Decision 2012-104

Alberta Utilities Commission

Milner Power Inc.

Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

April 16, 2012

The Alberta Utilities Commission
Decision 2012-104: Milner Power Inc.
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Application No. 1606494
Proceeding ID No. 790

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1 Introduction

1. The essence of the complaint by Milner Power Inc. (Milner) in this proceeding can be illustrated by the following example. In a remote town, far away from any water source, the local inhabitants rely on a large reservoir for their water supply. The water supply operates on a non-profit basis. Those who drink from it are charged by the volume they remove. Those who add to the reservoir receive credit for their contribution. An individual will be charged one dollar for a litre of water taken out. Another individual who brings a litre bottle full of water and empties it into the reservoir will receive a dollar for adding to the stock of water. This scheme, the inhabitants believe, will charge those who use water while rewarding those who replenish the supply. If someone added four litres of water but decided to take out a litre at the end, the result would be a net credit of three dollars to the individual.

2. Then one day, a new water pricing regime is put into place. Regardless of how much water an individual takes from or adds to the reservoir, the charge or credit will be based on the last action of the individual, rather than on the net amount of water added or removed. If an individual comes along and empties one hundred litres of water into the reservoir and then chooses to take out one litre (for the long road trip back home), he is in for a surprise when he arrives at the till to collect payment. Instead of receiving ninety-nine dollars for what he thought was a net addition of ninety-nine litres of water, he receives a bill for one hundred and one dollars. The new pricing system, it is explained to him, considers his final action of withdrawing one litre as representative of his average impact on the system. He is therefore charged a dollar per litre for all the litres of water both those added and those removed. When the cashier is asked for the rationale behind the new rule, the basic argument given is that "we consulted widely and this seemed like the best idea at the time. Plus it collects the correct dollar figure for total costs." As one can expect, this new system causes much consternation among those bringing in water. One can only imagine that in the long-run, those water suppliers will either bring in less water than before or not bring in any water at all.

3. Although this example is simplified, it demonstrates the main complaint that Milner has against the Alberta Electric System Operator's (AESO) Line Loss Rule. In accordance with this rule, generators are charged one half[1] of the associated line loss of the last unit of energy produced as the price for all units generated, regardless of the losses or reductions in losses caused by these units of energy.[2] Milner can be analogized to the individual who received the $101 bill. When Milner's generation unit reduces line losses, this is analogous to the individual who added the one hundred litres of water into the reservoir. When Milner's last unit of

[1] Under the AESO's line loss methodology, as will be explained below, the generating unit is charged a price related to half of what the last unit caused. In the water example, it would be as if the individual was billed fifty cents per litre and received a total bill of $50.50.

[2] Milner also complains about the role of transmission must run (TMR) generation in computing the line losses. This issue is dealt with in Decision 2012-105.

generation causes a small increase in line losses, this is analogous to the individual when he took out the last litre of water. Milner believes its generating unit is located where Milner believes that it lowers average system losses and, yet, under the current line loss methodology gets charged.

4. In support of its rule, the AESO and the Generator Group,[3] argue that the rule reasonably complies with the law and was developed in a fair process that took into account various viewpoints. Furthermore, the AESO's rule is also mathematically correct in that it calculates the right aggregate amount of line losses from all parties.

5. For reasons that will become apparent below, the Alberta Utilities Commission (AUC or the Commission) finds that the AESO's Line Loss Rule is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of [the *Electric Utilities Act*] or the regulations" such as the *Transmission Regulation* (AR 174/2004).[4] As such, the Commission finds that the complaint raised by Milner is upheld and that the Independent System Operator (ISO) Line Loss Rule contravenes Section 19 of the *Transmission Regulation*.

6. The Commission also finds that the AESO Line Loss Rule as it exists today "does not support the fair, efficient and openly competitive operation of the market", and that the Line Loss Rule "is not in the public interest." The implications of this finding will be discussed later in Section 8 below.

1.1 The procedural history of this proceeding

7. This proceeding comes to the Commission as a result of a complaint filed by Milner on August 17, 2005, with the Commission's predecessor the Alberta Energy and Utilities Board (EUB or Board).[5] The Board dismissed the Complaint, Milner appealed to the Court of Appeal of Alberta, and that court agreed with Milner that the dismissal was unwarranted.[6] The court sent the complaint back to the Commission to evaluate on the merits.[7]

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[3] See footnote 7 for details on all the participants.

[4] In this decision, the term *Transmission Regulation* refers to *Transmission Regulation* (AR 174/2004), unless otherwise noted.

[5] On August 17, 2005, pursuant to sections 25 and 26 of the *Electric Utilities Act* in force at the time, Milner submitted a written complaint (Complaint) to the Alberta Energy and Utilities Board (EUB or the Board) about the Independent System Operator (ISO) rule 9.2 – *Transmission Loss Factors* and ISO Rule Appendix 7 – *Transmission Loss Factor Methodology and Assumptions* (collectively the Line Loss Rule).

[6] On December 30, 2005, the Board issued EUB Decision 2005-150 in which it denied Milner's complaint and indicated that the AESO was free to implement its Line Loss Rule effective January 1, 2006. Milner appealed this decision to the Court of Appeal of Alberta. On July 29, 2010, the Court of Appeal of Alberta released its judgment in *Milner Power Inc. v. Alberta (Energy and Utilities Board)*, 2010 ABCA 236. That judgment vacated EUB Decision 2005-150 and remitted the matter to the Board.

[7] Pursuant to the provisions of the *Alberta Utilities Commission Act* and the regulations made thereunder, the Commission had been established in 2008 and made responsible for continuation of administrative proceedings pending against the Board. On September 20, 2010, the Commission issued a notice of Commission initiated proceeding as directed by the Alberta Court of Appeal. The Commission initiated proceeding was assigned Application No. 1606494 and Proceeding ID No. 790.

In response to the notice of proceeding, the Commission received a statement of intent to participate from each of the following parties by the October 15, 2010 deadline:

(a) AESO
(b) Alberta Direct Connect Consumer Association (ADC)
(c) ATCO Power Ltd. (ATCO)

8. In order to simplify the adjudication of the matters being considered, on February 28, 2011, the Commission bifurcated the hearing into two phases. The first considers "whether the AESO's Line Loss Rule contravened Section 19 of the *Transmission Regulation*", and the second determines what remedy, if any, could be awarded to Milner in the event the Commission found for Milner in the first phase. A division of the Commission, consisting of Tudor Beattie, QC, Bill Lyttle and Moin Yahya, heard the first phase of this proceeding at the Commission's hearing room at the AUC offices in Calgary on October 19 through 22, 2011. The Commission considers the record for Proceeding ID No. 790 closed on January 17, 2012.

9. In reaching the determinations contained within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

10. Due to the voluminous submissions by all parties, much of it technical or mathematical in nature, the Commission in considering the issue below has dispensed with its traditional format of reciting every party's submission at each juncture of the decision. Those who wish to read them can do so in the record. All the views and submissions of the parties were extensively considered and carefully examined. The result is the analysis that follows.

1.2 The complaint

11. The grounds of Milner's Complaint were that the Line Loss Rule was inconsistent with or in contravention of the *Transmission Regulation* and/or the *Transmission Development Policy* and is otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory, in that the Line Loss Rule:[8]

(a) Was established and is intended to be implemented by the AESO without the AESO first complying with the Board's outstanding directives;

(b) Fails to "reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses," contrary to subsection 19(1)(a) of the *Transmission Regulation*;

(d) Capital Power Corporation (Capital Power)
(e) ENMAX Energy Corporation (ENMAX)
(f) Industrial Power Consumers Association of Alberta (IPCAA)
(g) TransAlta Corporation (TransAlta)
(h) TransCanada Energy Ltd. (TransCanada)

On July 28, 2011, the Generator Group identified itself as comprising Capital Power, TransAlta and TransCanada (Exhibit 204.01 – Generator Group Evidence, page 2 of 20). The Generator Group clarified that these companies elected to file joint evidence and argument in order to avoid duplication, and that each of the companies had reviewed and endorsed the submissions of the Generator Group (Exhibit 295.02 – Generator Group Argument, page 1).

On December 3, 2010, the Commission issued the first version of the schedule for the proceeding. Throughout the proceeding the schedule was revised on multiple occasions, either at the request of participants to accommodate their availability, or initiated by the Commission in order to ensure a fair and equitable process for the participants.

[8] Exhibit 0002.01, Milner Complaint, August 17, 2005, pages 2 to 3.

(c) Fails to ensure 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," contrary to subsection 19(2)(d) of the *Transmission Regulation*;

(d) Contravenes the principle of stability in locational signals essential to the underlying purposes of the *Transmission Regulation* and the *Transmission Development Policy*; and

(e) Determines loss factors for each location on the transmission system under abnormal operating conditions by including the dispatch from TMR generators, contrary to subsection 19(2)(c) of the *Transmission Regulation*, and contrary to the underlying purposes of the *Transmission Regulation* and the *Transmission Development Policy*.

12. To examine Milner's Complaint, the basics of line losses are discussed followed by a discussion of the various legislative frameworks that govern the Complaint.

2 Basic introduction to transmission line losses

13. Like water evaporating from an open irrigation canal, when electricity is transmitted across the various transmission wires, some of the energy disappears. Typically, the energy is lost through heating in the transmission line and grid transformers (primarily due to the resistance of the line material and internal transformer wiring). Transmission line losses, at the most basic level, can be defined as the difference between the amount of energy that is received onto the transmission system from the generator points of metering and the amount of energy that is delivered from the transmission system to the bulk metering points for eventual consumption.

14. Losses on a transmission line vary as a function of the length of the line. The closer the generator is to load, or that which is consuming the generated power, the less line losses there are. Keeping everything else constant, with equivalent power flow, total losses on a 100 kilometre transmission line will be approximately ten times the total losses on an identical transmission line that is only 10 kilometres in length.[9]

15. Losses on a transmission line also vary as the square of the power flow on the line. Keeping all other factors constant, a transmission line with a power flow of 100-megawatts (MW) will incur four times the amount of losses as the same line with a power flow of 50 MW.[10]

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[9] This is a first-order approximation of the differences in losses on a 100 kilometre transmission line versus a 10 kilometre transmission line.

[10] **Power** is an instantaneous amount of electricity and is measured in watts (kilowatts (kW), megawatts (MW) or gigawatts (GW)). Line losses are an instantaneous measure of the power that is lost over a transmission line and is a function of the power that is flowing over the transmission line. Line losses are measured in MW. Loss factors are expressed as a percentage and are the relation between the amount of power flowing over a line and the amount of power lost from that line.

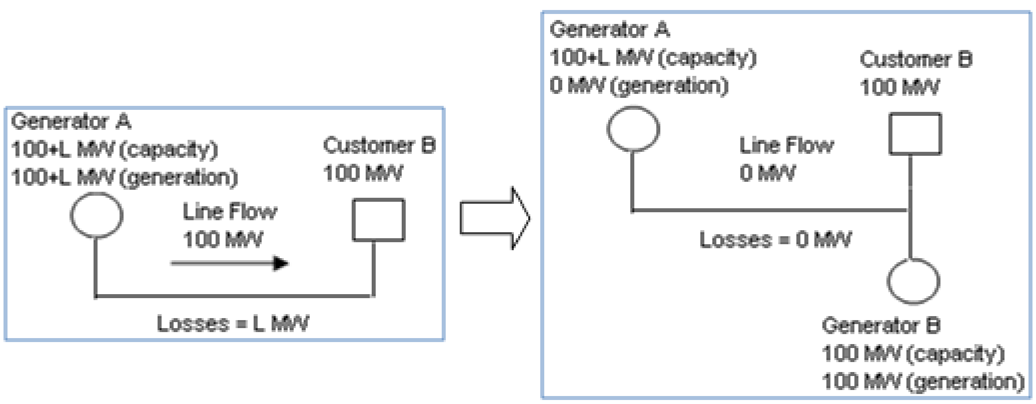
Energy is a measurement of power over a specified period of time, usually an hour, and is usually expressed in kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).

For generators, a one-MW power plant is capable of producing one-MW of power. If the plant produced one-MW of power at a constant rate for 1 hour, it has produced one-MWh of energy. For line losses, a transmission line could be designed to carry 100-MW of power and lose 10-MW through losses. If the line operated a full capacity for 1 hour it would have flowed 100-MWh of energy and lost 10-MWh through losses.

Such losses can therefore be expressed mathematically as $L = aP^2$, where a is a constant, and P is the power flowing on the line.

16. Generators can either increase or decrease total line losses. To understand this, consider the following simplified example. The Commission notes that these examples are illustrative only of what is occurring on the system and for example a generator cannot direct its generation towards a particular customer, but to the entire system. Generator A is located some distance from Customer B. If Customer B requires 100 MW at any point in time, Generator A must generate 100 MW plus a small amount that is lost when the electricity is transmitted over the transmission lines servicing this customer (say an amount denoted by L). Now assume that Generator B locates right next to Customer B and is able to generate 100 MW. As this generator is right next to the customer, there will be no line losses associated with Generator B's transmission of power to Customer B. Generator B has saved the system the line losses associated with Generator A's original power generation, i.e., Generator B has saved the system L losses. If one were to price these savings to the system, one would calculate the price associated with the saved losses at that time, say p, and multiply the savings by the price, i.e. pL.[11] For simplicity, the Commission shall assume that the price charged is set equal to one. This will allow the mathematical representation of power and energy using the same terms.

Figure 1. Simple example of Generator A, Generator B and Customer B



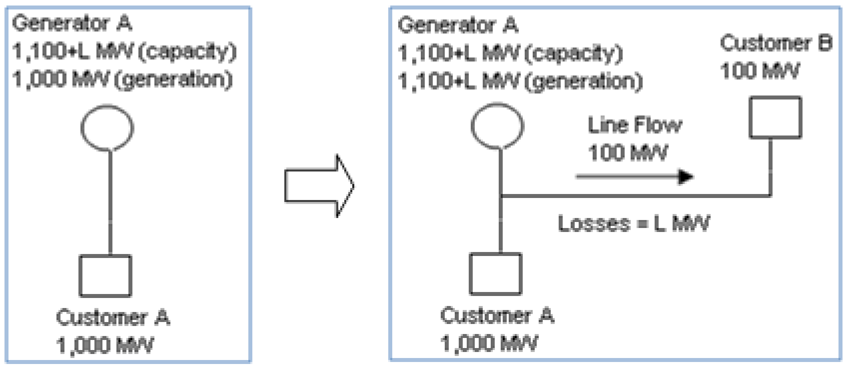
17. Now consider this next example in Figure 2. Generator A is located next to Customer A. As such, there are no line losses in this system. Generator A has the capacity to generate a little more (L) than 1,100 MW, but Customer A only requires 1,000 MW. Hence, Generator A only generates 1,000 MW and generates no line losses due to its immediate proximity to Customer A. Now Customer B comes along and requires 100 MW of power for its needs. Now if Generator A wishes to generate an extra 100 MW to send towards Customer B, it will also have to generate

In this proceeding we refer to the amount of power that is lost at any instant in terms of MW, and we refer to the total amount of energy lost to line losses in a year in terms of MWh or GWh, which are industry standards. The AESO, through the line loss methodology (regardless of MLF or ILF or other technique), must convert instantaneous power losses (in MW) into yearly energy losses (in MWh or GWh) that must recover the total cost of transmission losses.

11 The actual value of losses is not simply the volume of losses multiplied by the average pool price. This is because the volume of losses varies constantly with changing system conditions. As submitted by the AESO in Exhibit 0205.01, AESO Evidence, June 28, 2011, page 2, the value of those losses is found by multiplying the volume of losses in any hour by the hourly pool price, and then summing those values throughout an entire year.

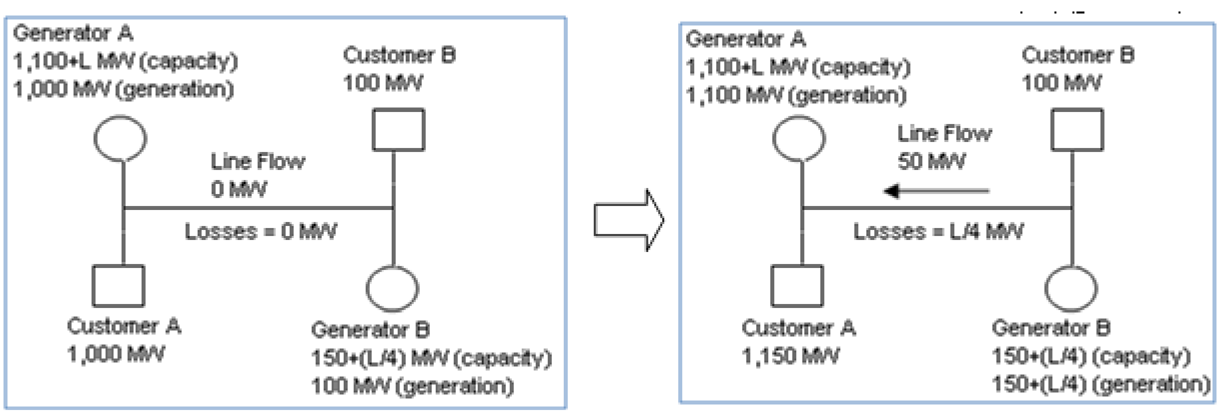
a little extra over 100 MW (as before say an amount denoted by L) in order to account for some line losses associated with the transmission of electricity to the new but remote Customer B. The result is that the system is generating (1,100+L) MW, but only consuming 1,100 MW. Generator A is responsible for L in terms of losses.

Figure 2. Simple example of Generator A, Customer A and Customer B



18. Suppose that Generator B is now built next to Customer B and has a capacity of a little over 150 MW. It decides to generate 100 MW in order to service Customer B. The effect is a reduction in losses by L. The story in this example does not end here, however. Rather, now suppose that the demand for power by Customer A expands by an extra 150 MW. Clearly between the two generators A and B, there is enough capacity to service the extra demand. Generator A adds 100 MW of power into the system while Generator B also adds 50 MW of power. But while Generator A is not causing any losses from the extra generation, Generator B is now causing line losses by sending some of its power to Customer A. In fact, it is now causing $L/_4$ in additional losses.[12]

Figure 3. Revised example of Generator A, Generator B, Customer A and Customer B



19. At the end of day, there are $L/_4$ in total losses for a total of 1,250 MW consumed. Notice that if Generator A had to meet the entire demand by both customer A and B (assuming it had

12 This is because $L = aP^2$. Since P in this example is 50, or half of the 100 MW in the first part of the example, the losses will be a quarter of what they were when the 100 MW was being sent by Generator A to customer B, or $L/_4$.

the capacity), there would have been losses in the amount of L for consumption of 1,250 MW. As such, Generator B's existence and generation has now reduced the total losses by $\frac{3}{4}L$.

20. In Alberta, the overall cost of transmission line losses is borne by generators.[13] Thus loss factors are a method of distributing the cost of line losses amongst all generators. Some generators receive a credit (for reducing transmission line losses) and other generators pay a charge (for increasing transmission line losses) depending on their location and contribution to losses on the transmission system. Hence, the term contribution throughout this decision should be understood as referring to both increases or decreases in line losses. However, line losses are also important to consumers because in the end it is consumers, including industrial, commercial and residential consumers, that ultimately pay for electricity generated in Alberta, whether that electricity is used to serve load or to cover transmission line losses.

21. The question in this proceeding is how to allocate the losses and reductions among the various generators in the province. In the prior stylized example, there are many ways to allocate these losses between generators A and B. To do so first, some terminology must be introduced.

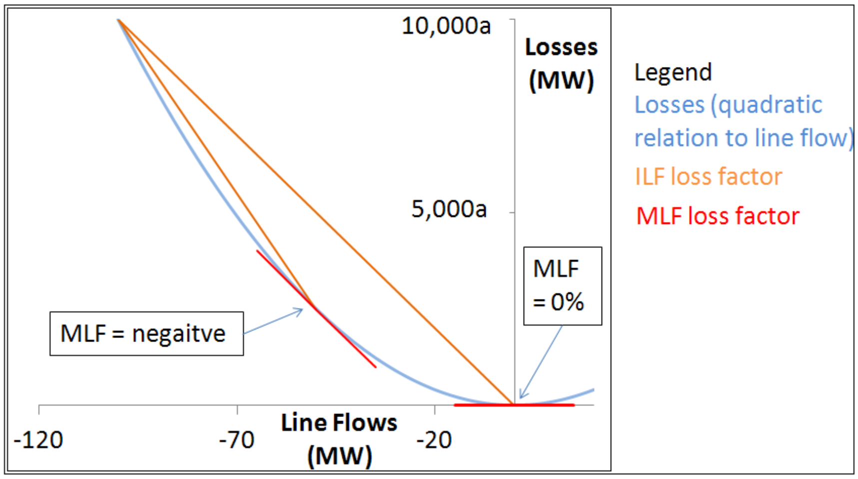
22. The term marginal loss factor (MLF) refers to the last loss caused by the last unit of power generated. Since the relationship between line losses and the power generated is squared in nature, as more units of power are produced the losses are increasing at an increasing rate.

23. As the formula for line losses is $L = aP^2$, the formula for MLF is $MLF = \frac{dL}{dP} = 2aP$. Thus, as each unit of power is generated, that additional unit of generation creates twice its value (scaled by an amount *a*) in terms of losses to the system. So, in our example, when Generator A was the only generator on the system, when Customer B first started power, and when Generator A decided to service Customer B, imagine the following sequence of events. The total losses when all the units are being used is $L = aP^2$. If the generator is delivering 100 units, then the total losses are 10,000*a*. Now if it generates one more unit for a total of 101, the total losses are 10,201*a*. There is an extra 201*a* in losses. Similarly, if the generator generated 99 units and then added one more for 100 units, the losses would go from 9,801*a* to 10,000*a* or an increase of 199*a*. At 100, therefore, the extra or marginal losses are around 200*a*, which is what the formula $MLF = \frac{dL}{dP} = 2aP$ conveys in exact mathematical terms.

24. Once, however, Generator B comes on to serve Customer B, and after Generator A is serving Customer B by generating the extra 100 MW, the losses decline. For each extra unit of power that Generator B sends to Customer B, the total system losses will decline from 10,000*a* (or 100^2a) to zero when Generator B is producing 100 MW to exclusively serve Customer B's load of 100 MW. The MLF of Generator B here is, therefore, negative as it reduces losses until it finally has an MLF of zero when it is generating 100 MW of power and not affecting losses. This can be seen in Figure 4.

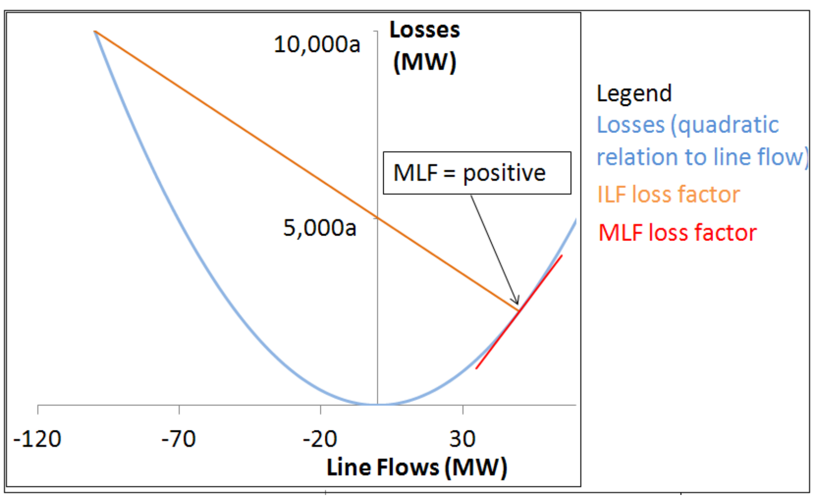
13 Section 22 of the *Transmission Regulation*; sections 35 and 36 of the current *Transmission Regulation*; Section 30(3)(a) of the *Electric Utilities Act*.

Figure 4. MLF – Losses and Line Flow



25. Now when Generator B decides to send the extra 50 MW back to Customer A, this causes losses in the amount of 2,500*a*. The marginal losses go from zero to 100*a* as can be seen in Figure 5.

Figure 5. MLF – Losses and Line Flow



26. While the marginal loss methodology allows the measurement of the impact of the last unit produced, or for that matter each unit being produced, another way to attribute losses to a generator is to look at the discrete impact before and after the generator produces all of its units of power. This is known as the incremental approach. So, in the previous example, when Generator A initially serves Customer B, the incremental losses are the difference between the losses caused after Generator A serviced B and those losses caused before servicing Generator B. The incremental loss factor (ILF), therefore, measures losses over a longer period of time or power flow and in a discrete lumpy fashion as opposed to the MLF approach which measures the marginal losses for each power flow at any point in time.

27. In the previous example, the incremental losses for Generator A when it initially serves Customer B would be $a100^2 – a\,(0)^2$ or 10,000*a*. For Generator B, when it only generates the

initial 100 MW, the incremental losses would be 0-10,000a or -10,000a. However, when it generates an extra 50 MW, its incremental losses go to 2,500a-10,000a= -7,500a. The actual ILF would be calculated as $ILF = \frac{L(P) - L(0)}{P}$, where $L(P)$ is the total losses calculated at the final output of the generator and $L(0)$ is the total losses associated with the generator before it generates anything.

28. Having explained the various concepts, the Commission now turns to the impugned AESO Line Loss Rule methodology.

3 The AESO Line Loss Rule methodology under review

29. The AESO's methodology for calculating line loss factors, and hence the charges or credits that each generator must pay or will receive, is unsurprisingly complex. That being said however, it can be simplified as follows. The AESO takes an averaged snapshot of the line losses of a generating unit during twelve periods throughout the year and then averages those snapshots using various methodologies. From these averaged snapshots, a forecast single average loss factor for that generating unit for the coming year's losses is produced.

30. What is measured and simulated in the snapshot is the marginal loss factor for each generating unit, which is then divided by two.[14] In other words, the AESO uses a MLF/2 approach to calculate the loss factors. These factors are typically expressed in the form of percentages and are then converted into energy so that ultimately they can be priced using the prices in the wholesale energy market. The new loss factor is multiplied by the price and energy produced in any hour, and this is then summed for all the energy that the generating unit produces in the year.

4 Regulatory framework: legislation and regulation

31. Given that this proceeding is a result of a complaint that was filed in 2005, the Commission must look to both the *Electric Utilities Act*, S.A. 2003, c E-5.1[15]and *Transmission Regulation* as they were worded then.

32. The *Electric Utilities Act* then existed in a version from June 1, 2003 to April 19, 2007. Since April 20, 2007, another version of the *Electric Utilities Act* was passed, with the last set of amendments effective since May 13, 2011 (*Electric Utilities Act* 2011).[16] Similarly, the *Transmission Regulation*, enacted pursuant to the *Electric Utilities Act*, has had several versions enacted over the years. In 2005, AR 174/2004 was the *Transmission Regulation* in effect from

[14] None of the parties challenged the actual methodology of measuring or taking the snapshot and then averaging the twelve snapshots. Details can be found in Exhibit 0223.02, AESO's 2006 Transmission Loss Factor Methodology Decision Document, October 18, 2005.

[15] In this decision, the term *Electric Utilities Act* refers to *Electric Utilities Act*, S.A. 2003, c E-5.1, unless otherwise noted.

[16] The *Electric Utilities Act* has been through several versions, the first being from June 1, 2003 to April 19, 2007. The second version was in effect from April 20, 2007 and December 31, 2007, the third version from January 1, 2008 and September 30, 2009, the fourth version between October 1, 2009 and December 8, 2009, the fifth version between December 9, 2009 and October 31, 2010, and the sixth version between November 1, 2010 and May 12, 2011. The current version has been in effect since May 13, 2011.

September 1, 2004 to April 10, 2007. Currently, AR 86/2007 has been the *Transmission Regulation* in effect since October 29, 2010 (*Transmission Regulation* 2010).[17]

4.1 The *Electric Utilities Act*

33. *M*ilner's complaint was filed in 2005, and hence the Commission's analysis will look to *Electric Utilities Act an*d *Transmission Regulation* for its l*egal guidance. As will b*ecome apparent later in Se*ction 5.4 of this deci*sion*, the Commission will al*so evaluate the complaint under the current versions of the *Electric Utilities Act* and *Transmission Regulation* throughout this decision. As such, the relevant portions of the *Electric Utilities Act* and *Transmission Regulation will be discussed* next.

34. Th*e Electric Utilities Act* is the relevant legislation for this complaint. The *Electric Utilities Act* starts by explaining the purpose of the legislation. This is done in Section 5, which is almost identical in both *Electric Utilities Act* 2003 and *Electric Utilities Act* 2011.[18] According to Section 5 of *Electric Utilities Act* 2003, the purposes of the *Electric Utilities 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, the Market Surveillance Administrator 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;
>
> ...
>
> (h) 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.

17 There is one more piece of possibly relevant and persuasive document, namely the *Transmission Development Policy*, which Milner relies upon heavily. As the Commission finds for Milner on its main complaint without relying on the *Transmission Development Policy*, the Commission does not engage the question of what weight it should place on the *Transmission Development Policy*. Nor for that matter does the Commission get into the various arguments by the various parties regarding their interpretation of the *Transmission Development Policy*.

18 Section 5(a) in *Electric Utilities Act* 2003 refers to the Market Surveillance Administrator, while that reference does not appear in *Electric Utilities Act* 2011.

35. The *Electric Utilities Act* establishes the ISO in Section 7(1).[19] Section 16 of the *Electric Utilities Act* sets out the ISO's code of conduct by stating that:

> The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.

36. In AUC Decision 2011-226,[20] Commission Member Yahya conducted an extensive analysis of the *Electric Utilities Act*, the *Transmission Regulation*, and the legislative history of the *Electric Utilities Act*. The conclusion in that concurrence, and the conclusion that the Commission adopts in this decision, is that all market participants, the AESO, and the AUC alike must conduct themselves with economic efficiency as their guiding value, especially when it comes to the generation market, in order to comply with the legislative mandate of the *Electric Utilities Act*.

37. With respect to Milner's Complaint situated, timewise, in 2005, the standard of review through which the Commission reviews complaints against AESO rules can be found in Section 25 of the *Electric Utilities Act* 2003. Section 25(1) provides that "[a]ny person may make a written complaint to the Board about" an ISO rule, an ISO fee, or an ISO order. The Board, and now the Commission hearing matters arising from that time period, can do many things. It can dismiss the complaint (Section 25(6)(c)), direct the AESO to reimburse a market participant for any fees paid to the AESO (Section 25(6)(d)), or "confirm, change or revoke the fee or order" after examining the justness and reasonableness of the ISO fee or order (Section 25(6)(a)).

38. Finally, and most relevant to this proceeding, the Board, or AUC, may, according to Section 25(6)(b):

> order the Independent System Operator 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 this Act or the regulations[.]

39. The test, therefore, for what ISO rules survive scrutiny and, in effect, the standard of review by which the Commission must evaluate the Line Loss Rule that Milner complains about is whether the Line Loss Rule is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations."

40. Were the Commission evaluating a complaint regarding the Line Loss Rule after January 1, 2008, the standard of review, which is still the standard of review today in Section 20.4(3) of *Electric Utilities Act* 2011, would be the following. The Commission would have to evaluate whether the rule complained about did not comply with certain Commission rules, not applicable in this proceeding, was technically deficient, did not support "the fair, efficient and openly competitive operation of the market", or was not in the public interest.

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[19] The ISO currently operates under the trade name AESO.

[20] Decision 2011-226, Alberta Electric System Operator – Objections to ISO Rule Section 502.1 Wind Aggregated Generating Facilities Technical Requirements, Application Nos. 1606448, 1606482, 1606483, Proceeding ID No. 787, May 31, 2011, pages 32 to 41.

41. This standard of review is slightly broader than the earlier one, because it now makes economic efficiency one of the standards that govern AESO rules. Indeed, as stated in the concurrence of Commission Member Yahya:

> It is, therefore, abundantly clear that the lens through which any complaint against proposed ISO rules, when fairness is the grounds [*sic*] of the objection, must be an economic one, and specifically those relating to market efficiency. For that matter, any objection grounded on any of the four criteria, namely fairness, efficiency, openness, or competitiveness must be viewed through the economics of efficiency.[21]

42. The Commission notes that this efficiency requirement has existed in the *Electric Utilities Act* since its modern inception, and efficiency was repeatedly discussed in the legislature as one of the key goals of the *Electric Utilities Act*.[22]

43. Among the responsibilities that Section 17(e) of both *Electric Utilities Act* 2003 and *Electric Utilities Act* 2011 give to the AESO is developing a methodology to recover line losses. The *Transmission Regulation*, however, is where more detailed requirements are spelled out.

4.2 The Transmission Regulation

44. Section 19(1) of the *Transmission Regulation* 2004 is titled "Transmission system loss factors". Section 19(1)(a) requires the AESO to make rules that, among other things:

> reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses[.]

45. Section 19(1)(c) further requires the AESO to:

> 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[.]

46. Finally, Section 19(1)(e) instructs the AESO to:

> subject to Section 21, provide[] a means through the application of a calibration factor to adjust the amounts paid by the application of the loss factor described in clause (c) so that the owners of generating units pay the actual transmission line losses or receive a credit for overpayment.

47. Having established the rules, the AESO is then required by Section 19(2) to determine loss factors. These loss factors "must apply for a period of at least one year but not more than 5 years" (Section 19(2)(a)). They must also ensure 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" (Section 19(2)(d)). Finally, the "loss factors associated with a charge must not exceed 2 times the average transmission system loss factor" (Section 19(2)(f(i))), while the "loss factors associated with a credit must not exceed one times the average transmission system loss factor" (Section 19(2)(f(ii))).

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21 Ibid., paragraph 186, page 37.
22 Decision 2011-226, paragraph 180 to 184, pages 34 to 37.

48. In the current version, the *Transmission Regulation* 2010, Section 31 addresses the recovery of transmission system losses. It reiterates the AESO's responsibility to make rules that "reasonably recover the cost of transmission line losses" (Section 31(1)(a)) "for each generating unit" (Section 31(1)(a)(i)) "based on their respective locations and their respective contributions, if at all, to transmission line losses". In terms of designing the loss factors, the rules are similar with the exception that after January 1, 2009, "loss factors associated with a charge must not exceed 12%" (Section 31(2)(g)(i)), while "loss factors associated with a credit must not exceed 12%" (Section 31(2)(g)(ii)).

49. Interestingly, the line loss factors are applied on a lumpy or discrete basis. In other words, they are applied on an annual basis calculated once a year or for a period not exceeding five years. This is in contrast to the wholesale energy market where prices are calculated on a real-time basis.[23] In order to facilitate the analysis, it is useful to understand the context from which these two divergent systems emerged.

4.3 Background context of the line loss lumpy factors

50. With the introduction of competitive markets and restructuring in l995, it was an open question whether and to what extent pricing and market signals would be utilized in transmission planning and tariff development. At various times Alberta has addressed incorporating price signals into the transmission tariff to optimize transmission and generation investments.

51. Prior to restructuring, Alberta had a policy that eliminated rate differentiation between customers in rural and urban areas of the province. This was accomplished through a pooling of all costs and the establishment of a postage stamp pricing principle for transmission service. Postage stamp transmission pricing means that transmission rates paid by owners of distribution companies (and their customers) are the same regardless of location on the transmission system. It is called postage stamp because the cost is the same regardless of receipt or delivery points on the system, just as the cost of postage stamps is the same to mail a letter anywhere within the country.

52. Through a series of decisions, culminating in EUB Decision 2002-099,[24] the issue of transmission pricing signals to generators was debated at length. The Board evaluated three approaches to provide locational signals including locational marginal pricing, a reliability / commercial classification system and zonal tariffs. In the end, the Board directed that a system of zonal charges be implemented to provide a location market signal to generators. This would have meant that load customers would pay an extra charge depending on the location of the generator in real-time.

53. The decision was ultimately overturned by amending the *Electric Utilities Act* to state in Section 30(3)(a) that the AESO's rates "shall not be different for owners of electric distribution systems, customers who are industrial systems … as a result of the location of those systems or persons on the transmission system". This enshrined the postage stamp principle for load customers in the *Electric Utilities Act* where it remains to this day, and customers do not pay based on where they locate within the province. As such, with respect to the AESO tariff,

[23] The offers and bids are done on a minute by minute basis and the price is calculated hourly averaging the prior sixty minutes.

[24] EUB Decision 2002-099: Transmission Administrator Congestion Management Principles, Application No. 1248859, November 5, 2002.

location is not to be taken into account, and hence with respect to marginal pricing, which is the basis of the energy wholesale market, location does not factor into these real-time operations. Customers are therefore not to be charged for the locational choices of the generators.

54. On the other hand, with the postage stamp approach to marginal pricing, the *Transmission Regulation* directed the AESO to calculate line loss factors in a lumpy and time-wise discrete manner. Prior to 2006, they were set every five years and after that every year. This contrast also informs the Commission in evaluating the AESO's line loss rules.

55. Prior to 2005, the methodology for calculating loss factors was determined through a tariff application, which was approved by the Board, with the last one being EUB Decision 2000-1.[25] The *Transmission Regulation* 2004 moved the process for determining the methodology for calculating line losses from the tariff to the ISO rules, while the cost of line losses continued to be collected under the ISO tariff. Practically, this meant that the Board did not have to approve the line loss factors and charges every few years, but now the AESO could enact a rule that is stable subject to only an objection by a market participant and an adverse decision by the AUC. The EUB in Decision 2005-096 even stated that "parties are free to file a complaint with the Board if they are not satisfied with the AESO's proposal for the setting of loss factors".[26]

5 Commission's analysis of the AESO's Line Loss Rule

56. The test for the Commission when analyzing the AESO's Line Loss Rule is whether the rule is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations." This test forms the standard of review by which the Commission will evaluate the AESO's Line Loss Rule. The legislature, when articulating this test, was not using it for the first time; rather, the words in this phrase have a well defined jurisprudence in regulatory law. When evaluating the Line Loss Rule, the Commission will, therefore, apply these terms to the rule in light of the jurisprudential history associated with them in Alberta and elsewhere.

57. The language of the test that forms the standard of review is the longstanding language that has always been the standard by which utility rates must be designed. In the *Electric Utilities Act*, when the Commission looks to a regulated utility's tariffs and rates, Section 121(2) requires that "[w]hen considering whether to approve a tariff application the Commission must ensure that (a) the tariff is just and reasonable," and that "(b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law." Indeed, this language permeates the *Electric Utilities Act* in all its versions since its enactment.

58. For that matter, when the original *Public Utilities Act* was passed in Alberta in 1915, Section 29 ordered that "No public utility ... shall--(a) make, impose or exact any unjust or unreasonable**,** unjustly discriminatory or unduly preferential individual or joint rate".[27] A search

25 EUB Decision 2000-1: ESBI Alberta Ltd. 1999-2000 General Rate Application Phase 1 and Phase 2, Application No. 990005, File Nos. 1803-1 and 1803-3, February 2, 2000.

26 EUB Decision 2005-096: AESO 2005 General Tariff Application – Phase I and Phase II, Application No. 1363012, August 28, 2005, page 13.

27 In Re *Public Utilities Act City of Edmonton v. Northern Alberta Natural Gas Development Co*., [1919] A.J. No. 123, paragraph 59.

of the case-law in Canada, the United Kingdom and the United States all reveal injunctions against discriminatory prices in their laws of rate design.[28]

59. Just recently, the Commission faced the issue of rate design in AUC Decision 2009-065 (Ventures decision)[29] where it examined the disparity in rates that a company with a dominant position was charging two customers. The Commission concluded that the rates were discriminatory, and ordered an appropriate remedy.

60. The law governing such rates applied to railways long before electric and gas utilities existed. The United States Supreme Court explained the reasoning behind the prohibition against discrimination for regulated railways under the *Interstate Commerce Act*:

> Prior to the enactment of the … 'Interstate Commerce Act,' railway traffic in this country was regulated by the principles of the common law applicable to common carriers, which demanded little more than that they should carry for all persons who applied, in the order in which the goods were delivered at the particular station, and that their charges for transportation should be reasonable. It was even doubted whether they were bound to make the same charge to all persons for the same service,… though the weight of authority in this country was in favor of an equality of charge to all persons for similar services. ….
>
> The principal objects of the interstate commerce act were to secure just and reasonable charges for transportation; to prohibit unjust discriminations in the rendition of like services under similar circumstances and conditions; to prevent undue or unreasonable preferences to persons, corporations, or localities; to inhibit greater compensation for a shorter than for a longer distance over the same line; and to abolish combinations for the pooling of freights.[30]

61. Indeed the Supreme Court went on to cite the British Lord Justice Blackburn in *Railway Co. v. Sutton*, L. R. 4 H. L. 226, 239:

> When it is sought to show that the charge is extortionate, as being contrary to the statutable obligation to charge equally, it is immaterial whether the charge is reasonable or not; it is enough to show that the company carried for some other person or class of persons at a lower charge during the period throughout which the party complaining was charged more under the like circumstances.

62. The Commission, therefore, is cognizant of the need for the loss factors in the AESO's line loss rule to not only be reasonable as applied to individual generators, but that they must not be discriminatory between similarly situated generators.

63. In the current proceeding, the AESO stands in the shoes of a regulated utility. It submits its tariffs to the Commission for approval under the same principles that govern all other utilities. Its line loss rules are evaluated under a standard of review in *Transmission Regulation* 2004 that matches the test for its tariff design.

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[28] See e.g. *Maritime Electric Co. v. General Dairies Ltd.*, [1937] 1 D.L.R. 609 (P.C.); *Chicago Housing Authority v. Illinois Commerce Commission*, 20 Ill. 2d 37 (1960); Willie A. Grieve and Stanford L. Levin, "Common Carriers, Public Utilities and Competition", 5 Industrial and Corporate Change 993 (1996).

[29] Decision 2009-065: TransCanada Pipeline Ventures Ltd. and Suncor Energy Inc. – Application to Have the Ventures Pipeline (Oil Sands Pipeline) Regulated Under the Provisions of the *Gas Utilities Act* Section 24 of the *Gas Utilities Act* – Investigation, Application No. 1568110, Proceeding ID. 27, May 20, 2009 upheld on appeal in TransCanada Pipeline Ventures Ltd. v. Alberta (Utilities Commission), 2010 ABCA 96.

[30] *Interstate Commerce Commission v. Baltimore & O.R. Co.*, 145 U.S. 263 at 275.

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.[31] 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."[32]

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."[33] The Board then concluded that "cost causation therefore remains the primary consideration when evaluating a rate design proposal."[34]

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."[35]

68. With this background understanding of the standard of review, the Commission analyzes the line loss rule.

5.1 The line loss rule's legislative and regulatory requirements

69. Section 19(1)(a) of the *Transmission Regulation* states that the AESO must make rules to:

> reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses;

70. In assessing the compliance of the line loss rule with Section 19(1)(a), the Commission considered each of the different concepts found in this section individually and also in light of the overall legislative framework. First, the rule must reasonably recover the cost of transmission

[31] EUB Decision 2005-096: AESO 2005 General Tariff Application – Phase I and Phase II, Application No. 1363012, August 28, 2005; EUB Decision 2007-106: AESO 2007 General Tariff Application, Application No. 1485517, December 21, 2007; Decision 2010-606: AESO 2010 ISO Tariff, Application No. 1605961, December 22, 2010.
[32] Decision 2007-106, page 13.
[33] Ibid, page 14.
[34] Ibid.
[35] Ibid.

line losses. This means that not only must the AESO recover the losses, but it should do so in a reasonable manner. A reasonable manner goes to both the reasoning behind the rule enacted as well as the outcome of the rule. Reasonableness is a term long known in the law. The reasonable person standard has long been the gold standard of conduct in the common law. It speaks to the conduct by which people are expected to comport themselves with. In the law of torts, the question for whether certain behavior is reasonable, is what would the reasonable person do? In the law of contracts, when evaluating the meaning of a contract, the question is what would a reasonable person understand when reading the contract? The reasonableness of the recovery can only be assessed in the context of what must be recovered and the factors that must be taken into account when designing a recovery mechanism.

71. Second, the AESO must recover these losses based on the location and contribution of each generating unit, if at all, to losses. The recovery, therefore, must be tied to location and contribution. Interestingly, location is always mentioned before contribution throughout the relevant portions of the *Transmission Regulation*. While this may not necessarily suggest a superior status, or even a first among equals status, for location over contribution, it says that location is no less valued a factor than contribution when calculating losses.

72. As such, any rule established must account for location within the parameters of the rest of regulation and legislation.

73. Recovery of contribution is also important. To understand what recovery means, Section 19(2)(d) is instructive. It states that any loss factors upon which credits or charges are to be based must be "representative of the impact on average system losses". The Commission notes that there was little disagreement over the term 'average system losses' among the various parties. Additionally, Section 19(1)(b) of *Transmission Regulation* 2004 refers to determining transmission line losses for a specified period and the average transmission system loss factor for that specified period. Section 19(1)(d) refers to an annual determination of the difference between anticipated and actual transmission line losses. Section 19(2)(a) states that loss factors must apply for at least one year and not more than five years. Section 19(2)(d) then states that loss factors must be representative of the impact on average system losses. Finally, Section 19(2)(f) states that loss factors for a charge must not exceed two times average system loss factor and loss factors for a credit must not exceed one times the average system loss factor.

74. The Commission, therefore, finds that average system losses refers to total annual injections minus total annual withdrawals divided by total annual injections. That is to say, average system losses for a year is found by first calculating the difference between the amount of energy that is received onto the transmission system from the generator points of metering during a year and the amount of energy that is delivered from the transmission system to the bulk metering points during the same time period. That difference is then divided by energy received onto the transmission system during the same year to result in average system losses for the year.

75. Given these various provisions of *Transmission Regulation* 2004, the Commission can now determine the proper method for assessing loss factors.

5.2 MLF/2 does not comply with Section 19 of Transmission Regulation 2004

76. The concept of MLF and MLF/2 were explained above in sections 2 and 3. Essentially, a generating unit is charged at the end of the year, on a forecast basis, a price related to half the marginal loss its last unit of generation created for all its units generated.

77. The departure point for evaluating the current AESO line loss methodology is the question of whether the use of a marginal measurement is appropriate for recovery not based on real-time, but discrete and lumpy time periods. To answer this, the Commission is mindful of three considerations. First, the Commission notes that only generators are to pay for their locational choices. Second, loss factors are to be assessed on a discrete time basis (one to five years, but not real-time). Finally, a loss factor must be related to the generator's contribution to the average losses in the system (on an annualized basis as applied by AESO).

78. The Commission concludes that given these considerations, loss factors must also be lumpy in nature. In other words, were charges for line losses based on real-time then real-time tools for assessing the losses would be appropriate. Since the *Transmission Regulation* limits the collection of losses to one number on an annual basis, the tools for measuring this factor therefore must be tailored for such lumpy time periods and the lumpy nature of the power being produced.

79. To illustrate this, consider the initial water example. Suppose the individual who adds water to or takes water out of the reservoir is being charged on a real-time basis. If the individual was charged or credited by each litre of water taken out or emptied into the reservoir, then the individual could assess how much to put in or take out. For example, suppose the charges were $1/litre (or 50 cents under a MLF/2). Then, as the first litre is poured in, the individual would receive one dollar. If the individual poured in another ten litres, one litre at a time, he would then receive one dollar each time the extra litre was poured in. Now suppose, he decides to take out one litre of water. At that point, he would be charged one dollar for the one litre taken out. This is what a marginal costing approach would look like.

80. Now, however, consider if the charges could only be done at the end of the year, or at the end of a discrete time period during which various units of water were added or taken out. So, returning to the water example, suppose now the individual added a hundred litres and then took out one litre. It would make no sense to charge the individual one dollar per litre for the hundred and one litres (or 50 cents per litre if the cashier was charging MLF/2). It would, indeed, be absurd and unjust. Rather, what would make sense would be to look at the incremental contribution to the reservoir, or one hundred minus one litre for a net total of ninety nine litres added in. Then a price of one dollar times ninety nine would be the credit the individual receives. If the inhabitants wished to reasonably recover the cost of the water, it would make sense that the net total addition or subtraction from the reservoir be the basis upon which the charges or credits be assessed, or an incremental approach.

81. The Commission finds that, a reasonable person, if asked about the choice between an incremental approach and the marginal approach would agree that a reasonable way to recover the costs of the water would be the incremental approach when the recovery is to be done on a lumpy or discrete time basis.

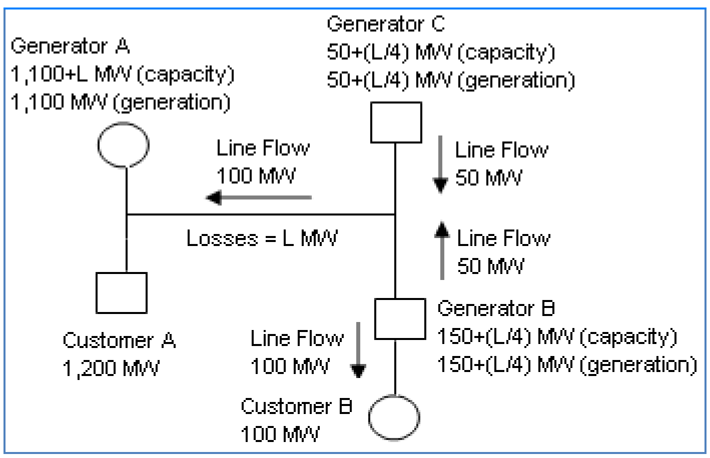
82. For line losses, the analysis is the same. Using the example developed above, suppose Generator B decides to service Customer B (as in Figure 3). Generator B would be lowering line losses to the system by 10,000*a*. That is the contribution to the average system losses. It takes into account location, because it rewards the generator that located close to load. Now if Generator B generates an extra 50 MW to send back to Customer A, Generator B will have lowered losses by 10,000*a* but added 2,500*a*. This means that its contribution to the average system losses is a net reduction of 7,500*a*. Under an incremental approach, Generator B would

receive a credit of 7,500*a*. Under a MLF approach or MLF/2 approach, Generator B will be charged for all the loss increasing units generated at a rate proportional to 2,500*a*.

83. This rule not only fails to measure the contribution of Generator B to the line losses, it also sends the wrong message regarding location. Instead of rewarding Generator B for locating close to Customer B, the marginal approach penalizes the generator for locating next to load. Even if Generator B only produced 100 MW to service Customer B resulting in an incremental gain of 10,000*a* to the system, the MLF (and MLF/2) would be zero. This would mean that Generator B is not even being rewarded for lowering the losses, in this example, to zero. The marginal approach sends no locational signal whatsoever to Generator B in this scenario. If anything, Generator B, when deciding how much to generate, has more of an incentive to under-generate in this situation. If Generator B only produced 50 MW, it would lower losses by 2,500*a* but its MLF (and MLF/2) would be negative. It would receive a credit, but the credit gets lower and lower the more Generator B produces.

84. In fact, suppose another generator, Generator C, had located in another location the same length away from Customer A as Generator B and that is connected to the line between Generator B and Customer A, but that only serves Customer A. This can be seen in Figure 6 below.

Figure 6. Simple example of Generators A, B and C and Customers A and B



85. Suppose it was sending 50 MW towards Customer A (and none to Customer B) due to extra demand by Customer A, instead of Generator B. Finally, suppose it also generated losses according to $L = aP^2$. Then Generator C would be charged, under a MLF or MLF/2, losses proportional to 2,500*a*, but would have increased losses by 2,500*a*. Hence, under a MLF or MLF/2 system, a loss saver such as Generator B who lowers losses by 7,500*a* gets charged in proportion to 2,500*a* while another unit that increases losses by 2,500*a* gets charged the same amount.

86. The MLF or MLF/2 approach rewards those who lower losses for only some of the loss savings, then gives no reward when the losses have been diminished, and then penalizes them if they generate slightly more. It neither captures the generator's contribution nor rewards it for its locational choice. A marginal loss factor (MLF) or MLF/2, therefore, does not comply with the *Transmission Regulation*, because an instantaneous picture of losses at a level does not measure the contribution of individual generators to the average system losses, let alone accounting for

their location. Additionally, Section 19(2)(d) which states that loss factors must be representative of the impact on average system losses is not satisfied.

87. The marginal approach not only fails to comply with the *Transmission Regulation*, it also violates the cost-causation principles. It unjustly discriminates against generators who are lowering losses by charging them while unduly enriching those causing the losses with the proceeds. There may be a perfectly good reason for each charge individually, but when the two categories of generators stand side by side, the Commission is mindful of Lord Blackburn's admonition that "it is immaterial whether the charge is reasonable or not; it is enough to show that the company carried for some other person or class of persons at a lower charge during the period throughout which the party complaining was charged more under the like circumstances."

88. Here, the situation is worse. Not only are the two generators being discriminated against based on their contribution to losses, the loss saver is being charged while the loss causer is being charged the same amount (as in the example above). This stands the principle of cost-causation on its head. Indeed, when Commission Member Lyttle questioned the witnesses for the Generator Group about whether it would be acceptable to charge or credit above what the generators were contributing to system losses, Mr. Levson of the Generator Group described such a methodology as discriminatory and stated that:[36]

> A. MR. LEVSON: Yeah. My view is with kind of my cost of service -- cost causation background is that the preferable thing to do is to figure out what costs are being caused by each of the generators and price accordingly and then let them take that into account in their decision-making, along with all of the other factors, and that that overall process will get us the most efficient result.
>
> As soon as you introduce a cross-subsidy of some kind, like your mechanism or some other mechanism, you're introducing the likelihood that it's going to cause a perverse result.
>
> So unless there's a really good reason to depart from cost causation, like a policy reason or directive or something like that, that's why I've always felt that's the best way to go.

89. The Commission agrees with Mr. Levson. Any system that amplifies or mutes signals is by its very nature contradictory to basic cost-causation principles and leads to inefficient economic signals due the creation of cross-subsidies. These cross-subsidies, as the Board had remarked previously, are at odds with the concepts of economic efficiency. They are also at odds with the principles underlying rate design.

90. To see the cross-subsidy effect, consider the immediate prior example. Suppose that Generator B was generating 150 MW, 100 MW to service Customer B and 50 MW for Customer A. Suppose Generator C locates close to but not at Generator B, and after Generator B has become operational, and has the same loss causation profile as Generator B in that $L = aP^2$. Suppose also that Generator C generates 50 MW to serve Customer A. Total losses are now 10,000a, where Generator B has caused 2,500a for its last 50 MW and Generator C has caused 7,500a for its next 50 MW. Under an incremental approach, Generator B would receive a credit

[36] Transcript, October 22, 2011, Volume 4, pages 929-30.

of 7,500*a* reflecting the lowering of 10,000*a* in losses plus the 2,500*a* from its last 50 MW, while Generator C (at least in the first year) would be charged for its extra 7,500*a* in losses created.

91. Under a marginal approach, however, and specifically MLF/2, Generator B will be charged 5,000*a* and Generator C will also be charged 5,000*a*. This is because they are treated as if they are at the same location and hence are assessed half the marginal loss of their combined output of 100MW. Indeed, mathematically charging them each 5,000*a* yields the correct total loss of 10,000*a*. The total losses, however, are unevenly distributed. Generator B which has lowered losses by 7,500*a* is now being charged 5,000*a* while Generator C which increased losses by 7,500*a* is only being charged 5,000*a*. The result is the cross-subsidy that cost-causation and the principles of rate design warn against.[37]

92. While this incremental approach advantages older plants at the expense of newer ones, creating a vintaging issue, the Commission does not see this as an issue for an ILF approach. If anything, this sends the proper signal to generators that take advantage of locations that need generation. It rewards the early arrivers. The lumpy nature of the *Transmission Regulation* makes it clear that the Government of Alberta envisioned that generators would have at least one year and up to five years to recoup their investments based on their locational decisions. The Commission will have some suggestions for the AESO (in Section 7 of this decision) regarding this issue.

93. Accurate cost allocations are required to give efficient pricing signals. Efficient pricing signals underpin generators location decisions. Efficient generation where costs are allocated accurately reduces marginal costs to generators and those savings are ultimately passed on to consumers. Accurate location pricing also has the added benefit of signaling generation investment that may ultimately reduce the cost of the overall system, thus satisfying the objectives of the *Electric Utilities Act* and the *Transmission Regulation*. The public interest is upheld most easily by maintaining a methodology that most accurately represents the principles of cost-causation, and the ultimate efficiency savings that will result.

5.3 The AESO's line loss rule is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations."

94. The line loss rule is inconsistent with the *Transmission Regulation*. This should be sufficient to find against the line loss rule. That being said, it is also unjust and unreasonable. It is unjust because it punishes loss savers and does not properly charge loss creators for their losses. As such it is unduly preferential, because it prefers those generators in the deep system over those in the remote areas of the province, even though those in the remote areas are the ones saving the system losses at the periphery.

95. It is unjustly discriminatory as it violates all the principles of rate design that would normally be observed in a regular rate or tariff proceeding. As discussed earlier, line losses were recovered through the AESO's tariff. This meant that the AESO had to subject its line loss methodology to scrutiny periodically. Then the *Transmission Regulation* was amended to make the determination of a loss factor methodology through an ISO rules process rather than an ISO tariff process. This meant that the AESO no longer had to have periodic scrutiny of its

37 See analysis of the Generator Group's evidence below in paragraph 101.

methodology, and that only if a market participant challenged the rule would the Commission examine it.

96. That did not, however, mean that the principles the AESO had to use changed. The fact that the standard of review through which the AUC would analyze complaints about ISO rules until 2007 was the same test used when designing rate structures meant that those principles stayed intact. Hence, the unduly discriminatory test still applies for the AESO's line loss rule during the 2006-2008 period.

97. In rate design, the principle of cost-causation requires that there be no undue discrimination between ratepayers in the same class. Those who cause high costs should pay for the high costs and those whose costs are lower should pay less. Translated into the line loss rule, this would mean that, at the very least, loss causers should pay while loss savers should receive a credit. When those who lower line losses are actually charged while those causing losses are charged much less than their contribution, this not only is unduly discriminatory, but unjust.

98. ENMAX's argument explains the unjustness of the rule through a visual representation in a chart.[38] ENMAX used the data provided by the AESO for all the generators to conduct a linear regression with the dependant variable being actual losses and the independent variable the actual power injections in and out of the various generators. The model then generated predicted losses based on the actual data. ENMAX called these predicted values ordinary least squares loss factors (OLF). Notwithstanding data and econometric limitations that ENMAX openly admitted, the Commission accepts the ENMAX analysis for the purpose it was introduced, namely to evaluate the accuracy of the AESO's line loss methodology.

99. On the right hand side of ENMAX's graph all but one of the ten highest loss creators have MLF/2 that are less, and sometimes by a substantial amount below the 95 per cent confidence estimate of the OLF analysis which estimates the actual loss factors. These subsidies are being substantially funded by the generators represented on the left hand side of the chart or the loss reducers by the area above which the MLF/2 lies above the OLF. ATCO also illustrates a further unjustly discriminatory aspect of this cross-subsidy and states "[t]his example illustrates the general case which is that the degree to which loss reducers are disadvantaged relative to loss causers is directly proportional to their benefit to the system"[39] Not only is the cross-subsidy unjust, but the unjustness is amplified the more a loss reducer helps the system, and the corollary holds for the loss causers.

100. The unfairness to loss savers was also detailed extensively by ATCO and Milner in their examples and evidence. What has not been as equally detailed is the effect of the added unjustness where generators locate in a generation rich area. This effect was best represented by the Generator Group in its evidence.[40] Although their evidence was meant to highlight some inadequacies within an ILF methodology, it showed that losses for all six generating units in aggregate to be six per cent of the total output. From the figure, no matter which generator was assessed last, the first MW of production from that generator would incur losses substantially above zero per cent. This is because there are already losses being incurred on the line, not unlike Generator C in the example developed in paragraph 84 above.

[38] Exhibit 0296.01, ENMAX Argument, November 30, 2011, page 28, paragraph 90.
[39] Exhibit 0133.01, Evidence of ATCO Power, April 14, 2011, page 15, paragraph 61.
[40] Exhibit 0204.01, Evidence of the Generator Group, June 9, 2011, Figure 6, page 17.

101. MLF/2 where the losses from the first MW generated are above zero further distorts the location signal because the MLF/2 could be lower than the initial system losses. If a generator in the deep system had an MLF of eight per cent and MLF/2 of four per cent and its contribution to losses was above four per cent for its first MW then the MLF/2 would not be representative of any minimum point of generation.[41] In other words, because generators that locate close to each other get charged the same MLF/2 for their combined output, they could actually be charged an amount lower than their average in aggregate. The subsidy will therefore be coming from those generators outside the deep system who lower losses but are charged nonetheless.[42]

102. If loss factors were assessed in real-time, the Commission notes, MLF would be a perfectly acceptable method of pricing losses. If, for example, initially Generator A was serving Customer B, then it would be facing a MLF of 200*a*, which would signal to it that it is causing losses. Generator B, if it turned on and started to serve Customer B would face a MLF of -200*a* for the first unit of power produced. This would signal that it should continue to generate power to serve Customer B. Indeed, it would continue to produce power until the MLF plus the marginal cost of producing the power was equal to the marginal revenue it would receive from the energy market. All generators would be receiving real-time signals. But that is not the law in Alberta. Rather, the law requires pricing on an annual (or up to five years) basis.

103. Indeed the evidence presented by the Generator Group through their two experts, Dr. Roach and Mr. Musco, showed that a form of marginal pricing was used by American system operators, but all of the examples presented involved real-time or close to real-time pricing. The Commission accepts Dr. Roach's evidence that all six of the major U.S. Regional Transmission Organizations "will soon use marginal cost methods, not incremental cost methods".[43] However, the Commission understands that the basic framework for electricity exchange in Alberta and the evolution of that methodology as detailed above is different from these other markets.

104. In addition to the examples cited by Milner itself in its evidence, the Commission places great weight on the ENMAX's empirical analysis. Notwithstanding Dr. Roach's cursory dismissal of the analysis,[44] there was no proper rebuttal of the empirical evidence analysis presented. The Commission accepts the analysis detailed by ENMAX, as representative of many of the examples used by both the Generator Group and others of what is occurring in reality within the Alberta Interconnected Electric System (AIES).

[41] See Exhibit 0175.01, Milner (MacCormack) Evidence, June 9, 2011, figure 6, page 61. This situation would be represented by the mirror image of this situation with the MLF/2 as an outlier below the curve's actual loss generation.

[42] Deep system is a technical term that was used throughout the proceeding. Here, the Commission uses it to refer to those generators who are located in the heart of the system and whose generating units collectively are causing net positive average system losses.

[43] Exhibit 0204.01, Generator Group Evidence, July 28, 2011, page 9.

[44] Dr. Roach dismissed the evidence because it was not properly specified. The Commission rejects this on three grounds. The first is that even if the functional form was improperly specified, Dr. Roach could have generated an econometric model that would predict the bias in ENMAX's regressions. No such analysis was proffered. Second, even an incorrect functional form (i.e. square instead of linear) does not negate the strength nor the qualitative strength of the various descriptive statistics and other parameters. A straight line can also be drawn thorough various observations that are squared in nature. Third, the Commission notes that not only does ENMAX's evidence acknowledge the non-linear nature of the evidence (see ENMAX Evidence, Exhibit 0176.01 and ENMAX Argument, Exhibit 296.01 pages 30 to 32), the point of the evidence was not to draw a relationship between the output and line losses. Rather, the empirical work was meant to measure the degree of congruence between the measured line losses and estimates used to charge or credit the various generators.

105. In addition to the theoretic examples used throughout this decision, the empirical evidence presented by ENMAX and the other groups, the Commission conducted its own empirical analysis to satisfy itself that ENMAX's analysis was qualitatively correct. The Commission looked at the raw data provided by the AESO.[45]

106. For the year 2006, the Commission looked at those generators that had a negative ILF, but that were assessed a positive charge based on MLF/2. The Commission found that 24.5 per cent of generators that should have received a credit under ILF received a charge under MLF/2. The average overcharge to these generators was in the amount of 3.3 per cent. Furthermore, 23 per cent of those generators with positive ILFs were charged less than their ILF factors under the MLF/2 by about 2.8 per cent. This analysis did not even take into account those generators that had a negative ILF of 13.73 per cent, but was credited only 0.57 per cent based on MLF/2.

107. This casual empiricism reinforces Milner's, ATCO's and ENMAX's claim that loss reducers are subsidizing loss creators. In fact, for 2007, the Commission found that 24.5 per cent of those generators that had negative ILFs were charged a positive MLF/2 charge. In other words, in 2007, 24.5 per cent of those generators lowering system losses were being charged and not receiving a credit. This number does not even account for those who had a large ILF but received a substantially lower credit. Of those 24.5 per cent of overcharged generators, the average overcharge was 4.5 per cent. The Commission then looked at generators that had a positive ILF, but whose MLF/2 was lower. In other words, these were generators who were adding more losses than what they were being charged. The Commission found that 32 per cent of those generators with positive ILFs were undercharged by 2.2 per cent less than their contribution to losses. Finally, in 2008, 24.5 per cent of those generators that had negative ILFs were charged a positive amount with an average overcharge of 4.1 per cent, while 28 per cent of those generators with positive ILFs whose MLF/2 were lower than their ILF were undercharged by 1.8 per cent.

108. The Line Loss Rule in 19(2)(d) mandates 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. An MLF methodology gives more consideration to losses from the last MW of production from a generator while giving less consideration to losses from previous MWs of production. The MLF is used to approximate what the impact this generators effect would be on average system losses. ILF does not make this assumption. ILF does not treat the first loss as zero, but uses what the generator actually caused. ILF does not need an approximation to estimate an outcome.

109. The outcome from ILF is closer to what the generator's actual impact on average system losses is. Only when a generator starts generating zero losses with its first MW of production will the MLF approximation be valid and equal to the ILF result. Generators rarely, if ever, have zero losses from their first MW of generation. With MLF their contribution to average system losses are not necessarily based on their actual losses. With MLF when a generator's first unit of power generated results in credits to the system, they are under-recovering their share towards average system losses, when their first power produced results in losses above zero to the system, they are undercharged for their share of average system losses. Generators that start producing losses below zero from their first unit of power are subsidizing generators that start

[45] Exhibit 0140.03, Normalized Loss Factors Spreadsheet, April 27, 2011.

producing losses above zero from their first unit of power. The greater the loss either way from zero for the first unit of power produced, the greater the price discrimination that results.

110. The Commission finds that the Line Loss Rule is unduly preferential and unjustly discriminatory and favours loss causers at the expense of loss savers. The Commission finds that the AESO's assertion "that the 50% area load adjustment methodology (ie dividing the marginal loss factors by 2) is the mathematically correct way to determine the impact of generators on average system losses" is not supportable by the analysis of the evidentiary facts. The theoretic and empirical analysis shows that a MLF/2 does not measure the contribution nor reward the locational choice of generators to system losses. Not only does this methodology not comply with the *Transmission Regulation*, it fails the standard of review that the Commission must use to assess ISO rules.[46]

111. An MLF/2 methodology gives more consideration to the last MW of production from a generator while giving less consideration to previous MWs of production. The evidence during the hearing was that the only time that MLF/2 would be the same as ILF was when the MLF of the first contribution from the generator was zero and this rarely occurs.[47] The MLF/2 methodology is, therefore, unrepresentative of the generators' contribution to average system losses as the last loss from the last MW generated bears no direct relationship to the first loss or ultimately the average loss. This is in direct contravention of Section 19(2)(d) of the *Transmission Regulation*.

112. Additionally, the Commission notes that the line loss rule violates the spirit of the *Electric Utilities Act*. The AESO is commanded "to promote a fair, efficient and openly competitive market for electricity." As such, when designing a rule for collecting line losses, the rule must be economically efficient.

113. As discussed earlier, were loss factors assessed in real-time, MLF would have been the proper loss factor methodology. But in a discrete time methodology, the ILF method is clearly economically efficient.[48] It takes location into account and holds loss causers accountable and rewards loss reducers, and is more representative of the contribution to average system losses.

114. Charging everybody the system average is computationally the easiest answer and has no locational distortion effects. Yet, no one from the Generator Group accepted that suggestion, which suggests that all market participants want a system that can be more discriminating in rewarding loss causers and savers.

115. During the hearing, there was much discussion and argument concerning the usage of a MLF recovery mechanism as opposed to MLF/2. These concerns were that MLF over-recovers losses, by about twice the amount that MLF/2 does. Also, the mechanisms needed to redistribute or shift those monies between generators, and yet keep the signals as accurate as possible were not so obvious.

116. The Commission finds that the discussion of these issues misplaced. First of all, the Commission finds that an ILF methodology, and not the MLF or MLF/2, is what complies with

[46] Exhibit 0297.02, ATCO Argument, November 30, 2011.
[47] Exhibit 0175.01, Milner (MacCormack) Evidence, June 9, 2011, page 7.
[48] Dr. Stoft provided an elegant mathematical proof of this in Exhibit 0282, Milner (Stoft) Undertaking, October 31, 2011, which the Commission accepts as a proper economic proof of the efficiency of ILF.

the *Transmission Regulation* and legislative framework discussed earlier regarding lumpy recovery of line losses. ILF collects total losses far better than an MLF or MLF/2 methodology, and so questions regarding shifting are less important. As stated previously, MLF/2 is the same as ILF when the first MW contributed is zero. Some starting values will be above zero and some below, but the Commission finds that the total collected will be closer to the total collected under MLF/2 than MLF. The Commission, however, finds that the shift mechanism to deal with an MLF versus an MLF/2 methodology is better supported by the economic principles, especially if the shift factor is a lump sum refund at the end of the year.

117. Finally, the AESO intended to employ a different loss factor methodology to imports, exports and opportunity service loads in its letter to stakeholders dated September 13, 2005.[49] It advised that it would use an incremental loss factor approach which the AESO called a "distributed load option". These users were required to pay for their total losses their transactions caused as opposed to average losses.

118. The Commission questions the reasonableness of the different proposed methodologies. An ILF or "distributed load option" could not be better for one set of users but a poorer choice for generators. If the MLF/2 charge were satisfactory for generators it would have made sense to propose it for importers and exporters. Interestingly, as Milner's evidence points out, the AESO uses the ILF methodology when it brings needs applications.[50] This further brings the question of the reasonableness of the MLF/2 methodology.

119. To recap, the Commission finds that the MLF/2 methodology is not the economically efficient method when the time-period for recovery of line losses is lumpy as mandated in the *Transmission Regulation*. The Commission finds that the current MLF/2 methodology is unable to properly account for location and contribution. The Commission finds that the MLF/2 is unjust and unjustly discriminatory. Given all of these reasons, the Commission finds that Milner's complaint against the line loss rule is valid.

5.4 The AESO's line loss rule is not in the public interest and does not support a fair, efficient and openly competitive market

120. Because the line loss rule is not economically efficient, under the new standard of review, the Commission finds that Milner's complaint would also be valid, were it complaining about the line loss rule post 2008.

6 The Commission's degree of deference to the AESO's line loss rule

121. The AESO, the Generator Group and the dissent engage in a discussion regarding the degree of deference that should be owed to the AESO. The Commission has three points to make on this issue.

[49] Exhibit 0175.01, Milner (MacCormack) Evidence, June 9, 2011, pages 41 to 44.
[50] Ibid.

6.1 The standard of review is specified in the Electric Utilities Act

122. A deferential standard was argued to be the proper standard based on the language of the Supreme Court of Canada's pronouncement in *Dunsmuir*.[51] Although the courts have refined their various standards of review over the years, the Commission has always had its standard of review clearly specified in the *Electric Utilities Act*. The standard of review, as specified in the legislation governing both the AUC and the AESO, is either that the AESO rule is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations" prior to 2009 or that, among others, the AESO rule is not in the public interest or does not support a fair, efficient and openly competitive market.

123. The Commission has engaged its analysis under these two lenses. It is satisfied that the complaint regarding the line loss rule is valid under either of the two standards.

6.2 It is not clear that the Dunsmuir standard applies here

124. Dunsmuir deference refers to the deference courts pay to specialized administrative agencies when evaluating the reasonableness of their adjudications or rule-making.

125. Here, the legislature of Alberta chose to have appeals of ISO rules through the complaint process brought before the AUC and not a court. As such, the legislation has the rules of one agency being appealed to another specialized administrative agency.

126. Indeed if all that was required was deference to a fair process, there would be no specified standard of review. A review of Alberta's Hansard indicates that when the *Electric Utilities Act* was being debated back in 2003, recourse to the EUB (now the AUC) was contemplated for when the AESO was "felt to be heavy handed or leaning too hard on some individual or some person or a corporation", which would ensure that the AESO, even though the AESO was "an independent body", "also has someone to answer to."[52] Had the legislature wished that the AESO be accorded the deference that courts accord administrative agencies, it would have provided for judicial review or statutory appeals. This is not the case. Rather, a complaint process is specified with a clear standard of review in the legislation. Again, this is what the Commission used when evaluating the line loss rules.

127. The Commission can review the substantive as well as procedural aspects of an ISO rule. Indeed, under the current standard of review, the legislature has both procedural grounds for review of an ISO rule as well as three substantive grounds clearly spelt out. Under the current Section 20.4(3)(a) of the *Electric Utilities Act*, a market participant objecting to an ISO rule has to prove that the AESO when making its rule "did not comply with Commission rules". Hence, this ground for appeal is procedural. The remaining three grounds for appeal found in sections 20(4)(b), (c), and (d) relate to whether the rule is "technically deficient", "does not support the fair, efficient and openly competitive operation of the market", or "is not in the public interest." These are the substantive grounds for appeal.

[51] *Dunsmuir v. New Brunswick* [2008] 1 SCR 190.
[52] Alberta Hansard, March 19, 2003, page 629.

6.3 Even if the AUC should afford the AESO some deference, the rule fails the Dunsmuir test of reasonableness

128. If the Commission were to evaluate the AESO rule under such a standard, it would look to the passage of the rule, the consultation process, and its responses to the comments it received.

129. First, the AESO gave instructions to Teshmont Consultants LP (Teshmont) regarding what criteria to use when selecting a proper loss factor methodology. These instructions contained five criteria, which included instructions regarding a shift factor, the range of loss factors, seasonal volatility, swing bus independence and what to do with generators whose raw loss factors exceed the limits specified in the *Transmission Regulation* 2004.

130. Absent from these criteria was anything to do with location, most importantly, and economic efficiency. Indeed, in its initial written evidence, the AESO asserted that

> The AESO understands the purpose of the relevant sections of the TReg is to allocate to and recover the total cost of system losses from generators in a reasonable manner. Insofar as losses and loss factors are concerned, the TReg is not about an economic exercise, nor does the TReg create an economic problem. The AESO's Line Loss Rule substantially complies with the requirements of the TReg, and fairly allocates the cost of transmission losses as directed.[53]

131. The Commission notes that the courts have little deference to administrative agencies when they fail to take into account key legal requirements. In *Oakwood Development Ltd. v. St. François Xavier,*[54] Madam Justice Wilson said that "the failure of an administrative decision-maker to take into account a highly relevant consideration is just as erroneous as the improper importation of an extraneous consideration."[55] The AESO relied on the Teshmont report to determine which loss factor methodology to use, the Teshmont report did not take into account the factor of locational signals, and locational signals are a highly relevant consideration that were not taken into consideration by the AESO. Similarly, in *Rodrigues v Ontario (Workplace Safety & Insurance Appeals Tribunal)* the Court of Appeal of Alberta noted that "[w]here there is highly significant and relevant evidence that goes to the very matter a tribunal must decide, there must be some indication that the decision maker considered it."[56] The AESO, through Teshmont, did not take location, let alone economic efficiency, into account.

132. In its reasons adopting the Line Loss Rule, the Commission notes that its response to Milner, ATCO, and ENMAX did not adequately address the concerns raised by these parties. Indeed, the Commission was not sure if the AESO fully appreciated their concerns regarding the loss causers and savers not being properly charged. The list of participants who had issues with the line loss rule also impacts this analysis. The Commission looked at the submissions of Luscar, Calpine, IPCAA, Canadian Hydro, and ATCO to the AESO, who were all registered in the initial proceeding of the Milner complaint. The Commission sometimes felt that the parties were like ships passing in the night, with each talking past each other. This shows in the lack of proper analysis in response to the parties' comments.[57] Indeed, the Generator Group which tried

[53] Exhibit 0205.01, AESO Evidence, June 28, 2011, page 2, paragraph 3.
[54] *Oakwood Development Ltd. v. St. François Xavier* [1985] 2 SCR 164.
[55] Ibid. at paragraph 69.
[56] *Rodrigues v Ontario (Workplace Safety & Insurance Appeals Tribunal)* [2008] ONCA 719, paragraph 67.
[57] Throughout the various AESO responses to the parties' positions in Exhibit 0133.03, ATCO Evidence, April 14, 2011, including Attachment 4: *AESO 2006 Transmission Loss Factor Methodology Decision Document*.

to defend the AESO's methodology also revealed that they did not understand the nature of the complaint during the oral portion of the proceeding.[58]

133. Finally, given that the actual outcome is fundamentally unjust, it cannot survive a *Dunsmuir* reasonableness standard. Indeed the Court of Appeal of Alberta recently overturned a decision by the Board that had allowed ATCO Gas to collect 85 per cent of moneys it was owed by customers going back six years.[59] These moneys were improperly accounted for in ATCO Gas' deferred gas account (DGA). The Board cited many reasons for why ATCO Gas should not recover their arrears and then only gave one cursory reason why they should be allowed to collect. Two justices on the court held that this was unreasonable and remanded it to the AUC for further analysis. Justice Cote, writing for himself, not only found the Board's reasons unreasonable, but he would have held the outcome unreasonable and awarded ATCO Gas no collection whatsoever.

134. The Commission finds itself in a similar situation reviewing the AESO's line loss rule. Even if it were to owe *Dunsmuir* deference, which the Commission does not believe it does, the Commission would find the lack of proper reasons in the factors that it directed Teshmont to look into and the unjust outcome of the rule do not save the rule.

135. As such, even if the AESO's rule and rule-making process were evaluated under *Dunsmuir,* no deference would be owed here. The Commission notes that, in the past, where the AESO has achieved the economically efficient outcome in a fair process, the Commission has upheld impugned rules.[60]

7 The Commission's views on location and the length of line loss periods

136. As the Commission has upheld Milner's complaint, prior to discussing the remedy and the process for the next phase of this proceeding, the Commission considers it instructive for all the participants in this proceeding to discuss some desired features in a line loss rule.

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*.

138. Line losses have averaged approximately $180 million dollars per year over the last six years,[61] a substantial amount that generators pay, yet those costs are ultimately borne by consumers. Not only do consumers ultimately foot this bill, line loss computations and future losses are a major input into the location decisions for new transmission lines. Consequently, the size and cost allocation of line losses are critically important to many aspects of the industry.

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58 Exhibit 0297.02, ATCO Argument, November 30, 2011, pages 25 to 27.

59 *Calgary (City) v. Alberta (Energy and Utilities Board),* 2010 ABCA 132.

60 Decision 2011-226: AESO – Objection to ISO Rule Section 502.1 Wind Aggregated Generating Facilities Technical Requirements, May 31, 2011.

61 For the annual amount and value of transmission line losses in Alberta from 2005 to 2010 see Table 1 in the dissent to this decision.

139. 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 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.

140. Section 19(2)(a) of the *Transmission Regulation* gives the AESO discretion to apply loss factors for a period of at least one year, but not more than five years. The AESO has applied line loss factors for the minimum period of one year and the justification for doing so was to promote greater responsiveness to changes occurring in a quickly evolving system.

141. The evidence indicated that the previous rule mechanism created non-accurate line losses because losses were fixed for five years and system changes, transmission line upgrades, new generation and retiring generation, as well as the generally increasing load levels, would effect those fixed percentage allocations.

142. The Commission agrees with the desire for accuracy within any line loss rule and this has led to our finding that the current methodology concerning MLF/2 is a poor estimator of a generator's contribution to average system losses, however one has to look to what the line loss was intended to accomplish when examining all aspects of the rule. This consideration should not be lost in the consultation on the new line loss rule.

143. The AESO has the discretion to apply line losses for a longer period and it has chosen the minimum period that the rule allows. The line loss rule primarily must send accurate signals to incent efficient dispatch and optimize system efficiency's to minimize the overall cost to ratepayers and create a level efficient playing field between generators. But generation siting decisions are lumpy and long-term in nature, and the legislators seem to have recognized that within the current *Transmission Regulation* by allowing these loss factors to remain in place for up to five years.

144. The Commission finds that the one-year period has some advantages over a five-year period; however there are aspects of a five-year line loss rule that if it could be incorporated could benefit long-term siting efficiency in the market.

145. Currently, with a one-year line loss rule, if an opportunity to invest in an energy deficient zone is presented and a generator invests in that area then losses to the entire system are reduced, and that benefit of increased efficiency is shared by all consumers. However, if another generator locates there then the advantage to the first located generator is lost. The Commission appreciates the principle that competition should ultimately rule, but knowing the first mover advantage is easily lost, how can one incent generation into an area?

146. IPCAA, who represents a large section of consumers in Alberta, is interested in ensuring that "Albertans are receiving an optimized delivered price of energy". Also from their argument they "would like to see an ability to capture that value for at least 5 years".[62]

[62] Exhibit 0301.01, IPCAA Letter, November 30, 2011, page 2.

147. As discussed above, a one-year or even a five-year signal will be lumpy in nature. Legislators, however, have kept signals of at least one year so any system will have to be able to encompass that incremental versus marginal aspect within the *Transmission Regulation*. Ultimately this is why the Commission has found that the MLF/2 methodology is not compliant with the *Transmission Regulation*; because when examining that rule through the "lens" of the ILF methodology, the rule is unjust, unreasonable, unduly preferential and arbitrarily or unjustly discriminatory.

148. ENMAX's 'fundamental flaw' in the Line Loss Rule is that "a Line Loss Rule that provides both an ineffective long-term locational signal and an inefficient real-time dispatch signal", details the clashing components within the rule.[63]

149. By seeking a greater responsiveness in the rule to changes and being as close to real-time as the rule permits the rule tries to be as close to marginal pricing as it can, but in reality it is an incremental rule and should be designed with that concept in mind.

150. The regulation permits losses based on one year, but also up to five years as preferred by IPCAA. The Commission urges the market to consider that the rule should be weighted somehow with the current year's line loss and some rolling average of previous years. This method would preserve the current accuracy that is permitted with a one-year estimator, however, it still can capture the long-term siting incentives that a line loss rule can be crafted to accomplish. Some have argued that this would create issues around vintaging, however, if the legislators had intended this not to be examined, the five-year optionality could have been removed, it was not.

151. The first locator generator will receive some location incentive for building and this will ultimately be exposed to competition over time, however, this incentive will persist for longer than one year as it is presently crafted. The second generator will not receive the benefit and, therefore, a longer-term siting signal will be created.

152. During the consultation the market might still agree to have the rule for determining loss factors persist for only a one-year period, however, with the latitude currently within the legislation it is an area that could be examined with a view to a more robustly incented location signal.

8 Relief sought, findings and remedy

153. Milner has requested that the Commission find that the AESO's Line Loss Rule fails to comply with the *Transmission Regulation* and the *Electric Utilities Act*. It made several other motions regarding Dr. Roach's evidence and the onus of proof.

154. The Commission finds that the complainant, i.e. Milner, always has the onus and burden of proof. The Commission finds that Milner has met its onus and burden.

155. Regarding Dr. Roach's testimony, the Commission accepts it and accords it the appropriate weight that allowed it to reach its conclusions.

[63] Exhibit 0296.01, ENMAX Argument, November 30, 2011, page 2, paragraph 9.

156. Finally, and most importantly, the Commission finds that the complaint regarding the line loss rule is valid for the period 2006 to 2008 when the rule complained about was in effect.

157. At this stage, it is not clear whether Milner is also complaining about the rule as it is in effect today. None of the parties made an issue of this in any meaningful way. Therefore, the Commission request that the parties address the proper timeframe for Milner's complaint.

158. The Commission seeks submissions from the parties regarding the proper timeframe of Milner's complaint. At this stage, to be clear the Commission has found in Milner's favour except in regards to the TMR component of their complaint as detailed in AUC Decision 2012-105 for the periods 2006, 2007 and 2008.

159. The Commission has not made any determination related to the options available to it under Section 25(6) of *Electric Utilities Act* 2003 as to the revoking or changing of the rule and any potential claims for compensation. There are many avenues available to parties with regards to legislation and following are some areas that the Commission will seek submissions on.

160. First, Milner's remedy is revoking the rule for the 2006 to 2008 period. This means that the old rule could be in place for that period. Milner would probably be refunded an amount by the AESO that could be argued in the second phase of this hearing. The Commission notes its two-year limitation period, and the effect is that only Milner would be able to collect a refund. The AESO may wish to accept this remedy for that time period as only Milner would be entitled to a claim and it would not upset any accounting among the generators.

161. In addition to the first option, Milner could argue that it had always been complaining about the rule. It would have to present evidence from its pleadings that would allow the Commission to treat its complaint as a continuous process since its original complaint. It may argue something akin to a constructive complaint. Regardless, if Milner can successfully convince the Commission that their complaint has always encompassed the present rules, then the Commission would have to decide what to do with the present rule. The Commission has made findings that the present rule (which does not differ much from the older rule other than the limits on credits and charges) also does not succeed under the new standard of review. The Commission seeks submissions from all the parties, including the AESO on how best to proceed.

162. Third, Milner may argue that they did not complain about the present rule but that they wish to now. In this case, for regulatory expedience, the Commission most likely would open a new proceeding, but roll the record from this proceeding into that one. The Commission would then invite parties to submit only updates in evidence since this proceeding. The Commission has used this abbreviated process in other settings such as its most recent Generic Cost of Capital proceeding.[64] Again, the Commission seeks submission from the parties on this option.

163. There may be other options, and the Commission is open to hearing from the parties on these matters.

164. At this stage, the Commission has not pronounced on which remedy it shall proceed under. Under the *Electric Utilities Act* 2003, it could revoke the rule, change the rule or send it back to the AESO for further consultation. The AESO may wish to concede that the rule is

[64] AUC Decision 2011-474, December 8, 2011, Proceeding ID No. 833, Application No. 1606549.

revoked for the 2006 to 2008 period, and propose a consultation methodology that complies with the Commission findings and its discussion in Section 7 above in this decision for the 2009 and onwards rule.

165. The Commission will leave the argument for remedy and which of the three options (or any other) for the next phase of the proceeding.

9 TMR

166. Milner complained about the role TMR plays in computing line losses. The Commission rejects this complaint for the reasons outlined in the companion decision, AUC Decision 2012-105.

10 Order

167. Milner's complaint is valid. The Commission will proceed to the next phase of the proceeding. A letter outlining the process for this next phase will be issued shortly.

Dated on April 16, 2012.

The Alberta Utilities Commission

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Moin A. Yahya
Commission Member

11 Dissenting reasons of Commission Member Tudor Beattie

168. I have had the opportunity to consider the decision of the majority in this proceeding and I respectfully disagree with the conclusion that Milner's Complaint is valid. Therefore, I write separately to express my reasons for rejecting Milner's Complaint.

11.1 History of this proceeding

169. On August 17, 2005, Milner filed a complaint under sections 25 and 26 of *Electric Utilities Act* 2003 against the Line Loss Rule developed by the AESO, alleging that the rule did not comply with the requirements of *Transmission Regulation* 2004 and that it was otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory.

170. The Board refused to investigate or hold a hearing, and by EUB Decision 2005-150 summarily dismissed Milner's Complaint on the ground that it was not warranted. Milner appealed to the Court of Appeal of Alberta. By Memorandum of Judgment, *Milner Power Inc. v. Alberta* (Energy and Utilities Board), 2010 ABCA 236, the court vacated the Board's decision and remitted the matter to the Commission to continue to further investigate or hold a hearing to determine whether there was a contravention of Section 19 of *Transmission Regulation* 2004 as alleged.

11.1.1 Basic introduction to transmission line losses

171. Transmission line losses, at the most basic level, are the difference between the amount of energy that is received on to the transmission system from the generator points of metering and the amount of energy that is delivered from the transmission system to the bulk metering points for eventual consumption. The energy is typically lost through heating in the transmission line and grid transformers, primarily due to the resistance of the line material and internal transformer wiring. Losses on a transmission line vary as a function of the length of the line. Therefore, keeping everything else constant, with equivalent power flow, total losses on a 100 kilometre transmission line will be approximately ten times the total losses on an identical transmission line that is only 10 kilometres in length.[65] Also, losses on a transmission line vary as the square of the power flow on the line. Keeping all other factors constant, a transmission line with a power flow of 100 MW will incur four times the amount of losses as the same line with a power flow of 50 MW.

172. Losses are inevitable on any transmission system where energy flows across transmission lines, and the amount or value of those losses can sometimes be considerable. The amount and value[66] of losses in Alberta for the past several years are as follows:[67]

[65] This is a first-order approximation of the differences in losses on a 100 kilometre transmission line versus a 10 kilometre transmission line.

[66] Note that the value of losses is not simply the amount of losses multiplied by the average pool price. This is because the amount of losses varies constantly with changing system conditions. As submitted by the AESO in Exhibit 205.01, page 2, the value of those losses is found by multiplying the amount of losses in any hour by the hourly pool price, and then summing those values throughout an entire year.

[67] Sourced online February 15, 2012, from the AESO annual reports from 2005 to 2010 at www.aeso.ca.

Table 1: Amount and value of transmission line losses in Alberta

Year	Amount of line losses (gigawatt-hour (GWh))	Value of line losses (Millions)
2010	2,696	$130.6
2009	2,513	$123.1
2008	2,650	$220.6
2007	2,870	$183.8
2006	2,900	$231.9
2005	2,900	$200.8

173. In Alberta, the overall cost of transmission line losses is generally borne by generators.[68] Thus, loss factors are a method of distributing the cost of line losses amongst all generators. Some generators receive a credit (for reducing transmission line losses) and other generators pay a charge (for increasing transmission line losses), depending on their location on the transmission system. However, line losses are also important to consumers because in the end it is consumers, including industrial, commercial and residential consumers, that pay for electricity generated in Alberta, whether that electricity is used to serve load or to cover transmission line losses.

174. Much of the evidence in this proceeding concerned specific circumstances in the northwest area of Alberta. The northwest area is large in geographic terms, approximately one third of the area of Alberta, but small in terms of electric load. There are load centres at Grand Prairie, Valley View, Fort Nelson, B.C.[69] and Rainbow Lake, and the distances between these centres are considerable. Fort Nelson, B.C., is more than 200 kilometres west of Rainbow Lake, which is more than 500 kilometres north of Grand Prairie.[70] The AIES in the northwest consists largely of transmission lines that are 240-kilovolts (kV) or smaller. As noted by the AESO, the Rainbow Lake area is historically sensitive to load and generation changes.[71]

11.2 Regulatory framework

11.2.1 Legislative scheme

175. The *Milner* Court of Appeal of Alberta judgment described the Milner Complaint as a right to question a rule or fee of the ISO[72] and directed determination whether there was a contravention of Section 19 of the *Transmission Regulation* 2004 as alleged by Milner. I therefore consider the Milner Complaint as a right accruing and with a potential remedy under the *Electric Utilities Act* 2003 as it stood on August 17, 2005, when the complaint was filed.[73]

[68] Per Section 22 of the *Transmission Regulation* 2004.
[69] As indicated on the BC Hydro website (www.bchydro.com sourced February 15, 2012), Fort Nelson is not connected to the BC Hydro grid, but is connected to the AIES via a transmission line. BC Hydro operates a gas-fired generating station in Fort Nelson and has a supply agreement with the AESO to provide backup and reliability in supply.
[70] Exhibit 0303.01, AESO Reply Argument, December 22, 2011, pages 9 to 10.
[71] Exhibit 0175.01, Milner (MacCormack) Evidence, June 9, 2011, page 28.
[72] Exhibit 0133.03, ATCO Evidence, Attachment 6, *Milner Power Inc. v. Alberta (Energy and Utilities Board)*, 2010 ABCA 236, paragraph 28.
[73] Gustavson Drilling (1964) v. The Minister of National Revenue, [1977] 1 SCR 271 at page 5.

Consequently, the legislation as it read at that date is applicable to and governs the determination of the Milner Complaint, and is unaffected by its later amendment effective as of January 1, 2008.

176. The purposes of *Electric Utilities Act* 2003 are set out at Section 5 and include:

> (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….
>
> (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;
>
> ….

177. The ISO was established under Section 7(1) of the *Electric Utilities Act* 2003 and operates under the trade name AESO. The *Electric Utilities Act* 2003 also specifies the ISO's powers and duties to operate the electric power system and to be the sole provider of system access service on the transmission system. Section 16 of the *Electric Utilities Act* 2003 provides:

> The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.

178. Milner's Complaint in August 2005 was made to the Board. The Commission is now charged under the *Alberta Utilities Commission Act* with responsibility for electric utilities regulation and, by virtue of Section 80, the continued conduct of administrative proceedings pending against the Board.

179. The *Transmission Regulation* 2004 was made under the *Electric Utilities Act* 2003 and came into force on August 12, 2004. It imposed further specific responsibilities and duties on the ISO with respect to transmission loss factors. Section 19 of the *Transmission Regulation* 2004 is attached in its entirety in Appendix 3.

180. Section 25 of the *Electric Utilities Act* 2003 provided a method of complaint to a market participant:

> **25(1)** Any person may make a written complaint to the Board about
>
> (a) an ISO rule,
> (b) an ISO fee, or
> (c) an ISO order.
> ...

181. If the Board hears the complaint, Section 25(6) empowered the Board to take a number of actions including:

> **25(6)** If the Board decides to hear the complaint, the Board may, by written decision giving reasons,
>
> …
>
> (b) order the Independent System Operator 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 this Act or the regulations;
>
> (c) dismiss the complaint;
>
> …

11.2.2 2003 Transmission Development Policy

182. One issue in this proceeding raised by Milner's Complaint was what consideration should the Commission give to the Alberta Government's 2003 policy paper *Transmission Development: The Right Path for Alberta – A Policy Paper* (*Transmission Development Policy*)[74] in interpreting the requirements of and assessing the Line Loss Rule's compliance with the *Transmission Regulation* 2004. The *Transmission Development Policy* indicates that it was intended, at the time, to serve as a basis for the development of a regulation dealing with transmission, and Milner's president and CEO testified at the hearing that Milner assumed the *Transmission Development Policy* provided direction on how loss factors would be treated.[75]

183. Policy documents or extrinsic aids can assist in the legislative history of an enactment when interpreting legislation.[76] Legislative history materials can be used as indirect evidence of meaning or purpose, but not as direct evidence of the Legislature's intent. Extrinsic aids, such as policy documents, legislative debates, briefs and other materials, serve to clarify statutory provisions that are ambiguous or uncertain. The Supreme Court of Canada stated in *Morguard Properties Ltd. v. Winnipeg (City)*:

> It has, of course, been long settled that, in the interpretation of a statute […], the report of a commission of enquiry such as a Royal Commission may be used in order to expose and examine the mischief, evil or condition to which the Legislature was directing its attention. However, in the interpretation of a statute, the court, according to our judicial philosophy, may not draw upon such reports and commentaries, but must confine itself to an examination of the words employed by the Legislature in the statutory provision in question and the context of that provision within the statute.[77]

184. However, it appears clear that in the event of conflict between statements of intended policy found in the *Transmission Development Policy* and unambiguous legal requirements brought into force by the *Transmission Regulation* 2004, the provisions of the *Transmission Regulation* 2004 prevail.

185. In the *Transmission Development Policy*, the Department of Energy had stated that a regulation under the *Electric Utilities Act* 2003 would be prepared to implement the approved transmission policy. It is apparent that with respect to line losses there are significant differences

[74] Exhibit 133.03, ATCO Evidence, Attachment 7 - *Transmission Development Policy* of November 2003.
[75] Transcript Volume 1, pages 27 to 28.
[76] Sullivan, Ruth, *Sullivan and Driedger on the Construction of Statutes*, 4th ed. (Markham: Butterworths Canada Ltd., 2002) at page 20.
[77] *Morguard Properties Ltd. v. Winnipeg (City)* [1983] SCR 493.

between the policy as set forth in the *Transmission Development Policy* and the ensuing *Transmission Regulation* 2004, and there are certain aspects of the policy that did not find expression in the ensuing regulation. ENMAX provided a detailed and helpful comparison of the differences at paragraph 26 of its final argument dated November 30, 2011.[78] As ENMAX noted, no specific guidance was subsequently forthcoming explaining the reasons for the significant differences between the *Transmission Development Policy* and the relevant sections of the *Transmission Regulation* 2004. I accept ENMAX's assertion that the readily discernible focus of the *Transmission Development Policy* on sending locational signals is absent from the *Transmission Regulation* 2004 and that the *Transmission Regulation* 2004 includes inconsistent and conflicting requirements.

186. In the final analysis, I do not find the applicable provisions in the *Electric Utilities Act* 2003 or its regulations (such as the *Transmission Regulation* 2004) to be ambiguous or uncertain. Consequently, I do not need to draw upon the *Transmission Development Policy* for guidance or rely upon it to interpret the *Transmission Regulation* 2004 and determine whether or not the Line Loss Rule complies with the *Transmission Regulation* 2004. Rather, the challenge was determining what is reasonable in the context of reconciling conflicts and inconsistencies evident in the *Transmission Regulation* 2004 itself.

11.2.3 Statutory interpretation

187. As stated by the Court of Appeal of Alberta, at paragraph [32] of the Milner appeal judgment, the modern principle of statutory interpretation requires "the words of an Act be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament."[79] When interpreting the plain wording one must pay sufficient attention to the scheme of the act, its object and the intention of the legislature.[80]

188. As indicated in *Sullivan on the Construction of Statutes*,[81] 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 act, having regard to the language and purpose of the act in general and more particularly the language and purpose of the relevant enabling provisions.[82] This is consistent with Section 13 of the *Interpretation Act*[83] providing that interpretation provisions in an enactment apply to regulations made under an enactment.

189. A key issue in this proceeding is an assessment of what is "reasonable" in terms of the Line Loss Rule complying with the different and sometimes conflicting requirements imposed by the various instances of the mandatory "must" language used in sections 19(1) and 19(2) of the *Transmission Regulation* 2004. ENMAX argued, in effect, that the *Transmission Regulation* 2004 was consequently fundamentally flawed and that it is not possible for any line loss rule to comply with all aspects of the *Transmission Regulation*.[84] The modern principle of interpretation

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78 Exhibit 296.01, ENMAX Argument, November 30, 2011, pages 10 to 12, paragraph 26.
79 *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998]1 SCR 27, 154 DLR (4th) 193 at paragraph 21 quoting Driedger in *Construction of Statutes* (2nd ed.1983) at 87.
80 *Rizzo* at paragraph 23.
81 *Sullivan on the Construction of Statutes*, 5th edition, page 368.
82 *Bristol-Myers Squibb Co. v. Canada (Attorney General)* [2005] 1 SCR 533.
83 *Interpretation Act*, S.A. 2000, Chapter I-8.
84 Exhibit 0296.01, ENMAX Argument, November 30, 2011, page 1, paragraph 5.

leads me to a different conclusion in this instance. The "must" language of Section 19 should be construed in a manner that will enable the regulation to be read as a harmonious whole. I interpret this to mean that, to a reasonable extent, the AESO had to accommodate the other mandatory "must" requirements in Section 19 when fulfilling its duty to make a Line Loss Rule. This interpretation is reinforced by the fact that the requirement under Section 19(1)(a) is only to "reasonably recover the cost..." and that the ISO is directed to have only "regard" under Section 19(2) to the "must" requirements which follow.

190. In assessing and determining the reasonableness of the Line Loss Rule in terms of its overall compliance with the requirements of Section 19 of the *Transmission Regulation* 2004 I have been guided by the words provided by the Supreme Court of Canada about judging reasonableness in the *Dunsmuir v. New Brunswick* [2008] 1 SCR 190 decision:

> 47 …But it [reasonableness] is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law.

191. I recognize that this is not a judicial review of an administrative decision and, as explained in the Milner appeal judgment, deference should not be given to the ISO. I am persuaded however, that it is important to assess whether the Line Loss Rule under consideration falls within the range of possible, acceptable outcomes which are defensible and in overall compliance with Section 19 of *Transmission Regulation* 2004.

192. The AESO and the Generator Group argued that the extensiveness and transparency of the consultation process undertaken with stakeholders, and the ensuing consensus achieved regarding guiding principles appropriate to selecting a line loss rule methodology were relevant factors to consider in weighing whether or not the resulting Line Loss Rule was in compliance with the *Transmission Regulation* 2004 requirements. I do not find those considerations to be particularly helpful; rather attention and analysis should be focused directly upon whether the Line Loss Rule resulting from the consultation process, complied with Section 19 of the *Transmission Regulation* 2004. This is best determined by directly analyzing the features of the Line Loss Rule and assessing their adequacy in totality with all of the requirements of Section 19 of the *Transmission Regulation* 2004. In this analysis it is also relevant whether there were other sections of Section 19 to be adhered to over and above those which Milner alleges were contravened.

11.2.4 Scope of Commission authority

193. The Supreme Court of Canada made the following point regarding the jurisdiction of the Commission's predecessor in *ATCO Gas & Pipelines Ltd. v. Alberta* (Energy and Utilities Board) 2006 SCC 4:

> Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, Administrative Law in Canada, (3rd ed. 2001), at pp. 183-184).

Also see *Dunsmuir v. New Brunswick*[85] to the same effect. As indicated in the ATCO Gas and Pipelines Ltd. decision, this question of tribunal jurisdiction requires interpretation of the legislative framework by which the tribunal derives its powers and authority.

194. The source of the Commission's authority to deal with ISO rules such as the Line Loss Rule is the *Electric Utilities Act* 2003. From August 17, 2005, when Milner made its written complaint to the Board until the end of 2008, the applicable provision was Section 25(1) which allowed written complaint by any person about an ISO rule. The powers given to the Board to provide relief to the complainant are found in Section 25(2). They are preconditioned on the Board deciding to hear a complaint. If the Complaint is upheld the Board is empowered to 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 this act or the regulations, or dismiss the complaint.

195. Milner made a written complaint on August 17, 2005, about the proposed Line Loss Rule notice of which the AESO posted on its website on November 18, 2005, to become effective as of January 1, 2006.

196. On April 11, 2007, *Transmission Regulation* 2007 came into force, replacing the *Transmission Regulation* 2004. A new line loss rule (2009 Line Loss Rule) was developed considering the new *Transmission Regulation* 2007. On November 14, 2007, the ISO gave notice of its approval of the new 2009 Line Loss Rule to be effective as of January 1, 2009, and that the existing Line Loss Rule continued in effect until December 31, 2008. The significant fact for legal purposes of determining AUC jurisdiction as successor to the Board is that the existing Line Loss Rule was replaced and a new line loss rule made rather than by amendment of the existing rule. There is no evidence, and I consider it is factually correct, that Milner did not make a written complaint to the Board about the new 2009 Line Loss Rule.

197. The lack of a written complaint about the new 2009 Line Loss Rule may, to some, appear a mere legal technicality when features complained about by Milner in the 2006 Line Loss Rule continue to be reflected in the new 2009 Line Loss Rule. However, the Board's powers to give relief, under Section 25(2) of the *Electric Utilities Act* 2003 respecting an ISO rule, are clearly dependent upon the existence or making of a written complaint about the ISO rule to the Board, not the existence of common features for complaint as argued by Milner and ATCO. This complaint requirement in the statute promotes the achievement of commercial certainty as a significant number of market participants may be materially impacted by a challenge to an ISO rule. Market participants should be able to discern, by ascertaining whether a written complaint has been made to the Board, whether any particular rule is under challenge without having to speculate or interpret the intentions of other parties imputed from the existence of other written complaints. Having complained once already, it would not have been that difficult for Milner to make a complaint about the new rule.

198. Consequently, I conclude that the Commission's only statutory authority with respect to Milner's complaint is to deal with the Line Loss Rule in effect from 2006 through 2008.

[85] *Dunsmuir v. New Brunswick* [2008] SCC 9, paragraph 29.

11.3 Process related matters

11.3.1 Interlocutory motions

199. On April 26, 2011, TransCanada filed a motion[86] to strike, evidenced termed "Impugned Evidence" in the application. On August 15, 2011, Milner filed a motion[87] to strike portions of the evidence filed by the Generator Group and of Dr. Roach, who was proposed to testify as an expert witness for the Generator Group. Neither application was granted. The Commission deferred a final decision and heard any disputed evidence provisionally, subject to objections made, and considered the "Impugned Evidence" in the context of the totality of the evidence tendered at hearing and the arguments made by counsel regarding the evidence's proper evidentiary effect. These objections were made in various applications filed to exclude evidence prior to the hearing, argued at the hearing and reiterated in final arguments.

200. Section 20 of the *Alberta Utilities Commission Act* provides that the Commission is not bound in the conduct of its hearings by the rules concerning evidence that are applicable to judicial proceedings. The Commission may hear any evidence introduced that may be relevant, decide what evidence is relevant and what is not, decide what part of the evidence is to be accepted and what part rejected, weigh the evidence that it accepts and where there are conflicts in the evidence decide which evidence is more likely to be true, and come to reasonable conclusions based on such evidence. Its overriding duty is to observe the principles of procedural fairness. This requires listening to and acting fairly regarding all parties, and giving each party a fair opportunity to respond to and contradict adverse testimony or information presented at hearing.[88]

201. In considering the witnesses tendered at hearing as experts, I found each of them to be properly qualified as experts within their proposed area of expertise. It is apparent that the Line Loss Rule and the *Transmission Regulation* 2004 engage technical considerations including issues of electrical engineering, quantitative methods, economics and public utility regulatory policy.

202. The strict traditional requirements applicable to judicial proceedings for the admission of expert evidence are addressed in the *R. v. Rohan*[89] decision; however, in dealing with the Complaint, I find that all of the expert evidence heard was relevant to and assisted with understanding the competing aspects of the *Transmission Regulation* 2004 and the Line Loss Rule, and interpretation of this highly technical rule and regulation. The logic justifying receipt of expert evidence from an expert on provincial stumpage appraisal policies in *British Columbia (Minister of Forests and Range) v. British Columbia (Forest Appeals Commission)*[90] is equally applicable in the present proceeding, and all of the expert evidence tendered in this proceeding warranted consideration.

203. Milner argued that the independence of Dr. Roach had been successfully impeached during his cross-examination with the result that his testimony should be rejected or ignored. The

86 Exhibit 139.01, TransCanada Motion, April 26, 2011.
87 Exhibit 215.01, Milner Motion, August 15, 2011.
88 *Kane v. University of British Columbia* [1980] 1 SCR 1105 at 1112-13; *Mooring v. Canada (National Parole Board)* [1996] 1 SCR 75 and *Lavallee v. Alberta (Securities Commission)* 2009 ABQB 17, 2010 ABCA 235.
89 *R. v. Rohan* [1994] 2 SCR 9.
90 *British Columbia (Minister of Forests and Range) v. British Columbia (Forest Appeals Commission)* [2009] BCCA 354.

nature of his relationship with his clients was explored at length during questioning at hearing.[91] I find that Milner failed to establish his lack of independence. Dr. Roach did not display a lack of objectivity and responsiveness in giving his evidence. Objections to the admissibility of his testimony in these regards are therefore rejected and dismissed.

204. Each party was afforded sufficient advance disclosure of intended expert evidence, opportunity to seek other data relevant to it and explanations about it through information requests prior to the hearing, and reasonable opportunity at the hearing to question each expert who testified and to present its own evidence in reply.

11.3.2 Onus of proof

205. In correspondence prior to the hearing and again in final arguments, the issue was raised regarding which party bears the onus of proof respecting the Complaint. The concept is only relevant where sufficient essential evidence is lacking or where competing proof appears evenly balanced to the tribunal. In the latter case, onus of proof serves as the "tie – breaker."[92] There was no lack of proof or evenly balanced proof at the end of hearing evidence on any material issue and no need to resort to the onus of proof to determine the Complaint.

206. For future guidance, in the absence of a legislative direction such as was subsequently provided by Section 25(4.1) of the *Electric Utilities Act* 2003, the principle generally applicable in civil cases applies. The party who asserts a proposition bears the burden of proving its proposition on a balance of probabilities. Here, Milner is the party asserting that the Line Loss Rule contravenes Section 19 of the *Transmission Regulation* 2004, following *Snell v. Farrell*.[93] Given the ample ability of parties in AUC proceedings to determine information from other parties through information requests, it is not likely that the usual burden of proof will often need to be shifted to require a party with particular knowledge of facts or documents other than the applicant to prove such. However, that determination will be made on a case-by-case basis where this issue may arise as particular circumstances warrant.

11.4 Findings

207. In reaching the determinations contained within this dissent, I have considered all relevant materials comprising the record of this proceeding. Accordingly, references in this dissent to specific parts of the record are intended to assist the reader in understanding my reasoning relating to a particular matter and should not be taken as an indication that all relevant portions of the record with respect to that matter were not considered.

208. The Line Loss Rule uses a methodology called the Corrected R Matrix 50 per cent Area Load Adjustment Methodology to determine load flow based raw loss factors.[94] For ease of reference I will be referring to the methodology adopted in the Line Loss Rule as MLF/2.

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[91] Transcript Volume 3, beginning at page 745.
[92] See *Alberta Provincial Judges' Association v. Alberta* (1999), 177 DLR (4th) 418.
[93] *Snell v. Farrell*, [1990] 2 SCR 311, *Nand v. Board of Education Public School District No. 7 (1995)*, 157 A.R. 123 (CA).
[94] Exhibit 0133.03, ATCO Evidence, ISO Rule Appendix 7: *Transmission Loss Factor Methodology*, May 5, 2005, page 3.

11.4.1 Evidence presented during the hearing regarding MLF-shifted methodologies

209. In this proceeding there was considerable evidence and argument regarding comparisons between loss factors derived under the Line Loss Rule, being MLF/2, and loss factors derived by an MLF-shifted methodology. In my opinion, any MLF-shifted methodology would have to first meet the requirements of the *Transmission Regulation* 2004 in order to provide a useful comparison between MLF-shifted methodologies and the Line Loss Rule. In addition, given that MLF/2 and MLF-shifted are both MLF-based methodologies, when comparing different MLF-based methodologies there would have to be a material difference in the resulting loss factors in order to conclude that the Line Loss Rule, or MLF/2, is biased or mutes the locational signal in contravention of the *Transmission Regulation* 2004. Milner presented an example of loss factors derived by an MLF-shifted methodology.[95] However, Milner has not demonstrated in its example that if its MLF-shifted method were applied to all generators in the province that the loss factors would recover the total cost of losses or fall within the Section 19(2)(f) collar.

210. I am unable to find sufficient evidence in this proceeding that can be used to benchmark loss factors calculated under the Line Loss Rule with loss factors calculated under any other type of MLF methodology that meet the requirements of the *Transmission Regulation* 2004, including but not limited to: (a) Section 19(2)(c) in that loss factor charges and credit must result in the reasonable recovery of transmission line losses; and (b) Section 19(2)(f) in that loss factors must not be greater than two times average system losses or less than one times average system losses.

11.4.2 Evidence presented during the hearing regarding ILF methodologies

211. Milner provided considerable evidence to contrast the difference between an ILF methodology and the Line Loss Rule when considering the contribution or impact of a generator on transmission line losses. During the proceeding ATCO, ENMAX and the Generator Group discussed similar examples relating to a u-shaped curve for losses[96] which reflect an area of the transmission system with relatively remote load and a new generator considering whether to construct in proximity to the remote load.[97] Milner's evidence, particularly the scenarios in Exhibit 175.01 – Milner (MacCormack) Evidence, Appendix B, provides insight into Milner's understanding of the phrase *contribution to line losses*. In these scenarios it appears that Milner is ignoring the conditions in the deep system[98] and the impacts that changing conditions may have on these scenarios. These scenarios are for illustrative purposes only, and I will consider these examples without consideration of the impacts on the deep system. In Scenario 1 of Appendix B of Exhibit 175.01, at the end of a transmission line there is 100 MW of existing load and a generator is considering whether to build in proximity to that load. Milner explained that the first MW of production from any new generator reduces losses because it alleviates the need

95 Exhibit 0298.02, Milner Argument, November 30, 2011, page 55.

96 Exhibit 0133.01, ATCO Evidence, April 14, 2011, page 13, paragraph 52; Exhibit 0266.01, ENMAX Aid-to-Cross, October 17, 2011, pages 2 to 6; Exhibit 0295.02, Generator Group Argument, November 30, 2011, pages 25 to 29, paragraphs 79 to 87.

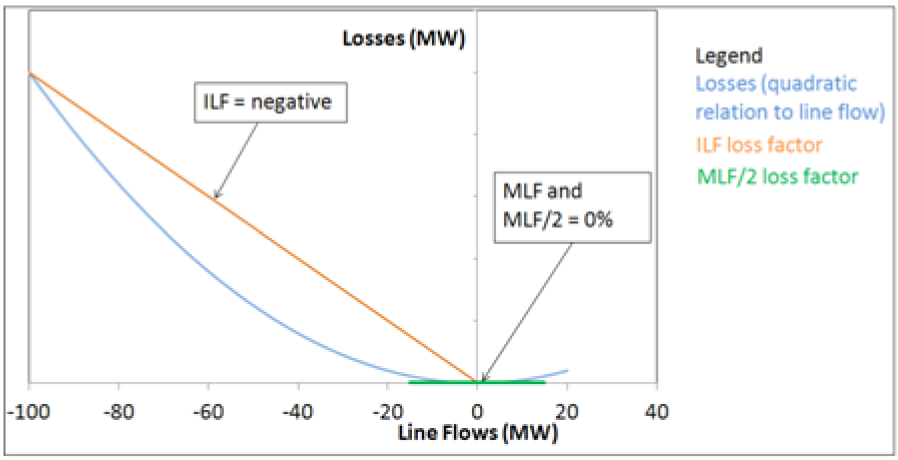
97 It is acknowledged in ATCO's submission that the calculation of loss factors may be influenced by the location of a swing bus and/or the size of the increment used in an ILF methodology, but these would be addressed in the course of any loss factor methodology and do not affect the principle of contribution to losses or impact on losses that is being discussed in these examples.

98 Milner (MacCormack) indicated that the deep system is treated as an infinite bus, where voltage and frequency remain constant, and is a proxy for the rest of the system which could be several thousand MW of generation and load. See Transcript, October 19, 2011, Volume 1, page 151.

for one MW of flow along the transmission line. Milner produced graphs to display transmission losses as a function of generator output.[99]

212. In Milner's Scenario 2 the new generator is 100 MW, which reduces losses along the particular transmission line to zero MW. Under an ILF methodology the generator would receive a negative loss factor, or credit, while under the Line Loss Rule the generator would receive a zero per cent loss factor (neither a credit nor a charge) as shown in the figure below.

Figure 7. ILF, MLF and MLF/2 loss factors in Milner's Scenario 2 with zero MW flowing along the transmission line

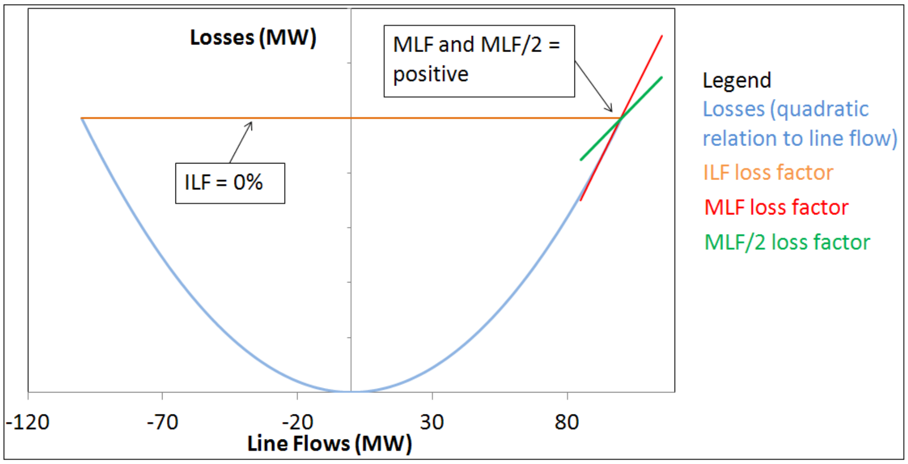


213. An incentive for the generator to locate in the proximity of the load would be to provide a credit for reducing losses, such as under an ILF methodology. Under the Line Loss Rule the generator would be assigned a zero per cent loss factor, and the generator would not pay anything for losses despite an output of 100 MW. While this zero per cent loss factor is not as strong an incentive as a credit, it is a signal that a new generator could locate in the proximity of the load and produce 100 MW without incurring any loss charges.[100] That is, with system average losses of five per cent in mind, the locational signal is clear in this example because a zero per cent loss factor on 100 MW of production is a signal for generation to locate in the proximity of load. However, this still does not clarify what is meant by contribution or impact on losses – for which Milner's Scenario 3 is helpful.

214. In Milner's Scenario 3 the new generator is 200 MW, which causes flow to reverse on the line. Milner submitted that because the generator is exactly twice the size of the local load, the first MW of production reduces system losses by an amount that is exactly equal to the amount that the last MW of production increases losses. Under an ILF methodology the generator would receive a zero per cent loss factor, while under the Line Loss Rule the generator would receive a positive loss factor, or charge, as shown in the figure below.

99 Exhibit 0175.01, Milner (MacCormack) Evidence, Appendix B, June 9, 2011, Scenarios 1 to 3.
100 In this scenario if the local load is 100 MW the generator could be any size up to 99 MW and all the methodologies in the scenario (ILF, MLF and MLF/2) would assign the generator a negative loss factor or credit.

Figure 8. ILF, MLF and MLF/2 loss factors in Milner's Scenario 3 with 100 MW flow (from left to right) along the transmission line



215. In Scenario 3, Milner submitted that a zero per cent loss factor is appropriate because "[o]n average this generator has no impact on system losses." However, one must assess the validity of this statement.

216. In Milner's Scenario 3, the first 100 MW from the generator would reduce flow along the particular transmission line (and thus reduce losses) and the last 100 MW from the generator would increase flow along the particular transmission line (and thus increase losses) to the point that overall transmission losses would be unchanged with or without the 200 MW generator in proximity to load. The Generator Group's argument[101] is helpful in interpreting Milner's statement that on average the 200 MW generator has no impact on system losses because, as the Generator Group stated, while total system losses have not changed, there has been a shift in the responsibility for or contribution to those total system losses. In Scenario 3, the 200 MW generator is impacting or contributing to the total system losses, and as such its loss factor should reflect this contribution. I consider that for this generator, which is producing 200 MW and is responsible for contributing some portion of overall system losses, a zero per cent loss factor (as calculated under Milner's ILF example) would not be based on its contribution to losses (per Section 19(1)(a) of the *Transmission Regulation* 2004) or representative of the impact on average system losses (per Section 19(2)(d)).

217. Further, in extending Milner's Scenario 3 by one MW so that the generator produces a total of 201 MW, under an ILF methodology the generator would still receive a loss factor of close to zero per cent when it is clear that the generator is directly contributing to losses and is actually *increasing* average system losses. I consider that a loss factor close to zero per cent for a generator that is increasing average system losses does not seem reasonable.

218. The ILF methodologies presented in this proceeding would contravene at least sections 19(1)(a) and 19(2)(d) of the *Transmission Regulation* 2004, and as such these ILF methodologies cannot be used as a benchmark or comparison when considering whether the Line Loss Rule contravenes the *Transmission Regulation* 2004 by not representing the contribution to or impact on transmission line losses by each generator.

[101] Exhibit 0295.02, Generator Group Argument, November 30, 2011, pages 25 to 29, paragraphs 79 to 87.

219. In light of the requirements of the *Transmission Regulation* 2004, including but not limited to sections 19(1)(a) and 19(2)(d), I find there is no evidence in this proceeding that the Line Loss Rule does not represent the contribution or impact of generators on system losses.

220. I also considered Milner's Scenarios 2 and 3 from the viewpoint of consumers. In Scenario 2, the total system losses are reduced, however under Milner's ILF methodology the 100 MW generator would receive the credit for reducing losses. From the consumer's perspective they would not see any direct benefit of the reduction in losses and would view the ILF method as a transfer from the deep system generators to the 100 MW generator. In Scenario 3, the total system losses are unchanged and under Milner's ILF methodology the 200 MW generator would receive neither a charge nor a credit. From the consumer's perspective they would not see any direct benefit because total system losses are not changed.

11.4.3 Evidence presented during the hearing by ENMAX

221. ENMAX submitted extensive evidence of a possible bias against loss reducers in favour of loss causers. However, in determining loss factors under other methodologies the ENMAX evidence does not go far enough in considering the requirements of the *Transmission Regulation* 2004, including but not limited to Section 19(2)(c) and Section 19(2)(f).

222. ENMAX submitted its OLF values indicate a bias in the Line Loss Rule, however the ENMAX evidence does not give any indication that its OLF values would recover the total cost of losses or fit within the collar. Of note, the table of OLF values in Exhibit 176.02 includes loss factors in the order of +211 per cent and -315 per cent, which do not appear to reasonably represent the contribution to losses from these generators, and are clearly well outside the collar.

223. Furthermore, it appears that this analysis was put forward, at least in part, to support ENMAX's argument that it is impossible for any line loss rule to comply with the conflicting requirements of Section 19 because the *Transmission Regulation* 2004 was fundamentally flawed. This position was not accepted for the reasons stated previously in my dissent.

224. However, I do find ENMAX's submission helpful that the *Transmission Regulation* 2004 places administrative limits on the allowable range of loss factors, thereby precluding many of them from being truly representative, and that the limits are asymmetric which introduces a bias.

11.4.4 Review of Section 19 of the Transmission Regulation

225. I turn now to considering the different requirements of Section 19 of the *Transmission Regulation* 2004. I will first address the various factors set out in Section 19(2). These are the factors the ISO was directed to have regard to when it determined loss factors. Consideration of Section 19(2)(d) overlaps with consideration of sections 19(1)(a) and 19(1)(c), and is accordingly deferred for later discussion in that context.

Sections 19(2)(a) and (b)

226. These two sections cross-reference one another. Section 19(2)(a) provides that loss factors must apply for a period of at least one year, but not more than five years, subject to Section 19(2)(b). Section 19(2)(b) deals with loss factor changes which may result from transmission upgrades or enhancements. There was no complaint or evidence engaging consideration of Section 19(2)(b). The Line Loss Rule provided that loss factors apply for one year. There was no evidence that the ISO made this determination for an improper purpose. The

justification given for doing so was to promote greater responsiveness to changes occurring in an evolving system. I accept that evidence, and find this justification to be reasonable. I conclude that the Line Loss Rule does not contravene Section 19(2)(a), and that Section 19(2)(b) does not come into consideration.

Section 19(2)(c)

227. Section 19(2)(c) states that loss factors must be determined for each location on the transmission system as if no abnormal operating conditions exist. AUC Decision 2012-105, the companion to this decision, addresses the matter of abnormal operating conditions and TMR. There is nothing further to add here.

Section 19(2)(e)

228. Section 19(2)(e) states that the loss factors must be one number at each location that does not vary. The AESO's evidence indicated that it took this clause to require the determination of loss factors for a group of generating units when those generating units are at the same location on the transmission system, and the ISO calculated loss factors on this basis. There was considerable evidence regarding the logic favouring, and benefits of interpreting location to mean each individual generating unit, however, I find that the ISO's interpretation of location for purposes of Section 19(2)(e) was reasonable, and conclude that the Line Loss Rule does not contravene Section 19(2)(e).

Section 19(2)(f)

229. Section 19(2)(f) requires that loss factor charges must not exceed two times the average system loss factor, nor loss factor credits exceed one times the average system loss factor. These limits are sometimes referred to as the loss factor collars. There was no evidence indicating that the loss factors resulting from the Line Loss Rule exceeded these collars. Accordingly, I conclude that the Line Loss Rule does not contravene Section 19(2)(f). I note that there was considerable mention and evidence which I accept, that conformity with these asymmetric collars is a restriction that compresses the loss factors resulting from the application of any line loss methodology selected to meet the requirements of Section 19(1), and introduces some bias into the loss factors resulting.

230. There was considerable evidence that loss factors under the previous regime experienced several issues, including the loss factors being fixed for five years in spite of changing topology of the transmission system, vintaging of generating units and extreme loss factors. Further, despite being a marginal loss factor methodology, the previous regime led to the under-collection of losses in some cases.

231. When drafting the *Transmission Regulation* 2004, the legislators would have undoubtedly been aware of the issues with the regime in place since 2000, including the large variation of loss factors. The *Transmission Regulation* 2004 does not include any provisions for a transition mechanism, and Section 19(2)(f) of the *Transmission Regulation* 2004 provides that loss factors must be no greater than two times the average system losses or no less than one times the average system losses. Given the range of loss factors under the previous regime, a transition mechanisms would lead to loss factors that are, for all intents and purposes, outside this defined range.

Sections 19(1)(a) and (c) and 19(2)(d)

232. 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 group, or group of generating units, relative to load. It is noteworthy that this section requires only "representative" tracking of impact on average system losses, and not that the loss factors be proportionate to or track in accordance with some formula or other precise relationship to each unit's impact on average system losses. The *Oxford Canadian Dictionary Second Edition* indicates that representative means "typical of a class or category". By this I take it in practice that to be representative, and thus comply with Section 19(2)(d), the resulting loss factors greater than average system losses represents a less desirable location, and loss factors less than average system losses represents a more desirable location. This goal is accomplished by the Line Loss Rule and loss factor methodology. Rather, criticisms were made that the tracking was not close enough to that which other alternatives being advocated would produce. However, the complainant's and other critical evidence was lacking or insufficient to persuade me that any tracking differences resulting from application of alternatives to the Line Loss Rule were great enough to conclude that the loss factors resulting from the Line Loss Rule were unreasonable or otherwise unjust, arbitrarily or unjustly discriminatory, or unduly preferential. Accordingly, I conclude that the Line Loss Rule does not contravene Section 19(2)(d).

233. Section 19(1)(a) requires the ISO to make rules to reasonably recover the cost of transmission line losses by establishing and maintaining loss factors based on their respective locations and their respective contributions to transmission line losses. The evidence satisfies me that the loss factors resulting from the Line Loss Rule were specific to a generating unit at a location. The engineering models for the AIES used by the AESO, including the R-matrix and power flows for 12 different time periods in each year, were location specific and calculated annually. The criticism and evidence of the complainant and its supporters was that application of the AESO's Line Loss Rule resulted in a muting of locational signal. I find that this evidence did not go beyond the examples considered and did not establish the extent and prevalence of muting created throughout the AIES. It is also unclear from the evidence how much difference would exist between loss factors produced by the Line Loss Rule and by the other ILF and MLF alternatives under discussion once the shifting or other manipulations were completed necessary to prevent excessive recovery and respect the loss factor collar. The statutory requirement that ISO loss recoveries should not exceed total system losses is apparent from the annual adjustment mechanism to eliminate any such difference mandated by Section 21 of the *Transmission Regulation* 2004. I find that the methodology selected by the ISO is an approach which is sufficiently "based on" location, and quantifies their contribution to transmission line losses. Therefore, I am satisfied that the Line Loss Rule meets the requirement in Section 19 for a location signal. Section 19 does not prescribe that loss factors must produce the strongest locational signal for each generating unit, and I am not persuaded that the degree of muting of locational signal under the Line Loss Rule is unrepresentative.

234. Section 19(1)(c) requires the ISO rule to establish a means of determining, for each location, loss factors and associated charges and credits which are anticipated to result in the reasonable recovery of transmission line losses. I interpret Section 19(1)(a), requiring the rule to "reasonably recover" the cost of transmission line losses, and Section 19(1)(c), requiring the loss factors determined to result in the reasonable recovery of these losses, to require that the recovery resulting should be reasonably close to anticipated losses and also achieved in a reasonable manner.

235. I accept the AESO's evidence that one of the results and a main reason for its selection of its methodology was the close approximation achieved to full recovery of transmission line losses, without further adjustments being made in the loss factor determinations – such as shifting and/or compression of loss factors, which adoption of an MLF methodology would require.

236. In my view, the requirement for reasonable recovery of losses under both sections 19(1)(a) and 19(1)(c), do require more than just that the Line Loss Rule achieve full, but not excessive, recovery of anticipated total transmission line losses. During the hearing parties agreed that assigning all generators a loss factor equal to the system average losses would recover the total cost of losses, but that such a method would not be reasonable. To help understand what is meant by reasonably recover the cost of transmission losses, the previous loss factor regime in place from 2000 to 2005 was considered. During some three month periods under the previous loss factor regime the shift factor applied to each loss factor was equal to 100 per cent of losses. Despite being a method based on marginal loss factors (it is accepted in this proceeding that methods based on marginal loss factors over-collect for losses, generally by a factor of two), in some periods there was under collection of losses. In addition there were instances where generators in close proximity to each other with similar operating characteristics had drastically different loss factors, which may have been due to loss factors being set for five years despite new units being commissioned during the period of 2000 to 2005.

237. The evidence at the hearing indicated that in developing its Line Loss Rule, the AESO made extensive efforts to determine the standard in terms of loss factor calculations and to investigate and learn about various line loss methodologies. It engaged well-qualified external technical expertise, Teshmont Consultants LP, to assist it in these efforts. There was also extensive industry consultation conducted in a transparent manner. In terms of the qualities of reasonableness identified in *Dunsmuir*, as quoted above, the AESO's articulation of both the process for selecting the Line Loss Rule and its outcomes are justifiable, transparent and intelligible. The consideration at hearing of other alternative line loss methodologies was relevant and satisfied me only that other different approaches exist which might be adopted, but not that those alternatives were better or that the Line Loss Rule was unreasonable. Accordingly, I am satisfied that the Line Loss Rule does not contravene sections 19(1)(a), 19(1)(c) or 19(2)(d) of the *Transmission Regulation* 2004.

Remaining Requirements of Section 19(1)

238. The AESO's and other evidence at the hearing satisfied me that the Line Loss Rule also met the requirements of (b), (d) and (e) of Section 19(1), none of which appeared to be contested.

11.5 Conclusion

239. As a result, I find that the Line Loss Rule does not contravene Section 19 of the *Transmission Regulation* 2004, and is not otherwise unjust, unreasonable, unduly preferential, arbitrarily, or unjustly discriminatory or inconsistent with or in contravention of the *Electric Utilities Act* 2003, or the regulations made under it.

(original signed by)

Tudor Beattie, QC
Panel Chair

12 Appendix 1 – Proceeding participants

Name of Organization (Abbreviation) Counsel or Representative	Witnesses
Alberta Electric System Operator (AESO) J. Smellie and L. Jamieson – Gowling Lafleur Henderson LLP	J. Mossing – Director, Transmission Support Dr. R. Burton – Teshmont Consultants LP
ATCO Power Ltd. (ATCO) M. Buchinski – Bennett Jones LLP Allison Sears – Bennett Jones LLP	C. Fuchshuber – Vice-President, Commercial – Strategic Planning H. Klinkenborg – Supervisor Regulatory & Analytics
Capital Power Corporation (Capital Power) D. Crowther – Fraser Milner Casgrain LLP	D. Jurijew – Senior Manager, Regulatory Affairs West
ENMAX Energy Corporation (ENMAX) D. Wood – Stikeman Elliott LLP	R. Stubbings – Director, Policy
TransAlta Corporation (TransAlta) L. Berg L. Ho – Macleod Dixon	R. Smith – Manager, Regulatory Affairs
Maxim Power Corp. (Maxim) M. Forster – Monte S. Forster	J. Bobenic – President and CEO J. MacCormack – engineering consultant Dr. S. Stoft – consultant Dr. R. Tabors – consultant
TransCanada Energy Ltd. (TransCanada) N. Berge	J. Paton – Director, Commercial Asset Management D. Levson – Bema Enterprises Ltd. L. Sibbald – consultant Dr. C. Roach – consultant V. Musco - consultant

Alberta Utilities Commission Commission Panel T. Beattie, QC, Panel Chair B. Lyttle, Commission Member M. Yahya, Commission Member Commission Staff J. Petch, Commission Counsel A. Davison, Analyst, Markets

13 Appendix 2 – Abbreviations

Abbreviation	Name in Full
ABCA	Alberta Court of Appeal
ABQB	Alberta Queen's Bench
ADC	Alberta Direct Connect Consumers Association
AESO	Alberta Electric System Operator
AEUB or Board	Alberta Energy and Utilities Board
ATCO	ATCO Power Ltd.
AIES	Alberta Interconnected Electric System
AUC or the Commission	Alberta Utilities Commission
BCCA	British Columbia Court of Appeal
Capital Power	Capital Power Corporation
DGA	Deferred Gas Account
DLR	Dominion Law Reports
ENMAX	ENMAX Energy Corporation
GSO	Generic stacking order
GW	Gigawatt
GWh	Gigawatt hour
ILF	Incremental Loss Factor
IPCAA	Industrial Power Consumers Association of Alberta
ISO	Independent system operator
kV	Kilovolts
kW	Kilowatt
Line Loss Rule	ISO rule 9.2 – *Transmission Loss Factors* and ISO rule Appendix 7 – *Transmission Loss Factor Methodology and Assumptions*
MW	Megawatt
MWh	Megawatt hour
MLF	Marginal Loss Factor
Milner	Milner Power Inc.
OLF	Ordinary Least Squares Loss Factors
Proceeding ID No. 790	AUC Proceeding ID No. 790
SCC	Supreme Court of Canada
SCR	Supreme Court Reporter
Teshmont	Teshmont Consultants LP
TransAlta	TransAlta Corporation

TransCanada	TransCanada Energy Ltd.
Transmission Development Policy	Government of Alberta 2003 *Transmission Development: the Right Path for Alberta – A Policy Paper*
TMR	Transmission must run

14 Appendix 3 – Transmission Regulation AR 174/2004

Part 5
Transmission System Losses and Credits

Transmission system loss factors

19(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 for each generating unit based on their location and their contribution, if at all, to transmission line losses;

(b) determine the anticipated transmission line losses for a specified period of time and determine the average transmission system loss factor for that specified period;

(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;

(d) provide a means by which, annually, a determination will be made of the difference between the anticipated transmission line losses and the actual transmission line losses;

(e) subject to section 21, provides a means through the application of a calibration factor to adjust the amounts paid by the application of the loss factor described in clause (c) so that the owners of generating units pay the actual transmission line losses or receive a credit for overpayment.

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

(a) loss factors must apply for a period of at least one year but not more than 5 years, subject to clause (b);

(b) a loss factor applied under clause (a) may not be changed during the period it applies unless, in the opinion of the ISO, a transmission system upgrade or enhancement materially affects transmission line losses;

(c) loss factors must be determined for each location on the transmission system as if no abnormal operating conditions exist;

(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;

(e) the loss factor must be one number at each location that does not vary, except as a result of revisions referred to in clause (b) or the reapplication of loss factors under clause (a);

(f) after determining which loss factors result in a charge or credit, every loss factor must be multiplied by a common number in order to limit the loss factors as follows:

(i) loss factors associated with a charge must not exceed 2 times the average transmission system loss factor, and

(ii) loss factors associated with a credit must not exceed one times the average transmission system loss factor.

Loss factors to be publicly available

20(1) The ISO must make rules with respect to the designation of loss factors in any place in Alberta where a generating unit is not located, and on request, determine a loss factor with respect to a generating unit that a person proposes to construct.

(2) Loss factors determined under section 19 and subsection (1) must be made publicly available for each location on the transmission system.

Adjustment of loss factors

21(1) In accordance with the rules, loss factors may be adjusted by a calibration factor to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis.

(2) If the actual cost of losses is over or under recovered in one year, the over or under recovery must be collected or refunded in the next year or subsequent years.

Recovery of transmission losses

22(1) In accordance with the ISO tariff and the loss factors determined under this Part,

(a) the owner of a generating unit must pay location-based loss charges or receive credits;

(b) importers of electric energy under a firm service arrangement must pay location-based loss charges or receive credits.

(2) A person receiving transmission service under an interruptible service arrangement for load, import or export must pay location-based loss charges that recover the full cost of losses required to provide this service.