don) Romaniuk, Acting Commission Member

Commission staff
John Petch, Commission Counsel
Andrew Davison, Senior Market Analyst
Greg Andrews, Market Analyst
APPENDIX 2 – ABBREVIATIONS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Name in full</th>
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<tbody>
<tr>
<td>AESO</td>
<td>Alberta Electric System Operator</td>
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<td>AIES</td>
<td>Alberta Interconnected Electric System</td>
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<td>ATCO</td>
<td>ATCO Power Ltd.</td>
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<td>AUC</td>
<td>Alberta Utilities Commission</td>
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<td>Capital Power</td>
<td>Capital Power Corporation</td>
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<td>DOS</td>
<td>demand opportunity service</td>
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<td>EEC or ENMAX</td>
<td>ENMAX Energy Corporation</td>
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<td>exception list</td>
<td>exhibit 790-X0289</td>
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<td>ILF</td>
<td>incremental loss factor</td>
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<td>GSO</td>
<td>generic stacking order</td>
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<td>IOS</td>
<td>import opportunity service</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>LFA</td>
<td>load flow approach</td>
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| Line Loss Rule | 2005 to current  
|               | ISO rule 9.2: Transmission Loss Factors and Appendix 7: Transmission Loss Factor Methodology and Assumptions and/or ISO rules Section 501.10 Transmission Loss Factor Methodology and Requirements |
| Medicine Hat | City of Medicine Hat |
| Milner       | Milner Power Inc. |
| MLF/2        | marginal loss factor divide by two |
| MLL          | marginal line loss |
| MPID         | metering point identifier |
| Powerex      | Powerex Corp. |
| procedure document | exhibit 790-X0347 |
| proposed line loss rule | exhibit 790-X0345 |
| RLF          | raw loss factor |
| STS          | supply transmission service |
| TransAlta    | TransAlta Corporation |
| TCE or TransCanada | TransCanada Energy Ltd. |
| XOS          | export opportunity service |