Response To ATCO's Comments – 2006 Loss Factor Methodology

Below is a response to the ATCO email and letter, dated Thursday February 17, 2005, regarding the 2006 Loss Factor Methodology. The response focuses on the items raised in the letter and provides context to the overall solution regarding the application of loss factors in Alberta. The response does not address items regarding the intent or interpretation of the Transmission Development Policy or the 2004 Transmission Regulation beyond the solutions identified.

One of ATCO Power's criticisms of the proposed 50% area load adjustment methodology is that it does not "provide a locational signal) in a manner that satisfies the regulation".

It looks as if there may be differences in opinions between our interpretation of locational-based generating signals and ATCO Power's interpretation. Our interpretation is that the location based signal looks **only to the future** and has two functions:

1) By providing a locational pricing signal, encourage economic siting of new generating facilities in areas which would reduce transmission losses.
2) Locational based signals provide a means for the AESO to charge generators for the cost of transmission losses based on their impact to system average losses.

We believe that the proposed methodology does accomplish both aspects of our interpretation of the objectives. It should also be noted that the regulation limits the range of loss factors to an envelope of two times system average losses for charges and one times system losses for credits. Our proposed loss factor methodology provides results that are compliant with this requirement.

In the following, the numbers calculated by ATCO Power will be used as an example. It is recognized that shift factors must be applied to the tabulated loss factors to account for all losses. However, as the shift factor is applied equally to all generators and as locational based signals are differential quantities, the values tabulated are indicative of the locational-based signals sent to the generators.

In cases 3 and 4, load is greater than generation at bus 2. The differences in R bus (50% Load Area Adjustment) loss factors between the two buses (-0.44% and –0.5% respectively) would encourage generation at bus 2 rather that bus 1, reducing losses in the system.

In case 5, generation is greater than the load at bus 2. The difference in R bus (50% Area Load Adjustment) loss factors between the two buses (0.3%) would discourage additional generation at bus 2 and encourage additional generation at bus 1.

In cases 1 and 2, load and generation are balanced at bus 2. The difference in R bus (50% Area Load Adjustment) loss factors between the two buses is small (0.1%) but slightly favours additional generation at bus 1, i.e. electrically closer to the largest load.

Similar conclusions can be drawn from the ML/2 method tabulated.

We believe that the ILF methodology tabulated by ATCO does **not** always give correct signals according to our interpretation. In cases 3 and 4, where load exceeds generation at bus 2, the ILF differential signal (-1.5%) encourages new generation at bus 2. However in case 5, where generation exceeds load, there is no signal; we believe new generation should in fact be discouraged at bus 2. In cases 1 and 2 where the generation and load are balanced at bus 2, the signal (-0.5, and –1% respectively) encourages new generation at bus 2, when in fact new generation should be located at bus 1, close to the larger load.

Some Results

Fig 2: Two bus system

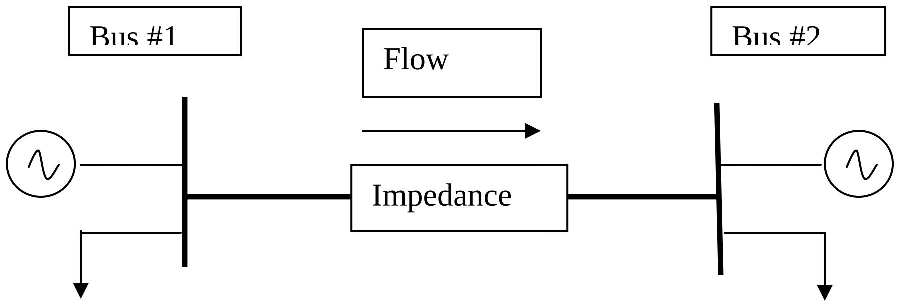


Table 1: Loss Factor Examples

Case#	Gen1 (MW)	Load1 (MW)	Gen2 (MW)	Load2 (MW)	Imp. (p.u.)	Flow (MW)	Losses (MW)	RBus(50%Area)		MLF/2		ILF*	
								LF1(%)	LF2(%)	LF1(%)	LF2(%)	LF1(%)	LF2(%)
1	10,000	10,000	100	100	0.01	0	0.00	0.0	0.05	0.0	0.0	0.0	-0.5
2	10,000	10,000	100	100	0.02	0	0.00	0.0	0.1	0.0	0.0	0.01	-0.99
3	10,050	10,000	50	100	0.01	50	0.25	0.0	-0.44	0.0	-0.5	0.01	-1.49
4	150	100	50	100	0.01	50	0.25	0.25	-0.25	0.25	-0.25	0.75	-0.75
5	10,000	10,025	50	25	0.01	-50	0.0625	0.0	0.3	0.0	0.25	0.0	0.0

*ILF calculated for 50MW increment

Note: Reproduced from “ATCO Power’s Comments On Transmission Loss Factor Methodology Discussion Paper (Feb 9, 2005 Draft)

We have analyzed (using the R bus methodology) a simple situation (similar to the system given by ATCO Power, where a new generator has the choice of locating at one of two ends of a transmission system, either close to a major generation/load center or close to a small remote load. This is shown by example in Figure 1. In both cases, the new generator will displace some of the existing local generation.

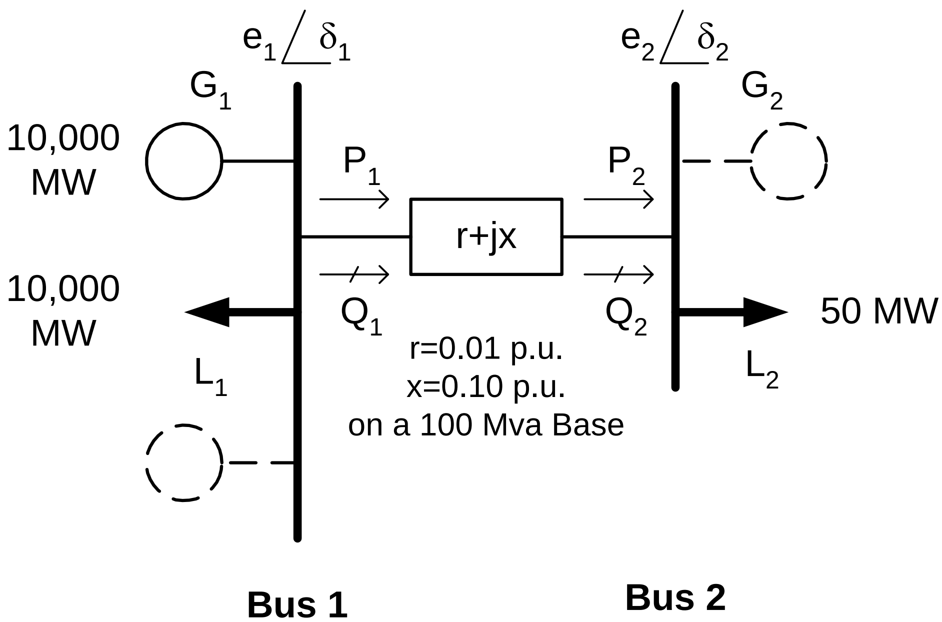


Figure 1 Simple System

Losses and loss factors have been calculated for the new generator for various capacities and for the two possible locations. In addition, the sensitivity to load factor was explored by calculating losses and loss factors for 100% load factor and generator capacity factor as well as 75% load factor (between 100% and 50% load) with 100% generator capacity factor.

The 100% load factor curves are shown in Figure 2 and Figure 3. The 75% load factor curves are shown in Figure 4 and Figure 5.

If the generator locates close to the major load center (Bus 1), its assigned loss factor would be the same as that of all the rest of the generators supplying the major load center. If the existing generation were sitting on top of the major load center so that no local losses are incurred, the loss factor assigned to the new generator (and all the rest of the generators) would reflect only the impact of the 50 MW load on losses. This would be only slightly greater than zero. Both the existing large generation and the new small generator would be charged for the transmission losses to the remote load, but as the load is small compared to the total generation, the loss factor assigned would be small. The loss factor shared by all generators would be 0.0051%. Thus the new generator will displace some existing generation (and hence revenues) but will pay a small charge along with all the other generators for supplying losses to the remote load.

Figure 2

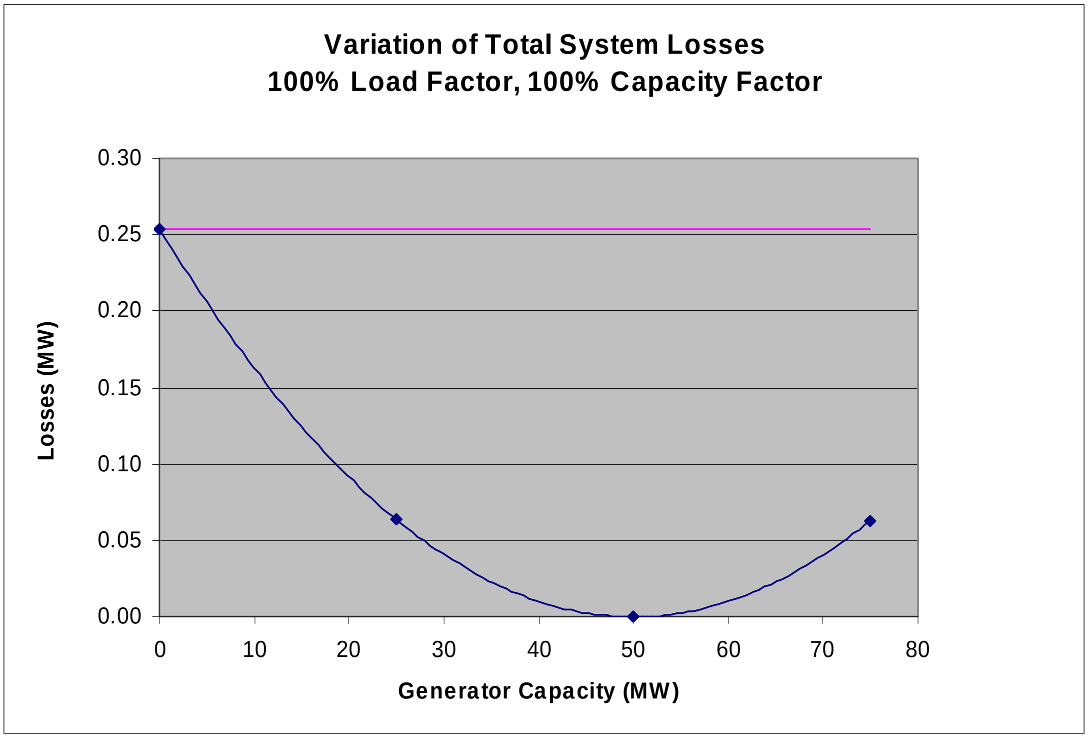


Figure 3

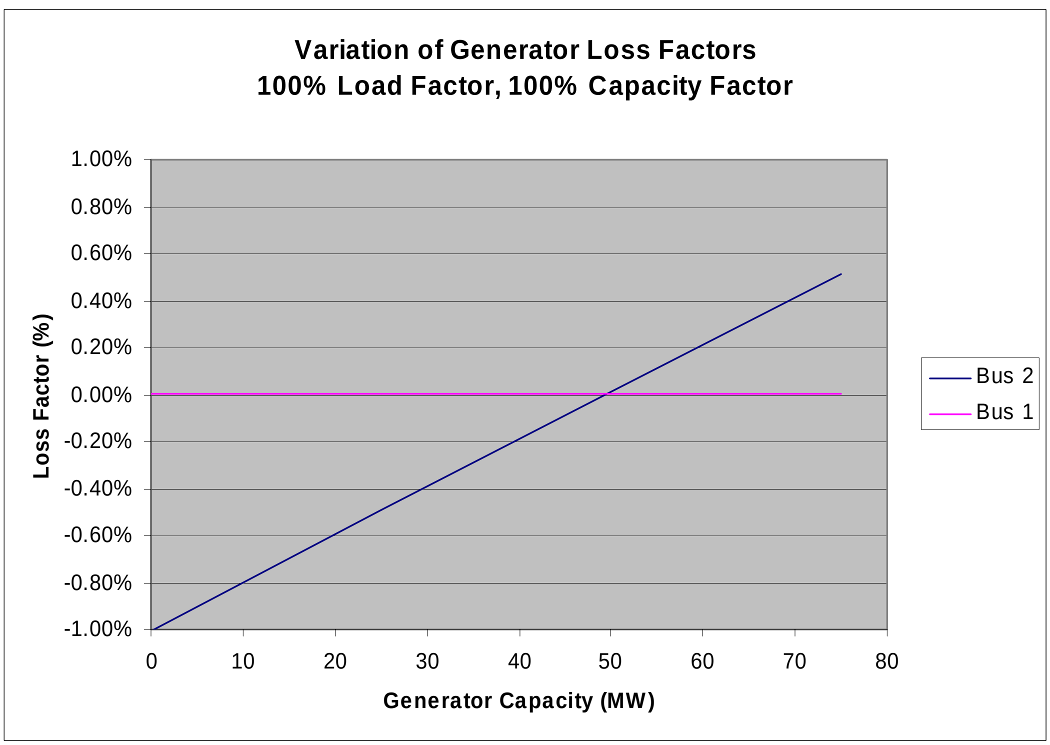


Figure 4

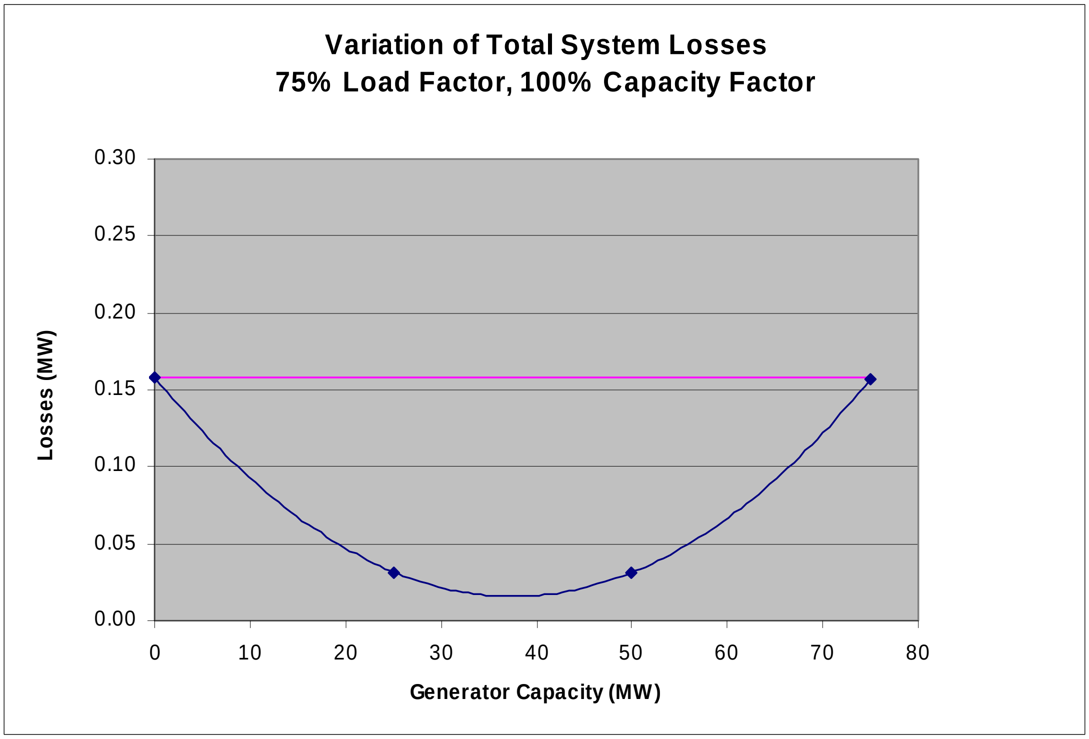
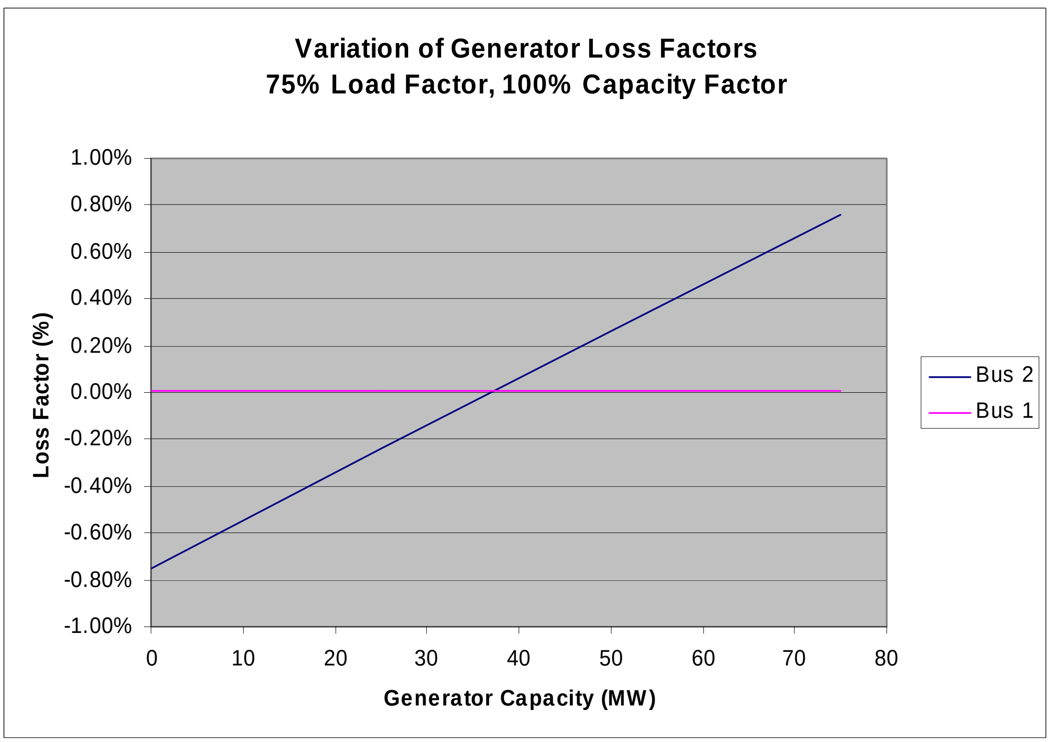


Figure 5



If the new generator were to locate at the new load bus and say the capacity was very small compared to the load, the losses would be reduced, but as all generators were originally being charged for losses, all generators will also share the credit for the loss reduction. The new generator would receive a large credit for the loss reduction (about 1% loss factor credit). As well, the large remote units, which are also paying for losses, must also benefit. As the new generator capacity in this case is small compared to total capacity and remote load, the net reduction in losses is small so the reduction in large generator loss factor is almost insignificant, but it does exist.

If for example the new generator were larger, say ½ the capacity of the load, (25 MW of new generation at the 50 MW load bus), the overall system losses are significantly reduced. The losses in this case would be about 25% of the original losses. The new generator would still receive a significant credit for the reduction in losses (a loss factor credit of about 0.5%), while the large generators would see a small reduction in their loss factor from .0051% to .0025%, reflecting their share in loss allocation.

If the new generation capacity matched the load, the total system loss reduction would be 100%, and on the basis of shared allocation of losses, all generators benefit and the loss reduction for all generators is a reduction in assigned loss factor from 0.0051% to zero (including the new generator located at the load bus).

If the capacity of the new generator exceeds the load, (say 75 MW compared to the 50 MW load) total system losses would start to increase as the new generation displaces some of the existing large capacity generation. In this case however, the large generators are now electrically closer to the net system load. Similar to the condition with the 25 MW unit supplying the local load (and receiving a credit), the large generators should also should receive a credit. At the same time the small generator at bus 2 should receive a loss factor charge because it is significantly contributing to the losses. For the 75 MW unit, the factor would increase from zero (at 50 MW capacity) to 0.51% at 75 MW capacity. The rest of the generators, also sharing in the loss distribution would see a small credit of 0.0025%, because they are now closer to the effective load on the system than the remote generator.

For a 50 MW generator at bus 2, the loss factor assigned to the new generator would be zero for this example. However, any difference between generator output and load (either surplus or deficit) would result in an increase in total losses. In a market environment where generation is dispatched according to system demand and market conditions, the output of the generator will not match the load, and losses will be incurred. Although locating the generator at the load has reduced the system losses, and should receive a credit for this, it must also be penalized for increased losses associated with any difference between output and load.

This is particularly evident in an example where the new generation capacity matches peak load, but load varies to as low as 50% of peak load, with a 75% load factor. If it is assumed that the new generator is competitive in the market and operates at 100% capacity factor, the average system losses would be about 0.032 MW and the loss factor that would be calculated for this example would be about 0.26%, reflecting increased losses because of net exports from the load bus. If the generator capacity were sized on the basis of the average load of 37.5 MW, its assigned loss factor would be close to zero. Its contribution to losses at peak load (50 MW local load) would be about 0.02MW and also losses at 50% load (25 MW local) would also be about 0.02 MW. The increase in losses (which should be reflected in a charge) is counteracted by the overall reduction in average system losses, both of which are shared by all generators based on their individual contribution to the losses. The result is that the net charges to the generator would be 0.0%.

The locational-based signal for locating close to the load in the example given exists, but it is small. The main reason for this is that the all generators are required to pay for system loss increases in proportion to their capacity, and therefore must receive credits for loss reductions on the same basis. As the new generator is only a small fraction of the total generating capacity, it receives only a small fraction of the overall loss reduction benefit.

In the two-bus system, described above, if there were transmission losses associated with delivering power from 'Bus 1' to the load center, the loss factor at 'Bus 1' would be increased. The loss factors calculated for 'Bus 2' would be increased by the same amount, so the locational based signal would remain the same.

If the total generation and load at 'Bus 1' were reduced by 50%, the locational-based signal to locate at bus 2 would double.

If the new generating station has less capacity than the load, the generator receives a strong credit for locating close to the load. If the capacity of new generator is greater than the load it receives a large loss charge.

In a distributed, generation load bus environment, the proposed 50% area load adjustment methodology does provide a signal to locate such that system losses are reduced. The methodology encourages generation to be close to load centers, provided that the total generation does not exceed the load at that load centre.