Alberta Electric System Operator

Loss Factor Methodologies Evaluation
Part 4 - Determination of Opportunity Service 'Raw' Loss Factors

Final

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ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION
PART 4 - DETERMINATION OF OPPORTUNITY SERVICE
'RAW' LOSS FACTORS

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'RAW' LOSS FACTORS

1 INTRODUCTION

A methodology has been proposed for the calculation of raw loss factors for generators [1]. The loss factors calculated using the proposed method represent the average contribution of each generator to total system losses.

This report outlines the development of a methodology for determining raw loss factors for opportunity services such as imports or exports or DOS loads. While the emphasis in this report is on the treatment of intertie loss factors, similar methodologies can be applied to the treatment of DOS loads.

2 CRITERIA

An initial approach to determining loss factors for opportunity service connections was to treat all opportunity services in the same manner that generators are treated. Opportunity service loads or exports could be treated as negative generators.

A closer examination of the Alberta regulations however indicated that a different treatment was required for opportunity services. For generators, the loss factors applied to generators are to be based on the average contribution to system losses. For opportunity service, however, the loss factors are to be based on actual contributions to system losses. The loss factors must also provide a locational-based signal. Loss factor for each opportunity service must be revenue neutral to the AESO.

In developing a methodology, the following additional principles put forward by stakeholders were adopted.

- There would be no 'double dipping' by the AESO under export conditions. This is, essentially a restatement of the regulation requirement, that transactions for each opportunity service must be revenue neutral.
- A single annual loss factor is preferred for each opportunity service.

3 CALCULATION OF LOSSES ASSOCIATED WITH IMPORTS AND EXPORTS

3.1 Loss Factors Based on Average of Actual Contribution to Losses

To provide a basis for developing the methodology, load flow simulations were carried out for a variety of import and export conditions over the set of interconnections to BC and the Saskatchewan interconnection at Mc Neill.

The series of base-case load flows that were developed for the generator loss factor calculations formed the basis of the load flows developed for the evaluation of import/export losses. Intertie activity was reduced to close to zero in each of these 'generator base-case' load flows.

A total of 60 variation load flow cases were performed representing each of the three dispatch conditions (peak, medium and low load) for each of the four seasons (winter, spring, summer and fall). For the BC interconnection, losses associated with power transfers of 600 MW and 200 MW were evaluated while for the Saskatchewan interconnection, losses associated with 150 MW of interchange were calculated.

The import/export load flows were developed with no adjustment to the Alberta loads but with adjustment to Alberta generation based on the AESO generator stacking order.

The interconnection to SaskPower was modelled as a constant power, unity power factor positive or negative injection at the McNeill 138 kV bus. The swing bus for the system is the equivalent generator at the end of the Langdon to Cranbrook 500 kV circuit that represents the BC and western US systems. Power interchange (equal to the net flow on the 500 and 138 kV interconnections to BC) was monitored and adjusted to target levels by adding or removing generation from the Alberta system.

On completion of the load flow development, it was observed that it might not be practical to export 150 MW to SaskPower because of transmission constraints in the Alberta system. . The limits of interchange with Alberta and Saskatchewan are defined as per OPP-503, 'Empress Area Operation'. The load flows were not repeated, however as they were only being used to develop the methodology, not actual loss factors for the interconnections.

The system losses for each load flow and the change in system losses from the base case conditions are summarized in Table 1). The losses and change in losses from base case conditions are shown in Figure 1) through Figure 5). The table and figures show that the losses are sensitive to season, system loading condition, and the extent of the power of interchange with BC and SaskPower. To reduce the number of variables for which results were to be presented, the losses for the medium and low import conditions were averaged and the average losses for each interchange condition and season are shown in Figure 6) through Figure 9).

To extract the mutual effects between flows on each of the BC and SaskPower interties, the losses were further averaged over each of the seasons, and average 'incremental' loss factors determined by dividing the change in losses (from base case) for each interchange condition by the change in power flow across the interconnection.

The resultant graphs shown in Figure 11) through Figure 14) confirm that the mutual effects on losses due to flows on the other intertie are significant. Under import conditions from BC, flows over the SaskPower interconnection can alter the average total losses by as much as 15 to 20 MW. In a similar fashion, the average change in system losses due to SaskPower imports and exports will vary by as much as 20 MW as flows over the BC interconnection are varied.

If a loss factor were assigned to each interconnection based on the average of their actual impacts on losses, (as shown in Figure 12) and Figure 14) for BC and SaskPower respectively) the loss factors would be:

	Possible Loss Factors Based on Average of Actual Contribution to Losses	
Station	Loss Factor For Imports	Loss Factor For Exports
BC	4.9% Credit	11.7% Charge
SaskPower	3.2% Credit	17.4% Charge

Table 2) shows the assignment of losses based on the above loss factors for each of the 60 load flow conditions studied. If each of the load flows is given equal weighting (as implied by averaging the actual contribution to losses to obtain intertie loss factors) then the loss factors on average would recover almost all of the losses as shown in the following:

	All Cases	Imports	Exports
Total Actual Change in Losses (MW)	1791.1	-399.6	2190.7
Assigned Total Change in Losses (MW)	1760.5	-368.9	2129.4
Unassigned Losses (MW)	-30.6	30.7	-61.3
Number of Cases	60	20	40
Average Unassigned Losses per Load Flow (MW)	-0.5	1.5	-1.5

There would be a total of about 30 MW of losses unassigned or on average, about 0.5 MW per load flow condition. Exports would be under-assigned by about 1.5 MW per load flow while imports would be over-assigned by a similar amount per load flow.

While using this averaging method to establish intertie loss factors accounts on average for almost all of the losses, it does not satisfy the 'no double dipping' criteria. Generators would be charged for the change in losses associated for delivering the additional power under export conditions and reduced power under import conditions.

Under export conditions, there is a total of about 16,400 additional MW or on average about 410 MW per export load flow condition evaluated. Under import conditions there is a total reduction of 8,200 MW or about 410 MW per load flow. If an average system loss factor of 5% is assumed, this represents additional revenue to the AESO under export conditions of about 20.5 MW per load flow, and a shortfall in revenue of about 20.5 MW per load flow under import conditions. Together with the average assignment based on import/export loss factors, there would be an over-assignment of 19 MW per load flow under export conditions and an under-assignment of 19 MW under import conditions for a net over-assignment of on average 19 MW per load flow.

Based on this analysis, it would appear that generators would be overcharged under export conditions and over-credited under import conditions with on average a total assignment of losses that exceeds the actual losses by about 19 MW per load flow. This type of methodology would result in significant net 'double dipping'.

Based on the above it can be projected that a similar methodology applied to DOS loads would in general result in overcharging of generators.

3.2 Intertie Loss Factors Taking Into Account Charges to Generators

A methodology was developed for the calculation of intertie loss factors that would take into account any charges or credits to generators such that in general, the total charges assigned to the interties and to the generators would only just recover the average losses as a result of the intertie transaction. The main approach to the calculation is to first subtract the expected charges to generators (expressed in terms of assigned losses) from the losses from each load flow. Similarly expected credits (again expressed in terms of assigned losses) are added to the losses from each load flow.

Import and export loss factors are then determined for each intertie such that the net change in charges from the base case load flows (i.e. change in actual losses less assigned losses to generators less assigned losses to interties) are zero for each of the following conditions:

- All import conditions from BC
- All import conditions from SaskPower
- All export conditions to BC
- All export conditions to SaskPower.

Loss factors calculated using this approach would be:

	Possible Loss Factors Based on 'No Double Dipping'	
Station	Loss Factor For Imports	Loss Factor For Exports
BC	1.9% Credit	10.1% Charge
SaskPower	3.7% Credit	18.2% Charge

Loss factors that were assumed for generators were based on the methodology presented in Part 1 of this report.

Detailed results of the calculations are given in Appendix A. Loss factors for each interconnection and direction of flow were calculated directly from the solution of four simultaneous linear equations based on the data in the summary spreadsheet shown in Appendix A. The loss factors were calculated in a MATHCAD worksheet and imported into the spreadsheet for validation.

With the intertie and generator loss factors above, there are surpluses and shortfalls in assignment of losses for each of the load flow conditions. The maximum surplus for the conditions studied was 23.3 MW occurring for spring medium export conditions with 150 MW to SaskPower and about 200 MW to BC. The largest shortfall of 37.3 MW occurs for fall low conditions with 150 MW export to SaskPower and about 600 MW export to BC.

Although there is a relatively large surplus or shortfall on an individual load flow basis the net shortfalls for each of the four conditions described above are zero (i.e. for all conditions where there are exports to Saskatchewan, the net surplus or shortfall is zero, regardless of the loading on the BC intertie). Similarly for all conditions where there are exports to BC the net surplus (and shortfall) is zero. This also holds for all import conditions as well. The net surplus/shortfall for each of these conditions is summarized below:

Condition	No. of Cases	Average Surplus (MW)
Imports From SaskPower	12	0.00
Exports to SaskPower	24	0.00
Imports from BC	28	0.00
Exports to BC	32	0.00
All cases	60	0.00
BC approx 200 MW	24	4.02
BC approx 600 MW	24	-5.34
Peak	20	-1.99
Medium	20	12.99
Low	20	-10.99

From the above it can be seen that there is some averaging of the effects of interchange with BC. There is a net surplus for conditions where the interchange is 200 MW but a shortfall of similar magnitude for conditions where interchange is 600 MW. Similarly, there is averaging of surpluses and shortfalls between medium and low load conditions but when all conditions are considered, there are no net surpluses or shortfalls. Hence, this approach to calculation of intertie loss factors would not result in 'double dipping' by the AESO.

3.3 Accuracy of Virtual Load Flow Calculations

As the 'R' matrix developed for the generator loss factor calculations defines the relationship between net power injections at each of the load flow buses and system losses, investigations were carried out to establish the accuracy of using virtual load flows, based on the 'R' matrix to estimate system losses for the various import-export conditions.

For each virtual load flow, two simultaneous equations are solved:

$$\Delta L = \mathbf{\Delta \vec{P}}^{T} \mathbf{R} \mathbf{\Delta \vec{P}} \qquad \text{Equation (1)}$$

$$\Delta L = \sum_{i} \Delta P_i \qquad \text{Equation (2)}$$

ΔL is the total change in system losses as a result of the imports and/or exports
$\mathbf{R}$ is the R-Matrix developed for the base case load flow
$\mathbf{\Delta \vec{P}}$ is a vector of changes in power injections at each affected bus in the system
ΔP_i is the change in power injection at the i[th] bus in the system. This could represent imports to the system at selected buses, exports from the system at selected buses or changes in generation (or load) at selected buses to compensate for the changes in import or export.

For a given set of injections, Equations (1) and (2) above are over-constrained, and as a result, the change in losses evaluated using Equation (1) above could be different from the change in losses evaluated from Equation (2). To solve the two equations to a single change in losses, it is necessary to introduce a slack variable into the system of equations.

One could designate a single bus as the slack bus for the system, and the change in injections at that bus would become an unknown as well. Equations (1) and (2) above would reduce to two solvable simultaneous equations with two unknowns, (ΔL and ΔP_s) where:
ΔP_s is the change in injections at the slack bus.

Use of a system slack bus for loss factor calculations is not an attractive option as the choice of a system slack bus could have an impact on loss factor results. Another option is the introduction of a distributed slack bus, i.e. injections at a group of buses are all changed by a common factor 'δ'. Several options for application of the factor exists, such as:

- Injections due of all generators in the system not changed by imports, exports or balancing (discussed hereinafter as 'distributed generation').
- Injections due of all loads in the system not changed by imports, exports or balancing (discussed hereinafter as 'distributed load').
- Net injections at all buses where injections are not defined by imports, exports or changes to generation or load to balance the imports/exports.

Many other options exist; however, the investigation discussed hereinafter was limited to evaluating only the impacts of distributed load and distributed generation on the calculation of intertie loss factors. For both of these options, Equations (1) and (2) above would reduce to two solvable simultaneous equations with two unknowns, (ΔL and δ):

To evaluate the accuracy of the virtual load flow process, virtual load flows were carried out for each of the 60 import/export loading conditions described in Section 3.1. Injections were adjusted at each of the inter connection locations and at each of the generator buses re-dispatched from the base-case load flows to cater for the imports/exports. The change in system losses were evaluated for both 'distributed load' and 'distributed generation' slack bus options.

The changes in losses from the base cases that were calculated using the virtual load flow solution were compared to the changes in losses that were calculated using actual load flow solutions from PSS/E. The difference between the sets of losses represents an error associated with the virtual load flow solution approximation. The error (in MW) divided by total effective generation in the system expresses the error as a change in system shift factor that would be need to be applied to compensate for the error. The errors in loss calculations were evaluated for both the distributed load and distributed generation slack treatments.

Figure 15) summarizes errors introduced by the virtual load flow calculations for both slack treatments. The figure shows that:

- The magnitudes of the errors are dependent on the level of import or export with magnitude of error increasing with the magnitude of import or export.
- At any given level of power transfer through the interconnection, there is a significant variation in error dependent on season and system loading condition.
- The virtual load flow tends to underestimate losses for most operating conditions but overestimates losses for several lower level (150 to 400 MW) export conditions.
- The maximum error introduced is an underestimate of losses by about 0.35% under maximum import conditions and an overestimate of losses by less than 0.1% under the lower level export conditions.
- Distributed load and distributed generation treatments result in loss estimate errors that are very similar in magnitude with distributed load yielding slightly more accurate results..

The following table summarizes the average error (compared with actual load flows) introduced by the virtual load flow method.

	Average Virtual Load Flow Error		
Net Interchange (MW)	Distributed Load	Distributed Generation	Difference
750	-0.16%	-0.17%	-0.01%
600	-0.15%	-0.17%	-0.01%
350	-0.04%	-0.04%	0.00%
200	-0.01%	-0.01%	0.00%
150	-0.02%	-0.03%	0.00%
Overall Average	-0.08%	-0.08%	0.01%

The table demonstrates that while the errors introduced by a virtual load flow approach may vary from simulation to simulation, the overall average error is very small, i.e. less than 0.1%. This is well within the accuracy of the overall loss factor calculation process.

The table also shows that if the changes in load, loss and generation are balanced, the use of distributed load or distributed generation has very little impact on error.

3.4 Impact of Alternative Balancing Methodologies

The changes to generation that were used in the calculations described in Section 3.3 above were extracted from full system load flows. The generation in each of the full system load flows was established based on the generic stacking order. To adapt the methodology described in Section 3.2 to interface with a virtual load flow solution would require the development of an iterative procedure in which an initial dispatch is prepared based on the level of import or export and an estimate of the impact of the change in intertie dispatch on losses. Losses would be calculated for the new generator dispatch schedule, and generation at the marginal unit adjusted to compensate for the change in losses. This may require stepping to the next or previous generator in the stacking order if the maximum or minimum power out level of the marginal unit is exceeded. The process is repeated, improving the loss estimate at each step until an acceptable tolerance is reached. This process is referred to in the discussions herein as a specific generation balancing process as specific generation is adjusted to balance the change in imports or exports as well as the change in system losses resulting from the required changes in generation.

Two alternative methodologies were evaluated. Both methodologies use a direct solution; i.e., the change in system losses can be computed directly with no iteration involved. In both methodologies, the direct impact of intertie power changes are evaluated in the loss calculation, but to balance the change in flows and resultant change in system losses, either:

- System load is adjusted by a constant factor. This is identical to the distributed load slack adjustment discussed in Section 3.3; however, in this scenario, all loads are adjusted to compensate for the changes in intertie flow as well as the change in losses.
- System generation is adjusted by a constant factor. This is identical to the distributed generation slack adjustment discussed in Section 3.3; however, in this scenario, all generation is adjusted to compensate for the changes in intertie flow as well as the change in losses.

Losses that are calculated with each of these methodologies are compared to the losses calculated with generator balancing based on the stacking order in Figure 16). The figure shows that the calculated values of losses for the three methodologies are considerably different. The observations are:

- Distributed generation appears to have a more profound impact on system losses than distributed load.
- The average change in losses computed assuming distributed load is close to the average change in losses computed with balancing of specific generation from the stacking order under export conditions.
- The average change in losses computed assuming distributed generation is close to the average change in losses computed with balancing of specific generation from the stacking order under import conditions.

The most significant component of AIES generation lies to the north of the north-south 240 kV transmission corridor between Edmonton and Calgary, and the interties are connected to the south of the corridor. Adjusting generation to compensate for the imports or exports implies a significant change in flows over the north-south transmission corridor and hence a significant impact on losses. AIES load on the other hand is more evenly distributed on either side of the corridor, hence adjusting load to cater for imports and exports is likely to have a lesser impact on north-south flows and hence on losses than adjusting generation.

This does not necessarily mean that one methodology would favour interconnections in the south of Alberta and another would favour interconnections north of the bulk transmission corridor. As it is proposed that the same methodology could be applied to both interties and DOS load, the selection of load flow methodology does not necessarily favour DOS loads in either the south or the north.

The change in losses were computed for 50 MW of DOS load in the south and the change in losses were also computed for 50 MW of DOS load at the north end of the 240 kV corridor close to Edmonton. Both slack methodologies were evaluated for both DOS load locations. The impact on losses of each load and methodology is as follows:

Impact of Methodology on Change in Losses
Due to DOS Loads

DOS Loads	Distributed Load MW	Distributed Generation MW	Difference MW
South	4.1	9.1	5.0
North	-3.8	0.4	4.2
Difference	7.9	8.7	0.8

Both methodologies indicate higher losses in the south than in the north. The difference in calculated losses between stations however remains about the same. As a result the strength of locational-based signals generated by the two methodologies would be similar. I.e. neither methodology would significantly favour one location over the other.

As discussed in Section 3.2, it is proposed that change in losses attributed to generation based on their loss factors be subtracted from the total change in losses as a result of a DOS load or intertie transaction when loss factors for interties and DOS loads are established. The resultant average raw loss factors for the two stations and for each methodology would be:

Average Raw Loss Factors

DOS Loads	Distributed Load	Distributed Generation	Difference
South	8.21%	13.16%	4.95%
North	-7.64%	-3.53%	4.11%
Difference	15.85%	16.69%	0.84%

The impact of methodology on average raw loss factors for DOS loads is significant with distributed generation giving loss factors that are higher by about 4 to 5%. The differences between loss factors for both methodologies are almost the same; hence, the strength of the locational signal is again essentially the same for both methodologies.

With normalizing and loss factor compression taken into account, the differences in actual compressed loss factors for the two DOS loads as a result of the two different methodologies are reduced as shown below:

Compressed Loss Factors

DOS Loads	Distributed Load	Distributed Generation	Difference
South	9.23%	9.71%	0.48%
North	-4.86%	-2.75%	2.11%
Difference	14.09%	12.46%	-1.63%

Loss factors for DOS loads in the south are compressed to the maximum charge with distributed generation. Loss factors credits for DOS loads in the north would be compressed to the maximum permitted credit. The result is an increase in the difference in locational signal with distributed load exhibiting a slightly greater signal.

The impact of methodology on intertie loss factors was also evaluated. The average raw loss factors for the interties were calculated for the specific generator balancing, distributed load and distributed generation methodologies, as follows:

Average Raw Loss Factors

	Specific Generation	Distributed Load	Distributed Generation
BC Export	9.23%	8.76%	14.69%
SaskPower Export	15.36%	14.34%	21.13%
Difference	6.13%	5.59%	6.44%
BC Import	-1.57%	-0.51%	-3.76%
SaskPower Import	-2.53%	-1.89%	-5.75%
Difference	-0.96%	-1.37%	-1.99%

Average raw loss factors are dependent on methodology selected, with distributed generation indicating much larger charges for exports and credits for imports. Average raw loss factors computed with specific generator balancing and distributed load are closer. Even with the large differences in raw loss factors, the locational signals generated are similar. The signal for exports generated by each method is similar with a range of 5½ to 6½ %. The signal for imports is about 1 to 2%.

Compressed loss factors for interties are much less sensitive to methodology. The compressed loss factors for each of the three balancing methods are:

Compressed Loss Factors

	Specific Generation	Distributed Load	Distributed Generation
BC Export	9.71%	9.42%	9.71%
SaskPower Export	9.71%	9.71%	9.71%
Difference	0.00%	0.29%	0.00%
BC Import	-0.84%	0.21%	-2.98%
SaskPower Import	-1.80%	-1.11%	-4.86%
Difference	-0.96%	-1.31%	-1.87%

Export loss factors are typically compressed to the maximum charge resulting in a loss of locational signal between the two export locations. With distributed load, loss factors for BC exports are not compressed to the limit and as a result, there is still a small locational signal favouring BC exports over SaskPower exports.

SaskPower import loss factors are compressed to the minimum value with distributed generation. However, the locational signals for import credits are relatively unchanged after normalization and compression. The signal for imports remains within the range of 1 to 2 %.

Another factor to be considered in the evaluation of methodologies is the impact of the methodology on average shift factor for the system. The average raw loss factors for generators are common to all of the intertie/DOS load methodologies considered. Therefore the impact of methodology on average shift factors therefore represents the impact that the methodology would have on generator loss factors. The average shift factors computed for each of the three methodologies are:

Shift Factors

Specific Generation	0.71%
Distributed Load	0.72%
Distributed Generation	0.63%

Note: The shift factors are added to 'raw' loss factors to obtain normalized loss factors.

The shift factor takes into account differences between power and energy forecasts; hence, only the differences in shift factors have relevance to the evaluation of methodologies. The shift factor for the distributed generation methodology is lowest, implying that loss factor charges to generators would be slightly lower with this methodology. The shift factors for distributed load and specific generation are almost identical, indicated that impact on generator loss factors for the two methodologies are the same.

4 RECOMMENDATIONS

Based on the evaluation of alternatives for DOS and interties loss factors the following methodology is recommended:

- Base-case load flows for calculation of all opportunity service loss factors should include no opportunity service transactions. This includes no DOS loads and no net intertie activity. Generator adjusted raw loss factors should be calculated for these load flow conditions based on the methodology described in Part 1 of this report.

- The impact of intertie flows and DOS loads on transmission losses should be determined by carrying out variation-case load flows on each of the base cases. The variation-case load flows should reflect expected operating conditions in the system. For interties, the load flows should include cases with simultaneous imports, simultaneous exports and possibly simultaneous import/export conditions if these scenarios are expected to occur. Power transfer levels selected for each load flow should reflect averaging based on equal weighting applied to each load flow.

  As lower power transfers and lower volumes are typically involved in DOS load transactions it is sufficient to treat each DOS load individually, i.e. with no overlapping transactions with interties and other DOS loads.

- Load flows should be carried out using the virtual load flow procedure. This is an approximate procedure but the computed losses and impact on loss factors are well within the accuracy of the overall loss factor calculation.

- The impact on losses should be calculated using a distributed approach. While specific generator balancing may be considered as more representative of individual system loading conditions, both the distributed load and distributed generation methodologies have a significant advantage in that their methodologies are simpler to implement, the solutions are direct (i.e. non-iterative) and as a result are less subject to the introduction of judgmental errors into the calculation process. In addition, the direct solution calculations are 100% repeatable.

- The distributed load methodology is recommended. Both average raw and normalized-compressed loss factors calculated with distributed load are closer to the comparable loss factors calculated with specific generator balancing than the values computed with distributed generation. The distributed load methodology is also consistent with the approach proposed for the calculation of generator loss factors.

- Once the change in losses is established for each of the virtual loading conditions, the change in losses that are assigned to generators as a result of the transaction should be subtracted from the actual change in losses to establish the change in losses that are assigned to the interties or DOS loads. This should be zero if the distributed load methodology as proposed is adopted. However, if circumstances arise such that the recommended balancing methodology is changed, the contribution of generators to the change in losses must be taken into account to avoid 'double dipping'. The contribution from the generators should be based on the average adjusted raw loss factors for each season as calculated using the methodology described in Part 1 of this report.

- Average raw loss factors should be determined for each season based on the average contribution of each intertie transaction such that change in total losses are on average neither overcharged nor undercharged to the generators as a result of the intertie or DOS load transaction.

- Once average seasonal raw loss factors are established for all generators and all intertie and DOS load transactions, the loss factors should be normalized according to the methodology described in Part 2 of the report and compressed as discussed in part 3 of the report.

The above-proposed methodology has been implemented in software for use by the AESO. The software accesses base-case load flow results, AESO seasonal energy volumes and loss estimates and user defined opportunity service transactions. The software determines compressed loss factors for generator and opportunity service transactions. The 'virtual load flow' estimate of losses and the loss factors for generators and opportunity services as presented in this report have all been calculated with the newly developed software.

Table 1 Impact of Imports/Exports on Losses

Import/Export MW		Losses (MW)											
		WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
BC	Sask Power	Import	Export	Export	Import	Export	Export	Import	Export	Export	Import	Export	Export
600	150	352.2	417.5	389.9	333.6	375.2	354.4	323.2	372.2	361.0	349.0	404.9	405.2
600	0	350.4	383.0	372.0	328.7	347.4	337.4	321.4	352.0	339.5	343.5	374.7	378.5
200	150	345.3	341.8	352.4	326.5	314.7	313.6	310.8	330.3	318.4	330.6	342.1	353.0
200	0	353.6	327.1	326.6	333.5	308.6	289.6	318.5	319.6	271.1	334.7	336.5	297.4
0	150	363.8	332.2	342.5	343.1	311.9	297.1	326.8	319.6	278.0	344.7	339.3	305.9
0	0	376.7	324.3	289.2	355.3	304.4	250.9	340.4	307.0	232.6	354.2	326.4	253.8

Import/Export MW		Actual Change in Losses From Base Cases (MW)											
		WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
BC	Sask Power	Import	Export	Export	Import	Export	Export	Import	Export	Export	Import	Export	Export
600	150	-24.5	93.2	100.7	-21.7	70.8	103.5	-17.3	65.2	128.4	-5.2	78.6	151.4
600	0	-26.3	58.7	82.8	-26.6	43.0	86.5	-19.1	45.0	106.9	-10.7	48.3	124.7
200	150	-31.4	17.5	63.2	-28.9	10.3	62.7	-29.6	23.3	85.8	-23.6	15.7	99.2
200	0	-23.1	2.8	37.3	-21.9	4.2	38.7	-22.0	12.5	38.5	-19.5	10.2	43.6
0	150	-12.9	7.9	53.2	-12.2	7.5	46.2	-13.6	12.6	45.3	-9.5	12.9	52.1

Table 2 Recovery of Losses with Loss Factors Based on Average of Actual Contribution to Losses

Import/Export MW		Assigned Change in Losses From Base Cases (MW)											
		WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
BC	Sask Power	Import	Export	Export	Import	Export	Export	Import	Export	Export	Import	Export	Export
600	150	-34.0	96.6	96.6	-34.0	96.6	96.6	-34.0	96.6	96.6	-34.0	96.6	96.6
600	0	-29.2	70.5	70.5	-29.2	70.5	70.5	-29.2	70.5	70.5	-29.2	70.5	70.5
200	150	-14.5	49.6	49.6	-14.5	49.6	49.6	-14.5	49.6	49.6	-14.5	49.6	49.6
200	0	-9.7	23.5	23.5	-9.7	23.5	23.5	-9.7	23.5	23.5	-9.7	23.5	23.5
0	150	-4.7	26.1	26.1	-4.7	26.1	26.1	-4.7	26.1	26.1	-4.7	26.1	26.1

Import/Export MW		Unassigned Change in Losses From Base Cases (MW)											
		WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
BC	Sask Power	Import	Export	Export	Import	Export	Export	Import	Export	Export	Import	Export	Export
600	150	-9.5	3.4	-4.2	-12.3	25.8	-7.0	-16.7	31.4	-31.8	-28.8	18.0	-54.8
600	0	-2.9	11.7	-12.3	-2.6	27.5	-16.0	-10.2	25.5	-36.4	-18.6	22.2	-54.2
200	150	16.9	32.0	-13.6	14.4	39.3	-13.1	15.1	26.3	-36.2	9.1	33.9	-49.6
200	0	13.3	20.7	-13.8	12.1	19.3	-15.2	12.2	11.0	-15.0	9.8	13.3	-20.1
0	150	8.2	18.2	-27.2	7.5	18.6	-20.1	8.9	13.5	-19.3	4.8	13.1	-26.0

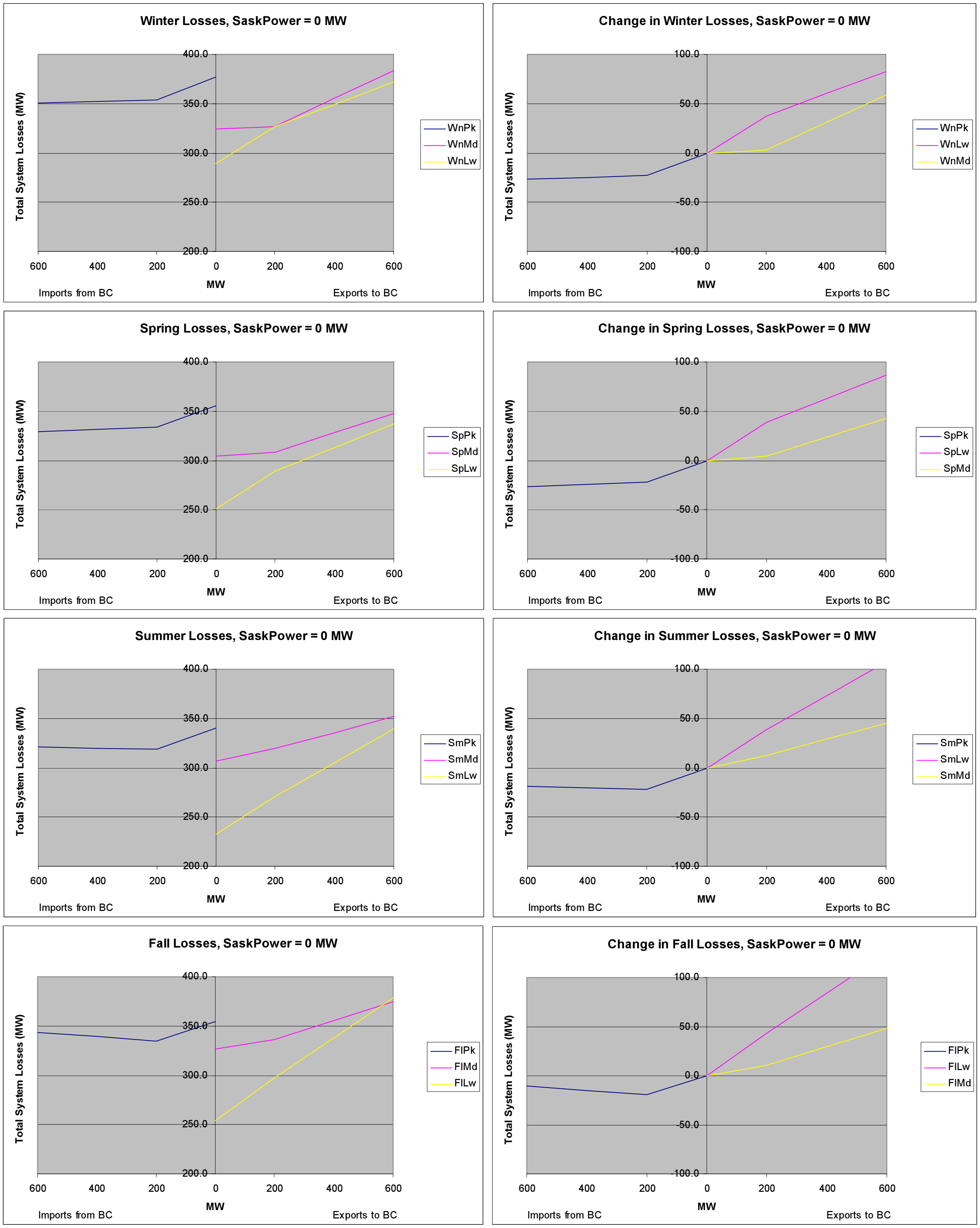

Figure 1 Variation of Losses with Imports from and Exports to BC, No SaskPower Interchange

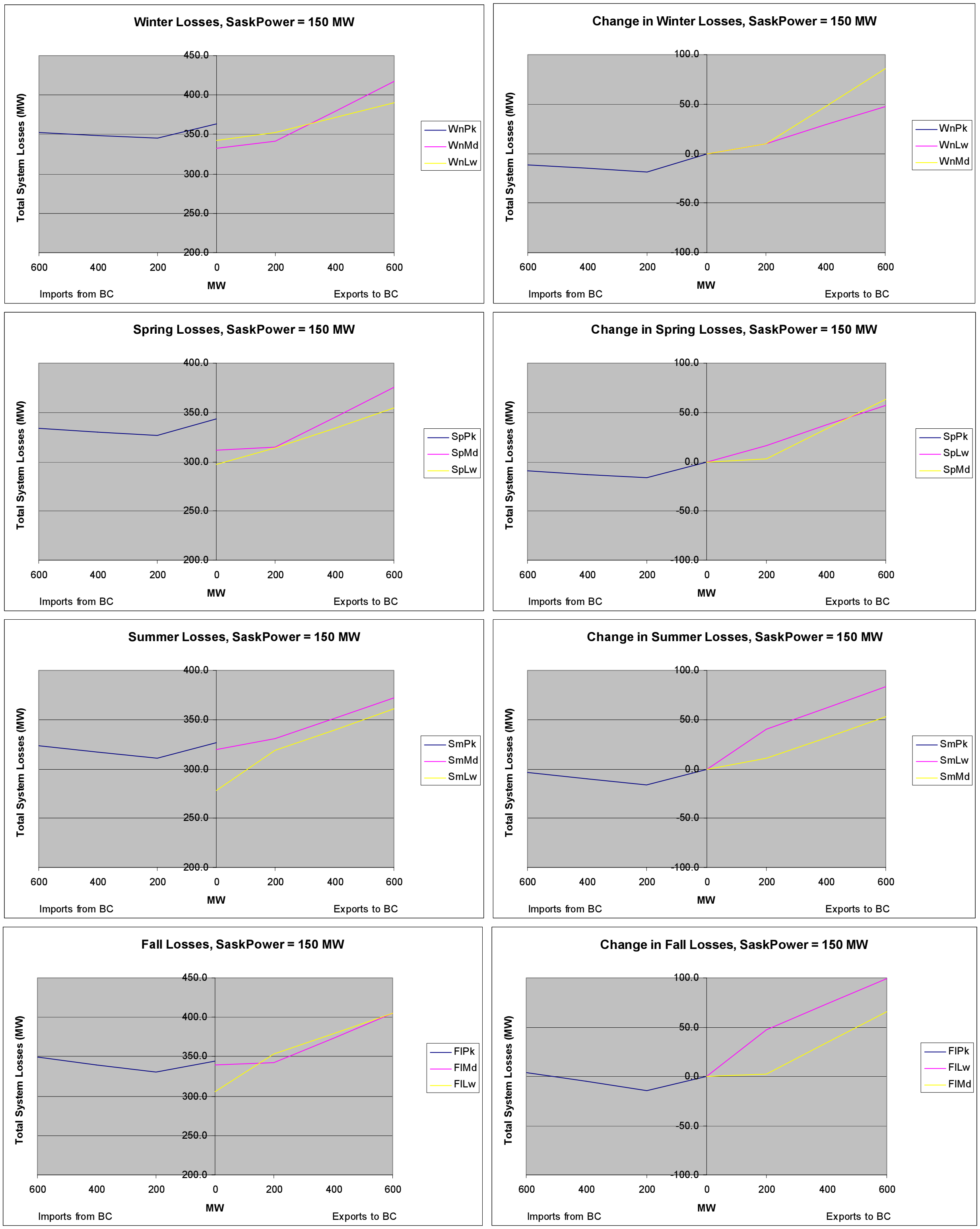

Figure 2 Variation of Losses with Imports from and Exports to BC, 150 MW SaskPower Interchange

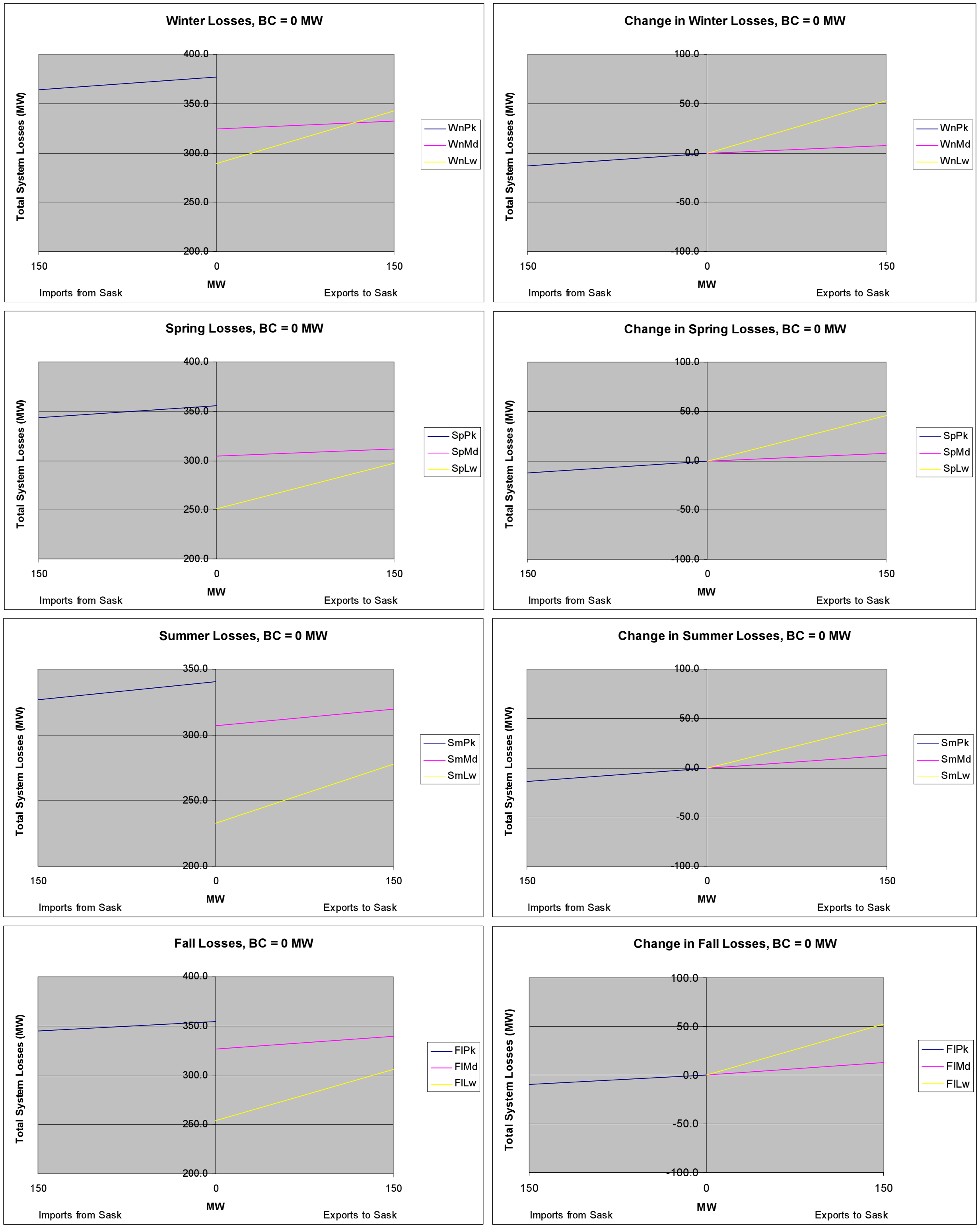

Figure 3 Variation of Losses with Imports from and Exports to SaskPower, No BC Interchange

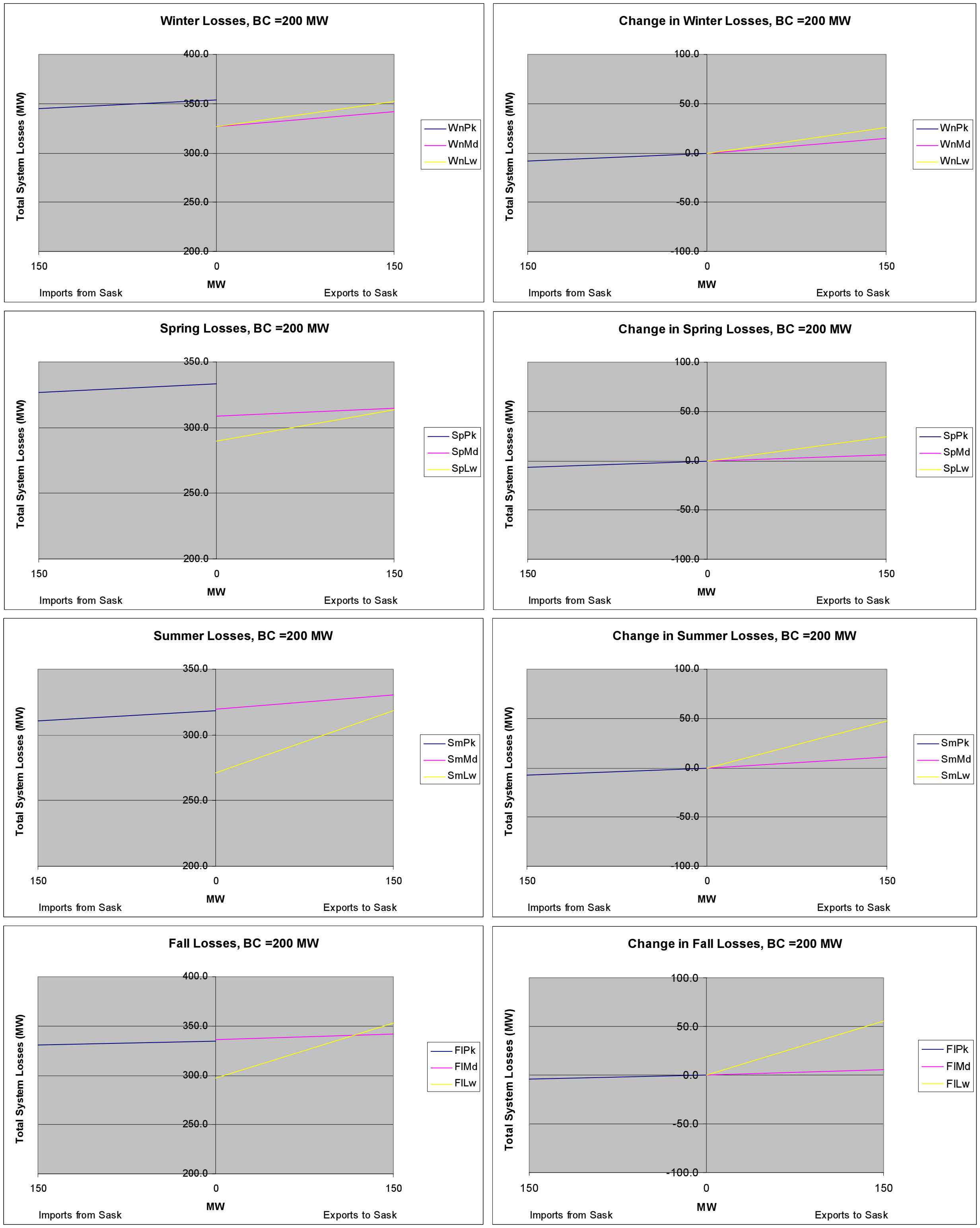

Figure 4 Variation of Losses with Imports from and Exports to SaskPower, 200 MW BC Interchange

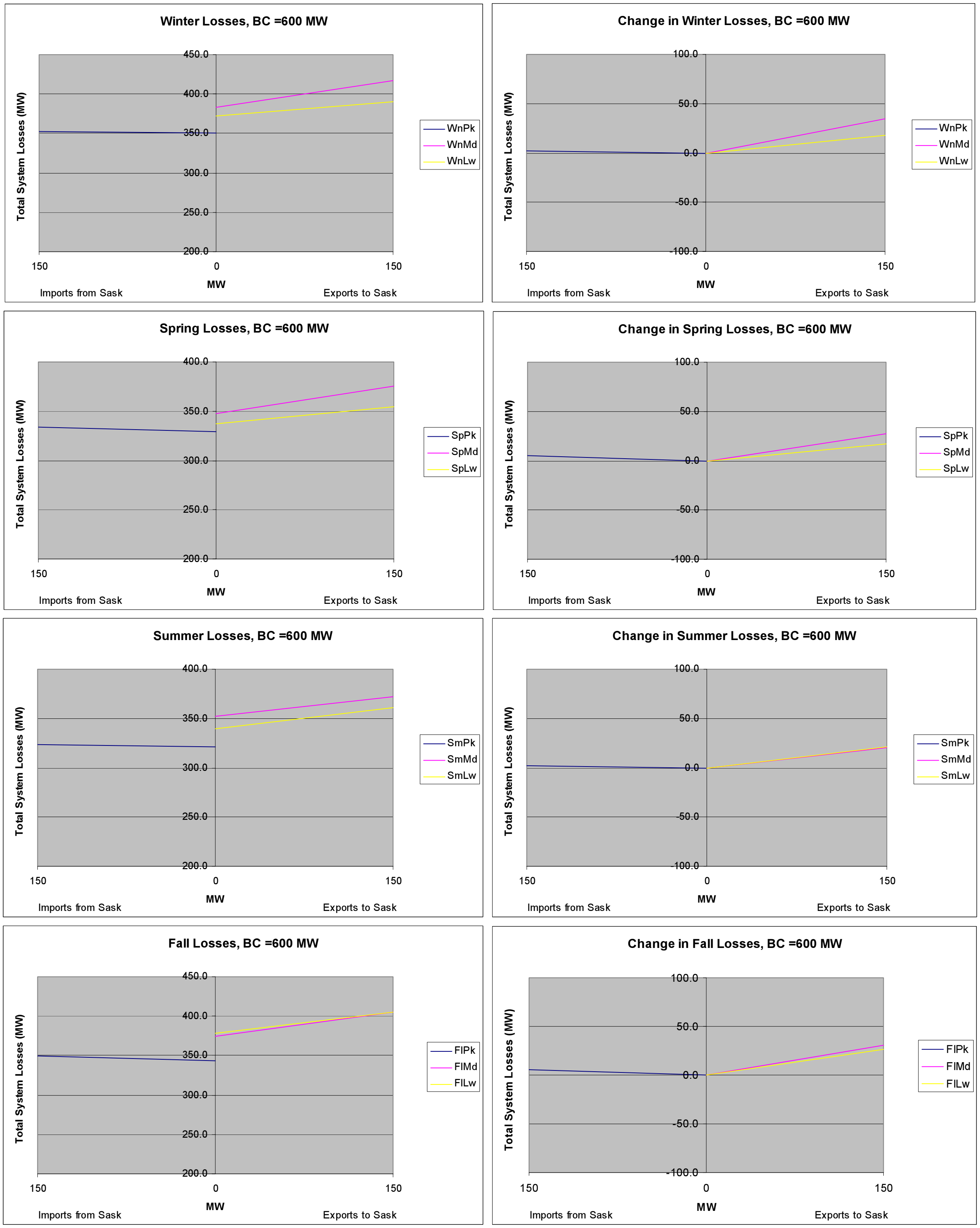

Figure 5 Variation of Losses with Imports from and Exports to SaskPower, 600 MW BC Interchange

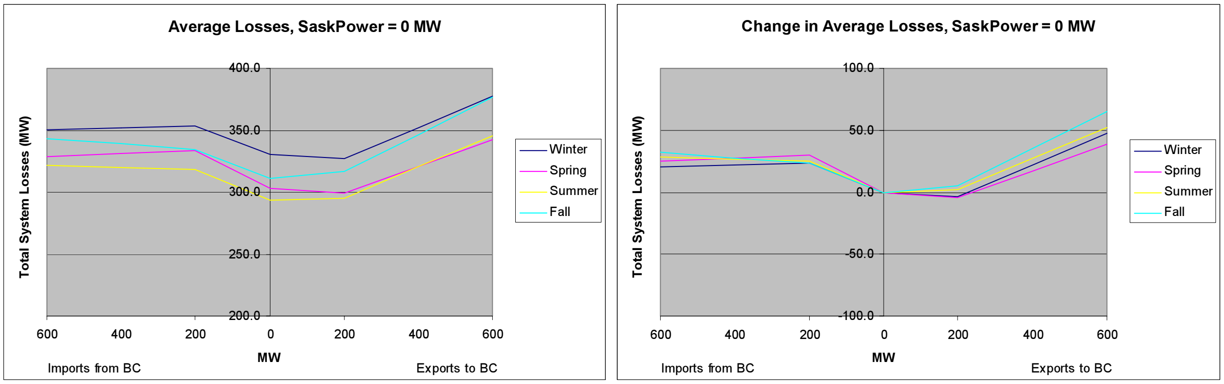

Figure 6 Variation of Average Losses, No SaskPower Interchange

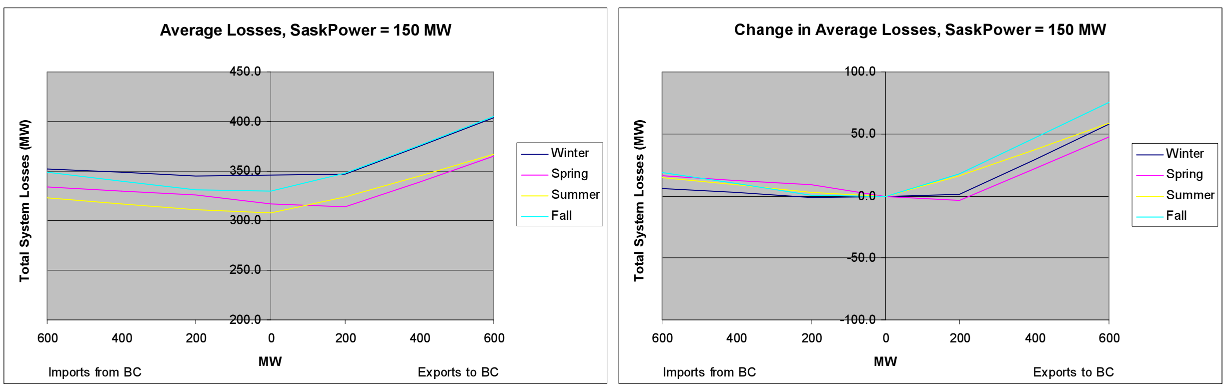

Figure 7 Variation of Average Losses, 150 MW SaskPower Interchange

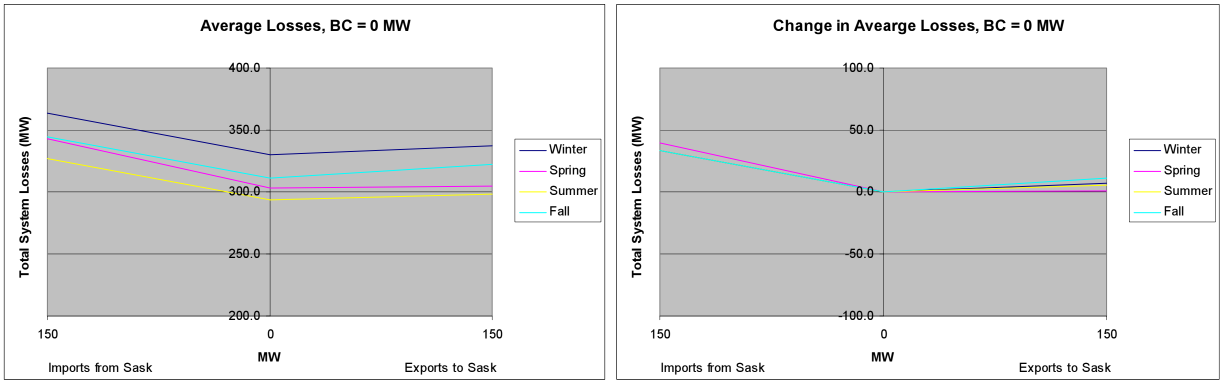

Figure 8 Variation of Average Losses, No BC Interchange

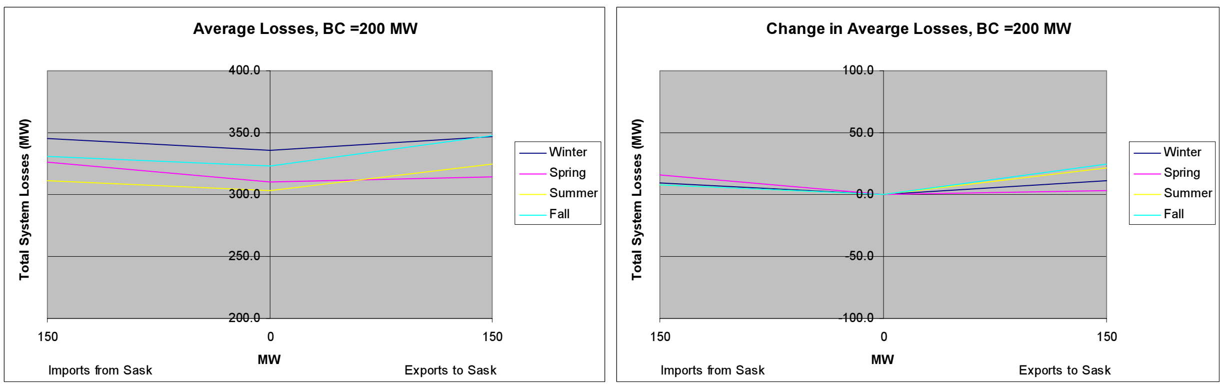

Figure 9 Variation of Average Losses, 200 MW BC Interchange

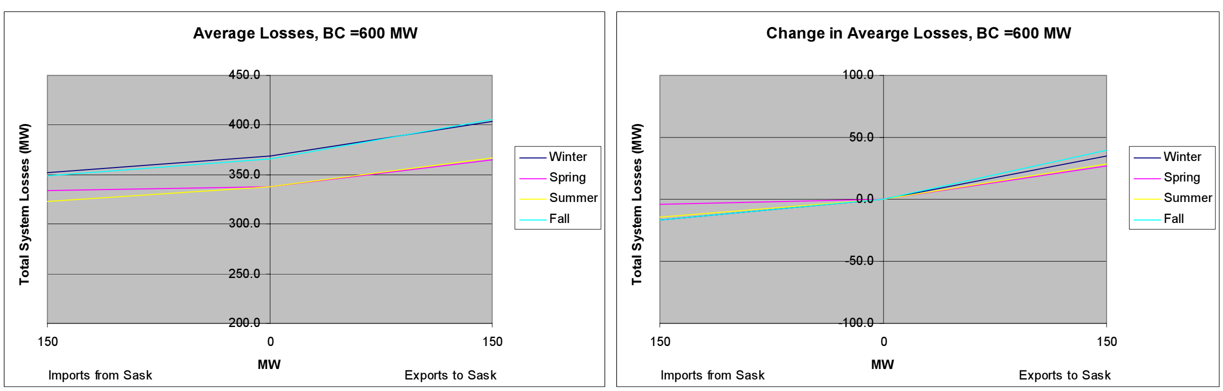

Figure 10 Variation of Average Losses, 600 MW BC Interchange

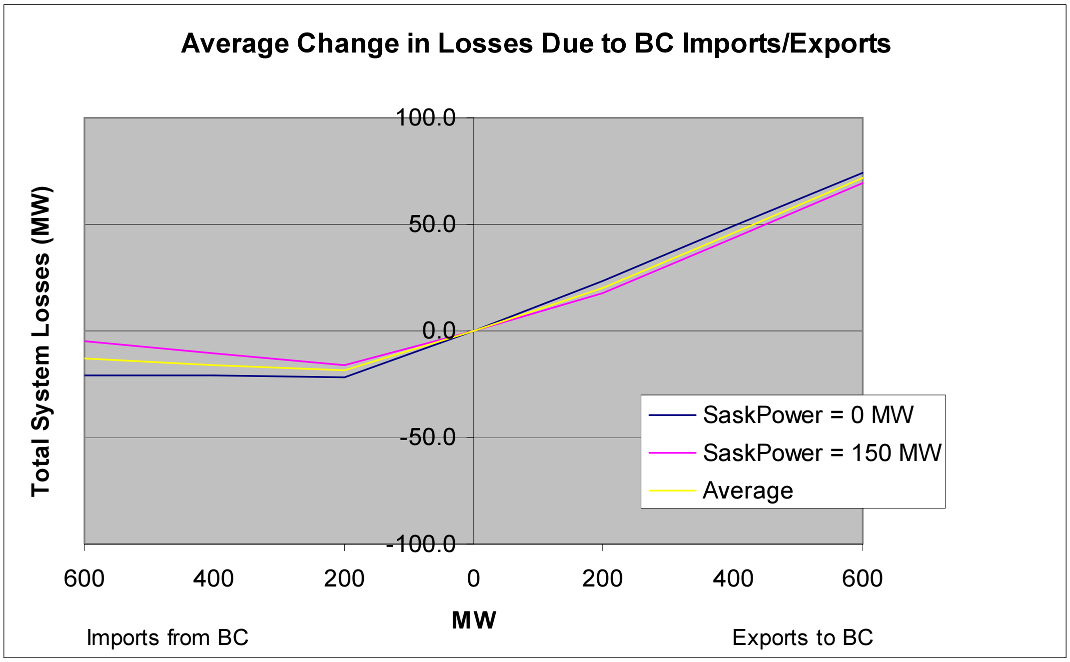

Figure 11 Average Change in Losses Due to BC Imports and Exports

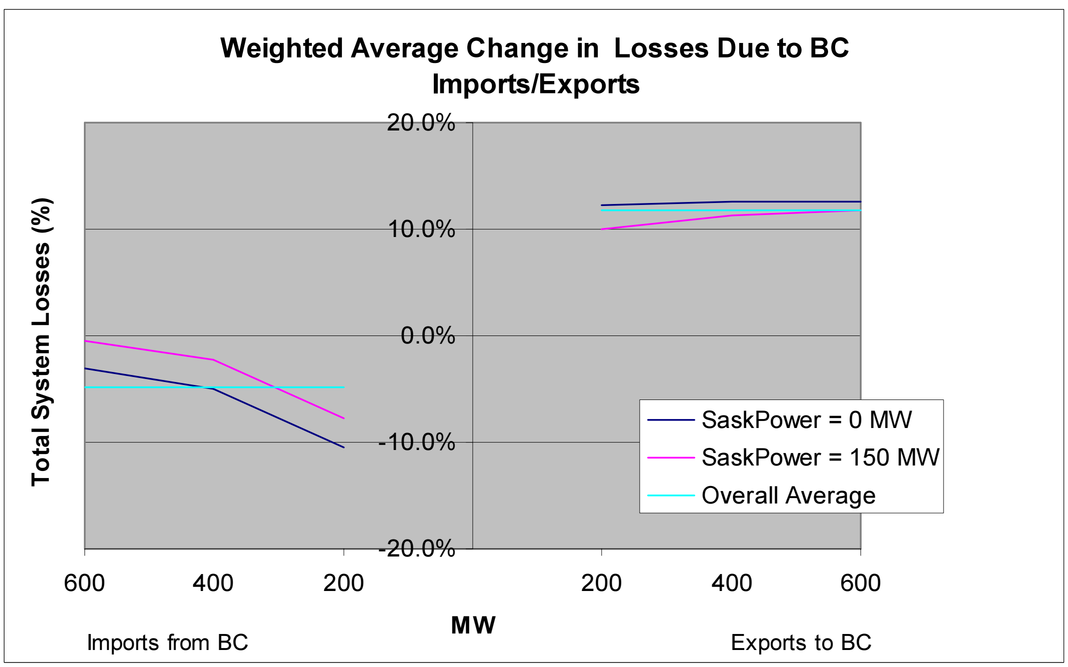

Figure 12 Average 'Incremental' Loss Factor Due to BC Imports and Exports

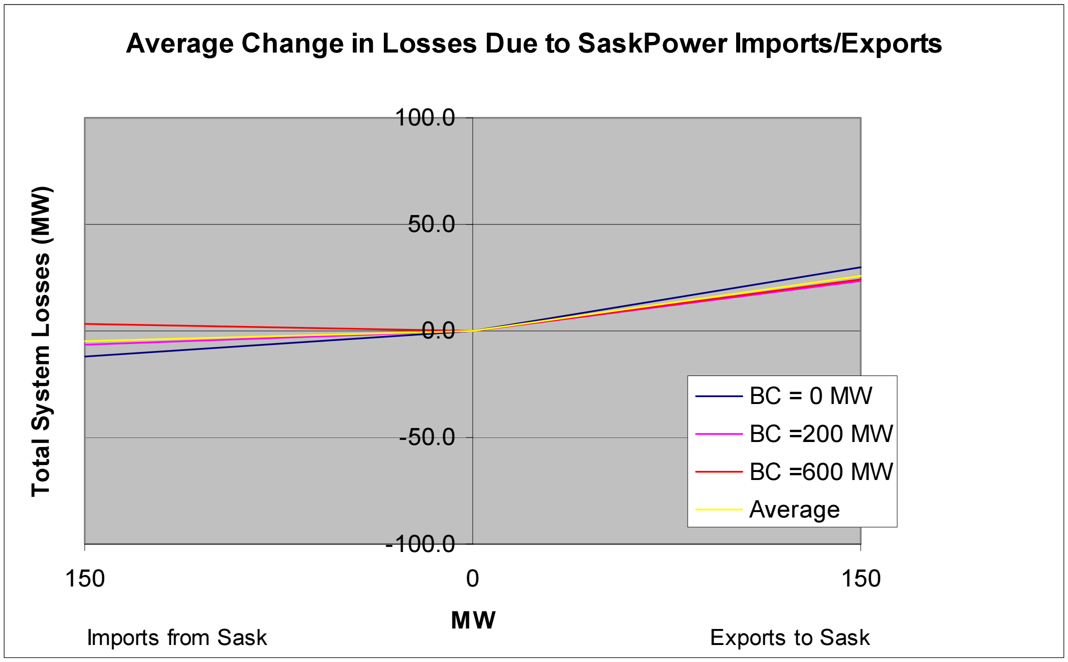

Figure 13 Average Change in Losses Due to SaskPower Imports and Exports

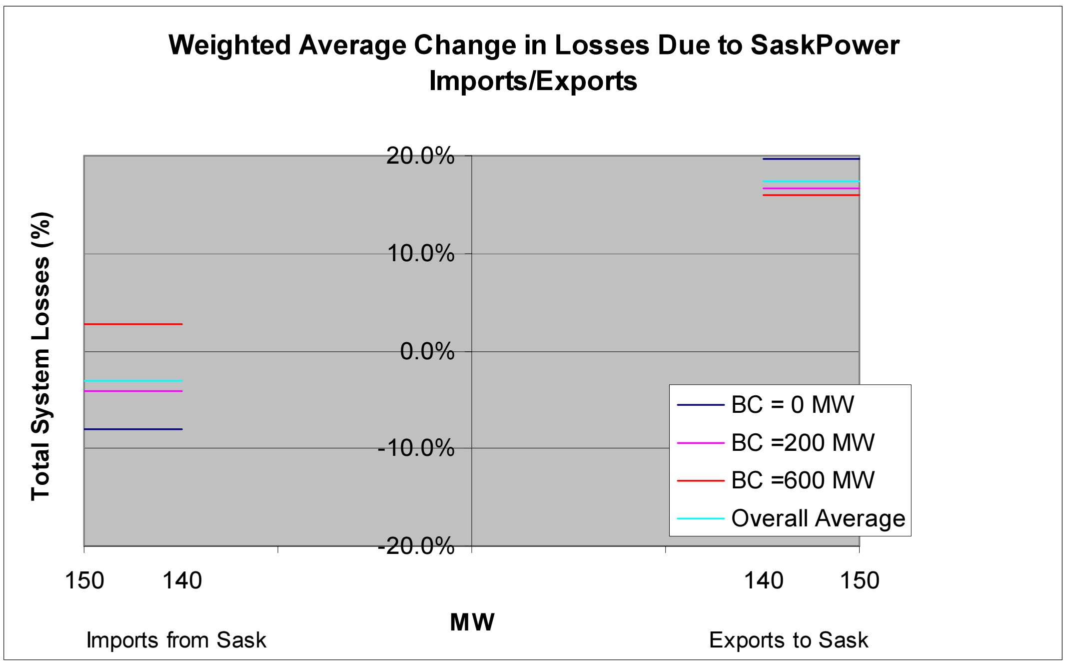

Figure 14 Average 'Incremental' Loss Factor Due to SaskPower Imports and Exports

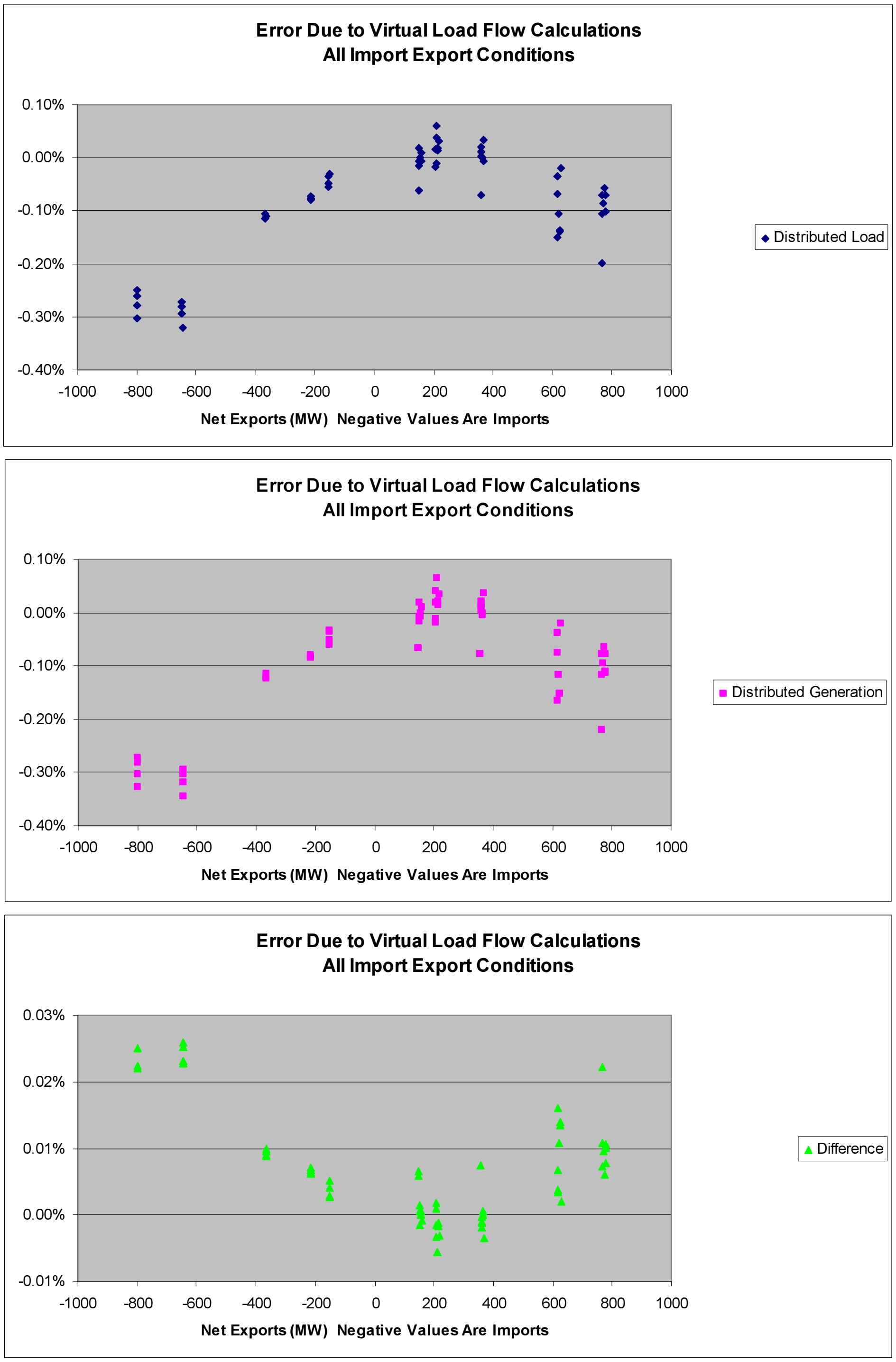

Figure 15 Errors Due to Virtual Load Flows, with Generator Balancing

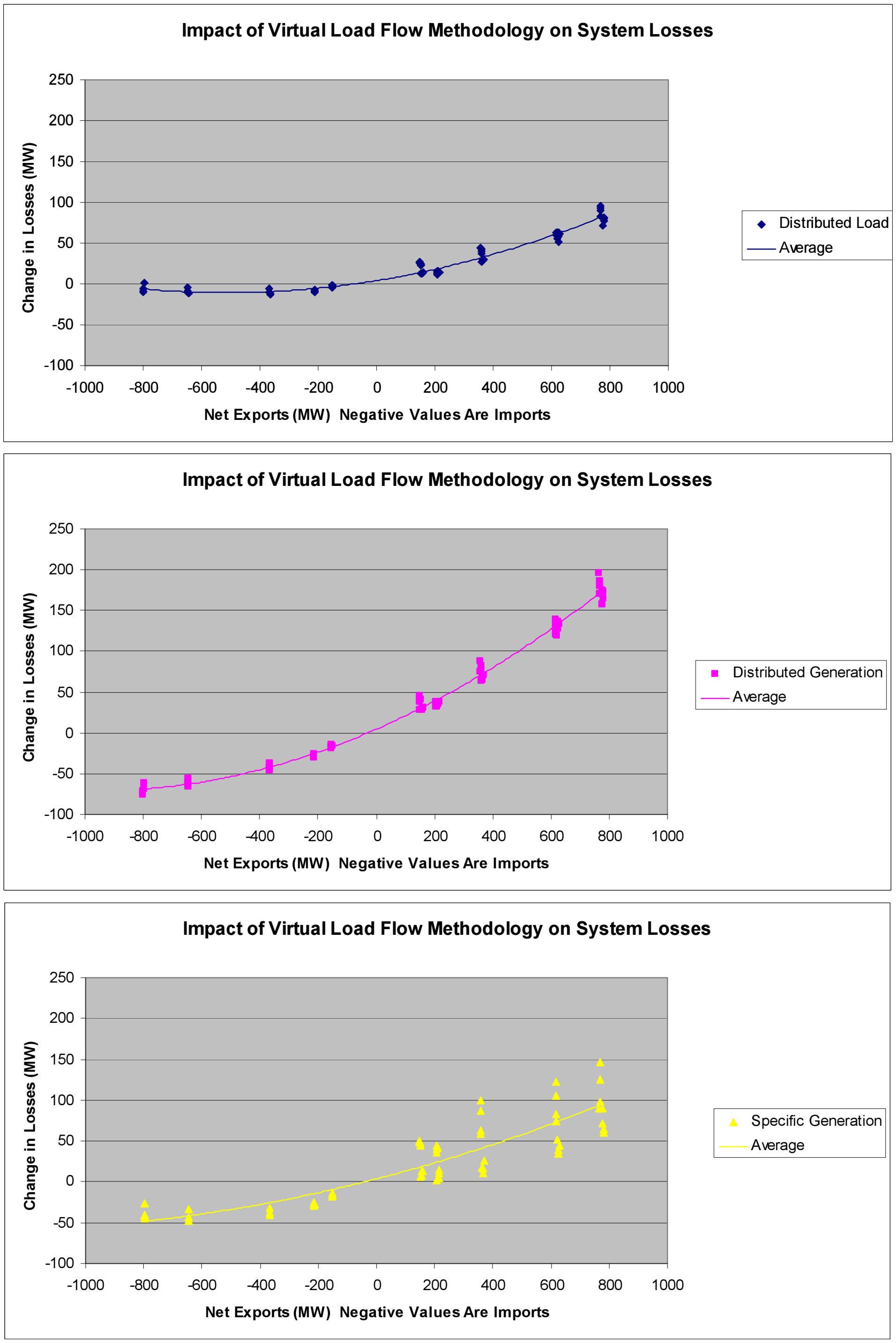

Figure 16 Impact of Virtual Load Flow Methodology on System Losses

Appendix A

Calculation of Surplus/Shortfall for Each Load Flow Condition

	Loss Factors	
Sask	Imports	-3.72%
	Exports	18.21%
BC	Imports	-1.92%
	Exports	10.11%

	Base Case					Change Case					Base Case					Change Case					Base Case Losses						Change Case Losses						
		SPC					SPC					BC					BC																
	MW	Import or Export	Imp MW	Exp MW	loss factor %	MW	Import or Export	Imp MW	Exp MW	loss factor %	MW	Import or Export	Imp MW	Exp MW	loss factor %	MW	Import or Export	Imp MW	Exp MW	loss factor %	Actual Losses MW	To Gen-erators MW	To Sask MW	To BC MW	Allocat-ed MW	Mis-match MW	Actual Losses MW	To Gen-erators MW	To Sask MW	To BC MW	Allocat-ed MW	Mis-match MW	Surplus MW
Peak (Import)																																	
Winter Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.94	Import	35.94		-1.92%	39.07	Import	39.07		-1.92%	377.22	374.44	0.00	-0.69	373.75	-3.47	364.02	365.56	-5.58	-0.75	359.23	-4.79	-1.32
Spring Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.78	Import	35.78		-1.92%	36.63	Import	36.63		-1.92%	355.96	359.41	0.00	-0.69	358.72	2.76	343.43	350.81	-5.58	-0.70	344.52	1.09	-1.67
Summer Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.95	Import	35.95		-1.92%	38.31	Import	38.31		-1.92%	340.81	353.17	0.00	-0.69	352.48	11.67	327.03	344.30	-5.58	-0.74	337.98	10.95	-0.72
Fall peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	38.62	Import	38.62		-1.92%	41.08	Import	41.08		-1.92%	354.67	364.65	0.00	-0.74	363.91	9.24	344.88	356.01	-5.58	-0.79	349.64	4.76	-4.48
Medium (Export)																																	
Winter Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.31	Import	29.31		-1.92%	28.24	Import	28.24		-1.92%	324.55	341.93	0.00	-0.56	341.37	16.82	332.44	340.73	27.32	-0.54	367.51	35.06	18.24
Spring Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.23	Import	39.23		-1.92%	32.76	Import	32.76		-1.92%	304.72	325.65	0.00	-0.75	324.89	20.18	312.16	325.62	27.32	-0.63	352.32	40.15	19.97
Summer Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	38.83	Import	38.83		-1.92%	28.91	Import	28.91		-1.92%	307.23	322.06	0.00	-0.75	321.32	14.09	319.71	323.73	27.32	-0.55	350.50	30.79	16.70
Fall Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.97	Import	39.97		-1.92%	33.90	Import	33.90		-1.92%	326.60	336.62	0.00	-0.77	335.85	9.26	339.40	338.61	27.32	-0.65	365.28	25.88	16.62
Low (Export)																																	
Winter Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.85	Import	31.85		-1.92%	33.09	Import	33.09		-1.92%	289.64	310.30	0.00	-0.61	309.69	20.05	342.69	323.72	27.32	-0.64	350.41	7.72	-12.33
Spring Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.51	Import	31.51		-1.92%	29.68	Import	29.68		-1.92%	251.16	288.73	0.00	-0.60	288.13	36.97	297.28	302.54	27.32	-0.57	329.29	32.01	-4.96
Summer Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.84	Import	29.84		-1.92%	29.22	Import	29.22		-1.92%	232.79	274.11	0.00	-0.57	273.54	40.75	278.12	288.06	27.32	-0.56	314.82	36.69	-4.06
Fall Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	34.29	Import	34.29		-1.92%	35.29	Import	35.29		-1.92%	254.04	285.85	0.00	-0.66	285.20	31.15	305.99	300.15	27.32	-0.68	326.80	20.81	-10.34
Peak (Import)																																	
Winter Peak	0.00	none			0.00%	0.00	none			0.00%	35.94	Import	35.94		-1.92%	682.63	Import	682.63		-1.92%	377.22	374.44	0.00	-0.69	373.75	-3.47	350.58	343.29	0.00	-13.10	330.19	-20.40	-16.93
Spring Peak	0.00	none			0.00%	0.00	none			0.00%	35.78	Import	35.78		-1.92%	682.16	Import	682.16		-1.92%	355.96	359.41	0.00	-0.69	358.72	2.76	328.96	326.66	0.00	-13.09	313.57	-15.40	-18.15
Summer Peak	0.00	none			0.00%	0.00	none			0.00%	35.95	Import	35.95		-1.92%	681.86	Import	681.86		-1.92%	340.81	353.17	0.00	-0.69	352.48	11.67	321.58	323.65	0.00	-13.09	310.57	-11.02	-22.69
Fall peak	0.00	none			0.00%	0.00	none			0.00%	38.62	Import	38.62		-1.92%	684.98	Import	684.98		-1.92%	354.67	364.65	0.00	-0.74	363.91	9.24	343.78	336.18	0.00	-13.15	323.03	-20.75	-29.99
Medium (Export)																																	
Winter Medium	0.00	none			0.00%	0.00	none			0.00%	29.31	Import	29.31		-1.92%	-592.91	Export		592.91	10.11%	324.55	341.93	0.00	-0.56	341.37	16.82	383.29	354.55	0.00	59.96	414.51	31.22	14.40
Spring Medium	0.00	none			0.00%	0.00	none			0.00%	39.23	Import	39.23		-1.92%	-586.73	Export		586.73	10.11%	304.72	325.65	0.00	-0.75	324.89	20.18	347.67	328.78	0.00	59.33	388.11	40.45	20.27
Summer Medium	0.00	none			0.00%	0.00	none			0.00%	38.83	Import	38.83		-1.92%	-589.60	Export		589.60	10.11%	307.23	322.06	0.00	-0.75	321.32	14.09	352.20	326.31	0.00	59.62	385.94	33.74	19.65
Fall Medium	0.00	none			0.00%	0.00	none			0.00%	39.97	Import	39.97		-1.92%	-585.69	Export		585.69	10.11%	326.60	336.62	0.00	-0.77	335.85	9.26	374.81	339.49	0.00	59.23	398.71	23.90	14.65
Low (Export)																																	
Winter Low	0.00	none			0.00%	0.00	none			0.00%	31.85	Import	31.85		-1.92%	-584.40	Export		584.40	10.11%	289.64	310.30	0.00	-0.61	309.69	20.05	372.20	337.66	0.00	59.10	396.76	24.56	4.51
Spring Low	0.00	none			0.00%	0.00	none			0.00%	31.51	Import	31.51		-1.92%	-585.02	Export		585.02	10.11%	251.16	288.73	0.00	-0.60	288.13	36.97	337.58	318.72	0.00	59.16	377.88	40.30	3.33
Summer Low	0.00	none			0.00%	0.00	none			0.00%	29.84	Import	29.84		-1.92%	-588.25	Export		588.25	10.11%	232.79	274.11	0.00	-0.57	273.54	40.75	339.65	313.50	0.00	59.49	372.99	33.34	-7.42
Fall Low	0.00	none			0.00%	0.00	none			0.00%	34.29	Import	34.29		-1.92%	-584.08	Export		584.08	10.11%	254.04	285.85	0.00	-0.66	285.20	31.15	378.62	328.91	0.00	59.07	387.97	9.35	-21.80
Peak (Import)																																	
Winter Peak	0.00	none			0.00%	0.00	none			0.00%	35.94	Import	35.94		-1.92%	249.89	Import	249.89		-1.92%	377.22	374.44	0.00	-0.69	373.75	-3.47	353.84	368.51	0.00	-4.80	363.71	9.87	13.34
Spring Peak	0.00	none			0.00%	0.00	none			0.00%	35.78	Import	35.78		-1.92%	248.97	Import	248.97		-1.92%	355.96	359.41	0.00	-0.69	358.72	2.76	333.77	353.67	0.00	-4.78	348.89	15.13	12.37
Summer Peak	0.00	none			0.00%	0.00	none			0.00%	35.95	Import	35.95		-1.92%	248.99	Import	248.99		-1.92%	340.81	353.17	0.00	-0.69	352.48	11.67	318.71	347.33	0.00	-4.78	342.55	23.84	12.17
Fall peak	0.00	none			0.00%	0.00	none			0.00%	38.62	Import	38.62		-1.92%	252.12	Import	252.12		-1.92%	354.67	364.65	0.00	-0.74	363.91	9.24	334.91	359.02	0.00	-4.84	354.18	19.26	10.02
Medium (Export)																																	
Winter Medium	0.00	none			0.00%	0.00	none			0.00%	29.31	Import	29.31		-1.92%	-178.88	Export		178.88	10.11%	324.55	341.93	0.00	-0.56	341.37	16.82	327.32	335.37	0.00	18.09	353.46	26.14	9.32
Spring Medium	0.00	none			0.00%	0.00	none			0.00%	39.23	Import	39.23		-1.92%	-175.60	Export		175.60	10.11%	304.72	325.65	0.00	-0.75	324.89	20.18	308.80	320.51	0.00	17.76	338.27	29.46	9.28
Summer Medium	0.00	none			0.00%	0.00	none			0.00%	38.83	Import	38.83		-1.92%	-178.14	Export		178.14	10.11%	307.23	322.06	0.00	-0.75	321.32	14.09	319.66	320.45	0.00	18.01	338.46	18.80	4.71
Fall Medium	0.00	none			0.00%	0.00	none			0.00%	39.97	Import	39.97		-1.92%	-173.87	Export		173.87	10.11%	326.60	336.62	0.00	-0.77	335.85	9.26	336.63	333.54	0.00	17.58	351.12	14.49	5.23
Low (Export)																																	
Winter Low	0.00	none			0.00%	0.00	none			0.00%	31.85	Import	31.85		-1.92%	-174.83	Export		174.83	10.11%	289.64	310.30	0.00	-0.61	309.69	20.05	326.77	320.27	0.00	17.68	337.95	11.18	-8.87
Spring Low	0.00	none			0.00%	0.00	none			0.00%	31.51	Import	31.51		-1.92%	-177.76	Export		177.76	10.11%	251.16	288.73	0.00	-0.60	288.13	36.97	289.84	300.89	0.00	17.98	318.87	29.03	-7.94
Summer Low	0.00	none			0.00%	0.00	none			0.00%	29.84	Import	29.84		-1.92%	-177.67	Export		177.67	10.11%	232.79	274.11	0.00	-0.57	273.54	40.75	271.23	286.84	0.00	17.97	304.81	33.58	-7.18
Fall Low	0.00	none			0.00%	0.00	none			0.00%	34.29	Import	34.29		-1.92%	-172.12	Export		172.12	10.11%	254.04	285.85	0.00	-0.66	285.20	31.15	297.58	299.01	0.00	17.41	316.42	18.85	-12.31
Peak (Import)																																	
Winter Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.94	Import	35.94		-1.92%	251.61	Import	251.61		-1.92%	377.22	374.44	0.00	-0.69	373.75	-3.47	345.56	365.92	-5.58	-4.83	355.51	9.94	13.41
Spring Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.78	Import	35.78		-1.92%	251.97	Import	251.97		-1.92%	355.96	359.41	0.00	-0.69	358.72	2.76	326.77	351.12	-5.58	-4.84	340.70	13.93	11.17
Summer Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.95	Import	35.95		-1.92%	251.27	Import	251.27		-1.92%	340.81	353.17	0.00	-0.69	352.48	11.67	310.99	344.75	-5.58	-4.82	334.34	23.35	11.68
Fall peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	38.62	Import	38.62		-1.92%	255.06	Import	255.06		-1.92%	354.67	364.65	0.00	-0.74	363.91	9.24	330.85	356.62	-5.58	-4.90	346.14	15.28	6.04
Medium (Export)																																	
Winter Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.31	Import	29.31		-1.92%	-182.17	Export		182.17	10.11%	324.55	341.93	0.00	-0.56	341.37	16.82	342.03	332.23	27.32	18.42	377.97	35.94	19.12
Spring Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.23	Import	39.23		-1.92%	-176.47	Export		176.47	10.11%	304.72	325.65	0.00	-0.75	324.89	20.18	314.93	313.22	27.32	17.85	358.39	43.46	23.28
Summer Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	38.83	Import	38.83		-1.92%	-180.40	Export		180.40	10.11%	307.23	322.06	0.00	-0.75	321.32	14.09	330.40	314.93	27.32	18.24	360.49	30.09	16.00
Fall Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.97	Import	39.97		-1.92%	-175.32	Export		175.32	10.11%	326.60	336.62	0.00	-0.77	335.85	9.26	342.18	326.45	27.32	17.73	371.50	29.32	20.06
Low (Export)																																	
Winter Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.85	Import	31.85		-1.92%	-175.97	Export		175.97	10.11%	289.64	310.30	0.00	-0.61	309.69	20.05	352.63	319.84	27.32	17.80	364.95	12.32	-7.73
Spring Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.51	Import	31.51		-1.92%	-177.83	Export		177.83	10.11%	251.16	288.73	0.00	-0.60	288.13	36.97	313.77	300.20	27.32	17.98	345.51	31.73	-5.23
Summer Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.84	Import	29.84		-1.92%	-179.33	Export		179.33	10.11%	232.79	274.11	0.00	-0.57	273.54	40.75	318.57	293.83	27.32	18.13	339.29	20.72	-20.04
Fall Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	34.29	Import	34.29		-1.92%	-175.55	Export		175.55	10.11%	254.04	285.85	0.00	-0.66	285.20	31.15	353.15	307.73	27.32	17.75	352.80	-0.35	-31.50
Peak (Import)																																	
Winter Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.94	Import	35.94		-1.92%	684.41	Import	684.41		-1.92%	377.22	374.44	0.00	-0.69	373.75	-3.47	352.36	365.42	-5.58	-13.14	346.70	-5.65	-2.19
Spring Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.78	Import	35.78		-1.92%	684.11	Import	684.11		-1.92%	355.96	359.41	0.00	-0.69	358.72	2.76	333.91	347.18	-5.58	-13.13	328.47	-5.44	-8.20
Summer Peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	35.95	Import	35.95		-1.92%	684.70	Import	684.70		-1.92%	340.81	353.17	0.00	-0.69	352.48	11.67	323.42	346.57	-5.58	-13.14	327.85	4.43	-7.24
Fall peak	0.00	none			0.00%	150.00	Import	150.00		-3.72%	38.62	Import	38.62		-1.92%	686.44	Import	686.44		-1.92%	354.67	364.65	0.00	-0.74	363.91	9.24	349.24	360.74	-5.58	-13.18	341.98	-7.26	-16.50
Medium (Export)																																	
Winter Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.31	Import	29.31		-1.92%	-596.43	Export		596.43	10.11%	324.55	341.93	0.00	-0.56	341.37	16.82	417.77	342.66	27.32	60.31	430.29	12.53	-4.29
Spring Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.23	Import	39.23		-1.92%	-589.89	Export		589.89	10.11%	304.72	325.65	0.00	-0.75	324.89	20.18	375.51	316.69	27.32	59.65	403.66	28.16	7.98
Summer Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	38.83	Import	38.83		-1.92%	-591.46	Export		591.46	10.11%	307.23	322.06	0.00	-0.75	321.32	14.09	372.34	307.72	27.32	59.81	394.85	22.51	8.42
Fall Medium	0.00	none			0.00%	-150.00	Export		150.00	18.21%	39.97	Import	39.97		-1.92%	-588.47	Export		588.47	10.11%	326.60	336.62	0.00	-0.77	335.85	9.26	405.03	327.54	27.32	59.51	414.37	9.34	0.08
Low (Export)																																	
Winter Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.85	Import	31.85		-1.92%	-584.45	Export		584.45	10.11%	289.64	310.30	0.00	-0.61	309.69	20.05	390.15	319.05	27.32	59.10	405.48	15.33	-4.72
Spring Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	31.51	Import	31.51		-1.92%	-585.96	Export		585.96	10.11%	251.16	288.73	0.00	-0.60	288.13	36.97	354.64	300.07	27.32	59.26	386.65	32.01	-4.96
Summer Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	29.84	Import	29.84		-1.92%	-588.84	Export		588.84	10.11%	232.79	274.11	0.00	-0.57	273.54	40.75	361.07	295.95	27.32	59.55	382.81	21.75	-19.00
Fall Low	0.00	none			0.00%	-150.00	Export		150.00	18.21%	34.29	Import	34.29		-1.92%	-585.39	Export		585.39	10.11%	254.04	285.85	0.00	-0.66	285.20	31.15	405.31	312.63	27.32	59.20	399.15	-6.16	-37.31

Condition	No. of Cases	Average Surplus
Imports From Sask	12	0.00
Exports to Sask	24	0.00
Imports from BC	28	0.00
Exports to BC	32	0.00
All cases	60	0.00
BC approx 200 MW	24	4.02
BC approx 600 MW	24	-5.34
Peak	20	-1.99
Medium	20	12.99
Low	20	-10.99

Maximum Surplus	23.28
Minimum Surplus	-37.31

Appendix B

Algorithm for the Calculation of Import Export Loss Factors

Appendix B

Algorithm for the Calculation of Import Export Loss Factors

The proposed methodology for the calculation of loss factors for imports and exports is a multi-step process.

The set of twelve base case load flows as used in the calculation of generator loss factors will be used as starting conditions for the calculation of import and export loss factors. The base cases have been developed on the assumption of no net flow across each intertie. For the BC intertie, the net flow includes the 500 kV connection from Langdon as well as the 138 kV connections from Pocaterra and Coleman. Each point of connection for each intertie eventually will be represented in the base case load flows as a radial negative (export) or positive (import) generator. There may be circulating flows through these points of connection but the net flow will be close to zero. The proposed methodology will handle additional connection points to each of the interties as well as additional intertie locations and directions of flow from the Alberta System.

The change in Alberta system losses will be determined for several representative operating conditions. It is expected that these will include:

- For peak load conditions, import of 200 from BC, import of 600 MW from BC, import of 150 MW from Saskatchewan, simultaneous import of 200 MW from BC and 150 MW from Sask., simultaneous import of 600 MW from BC and 150 MW from Sask.

- For medium and low load conditions, export of 200 to BC, export of 600 MW to BC, export of 75 MW to Saskatchewan, simultaneous export of 200 MW to BC and 75 MW to Sask., simultaneous export of 600 MW to BC and 75 MW to Sask.

The loss variation cases above can be expanded and modified as required based on future expected loading patterns. Additional interties could be added along with variations such as for example simultaneous import/export conditions from say Sask. to BC, imports on two interties exports on a third, etc.

It is proposed that the losses for each of the cases will be determined using a virtual load flow based on the R-Matrices developed for the generator loss factor calculations. For each virtual load flow, two simultaneous equations are solved:

$$\Delta L = \mathbf{\Delta \vec{P}}^{T} \mathbf{R \Delta \vec{P}} \qquad \text{Equation (1)}$$

$$\Delta L = \sum_i \Delta P_i \qquad \text{Equation (2)}$$

ΔL is the total change in system losses as a result of the imports and/or exports
R is the R-Matrix developed for the base case load flow
$\mathbf{\Delta\vec{P}}$ is a vector of changes in power injections at each affected bus in the system
ΔP_i is the change in power injection at the ith bus in the system

The injection change vector $\mathbf{\Delta\vec{P}}$ for each of the variation cases could be based on 'real' load flows carried out by the AESO. I.e. each import or export transaction could be based on the marginal unit of the GSO. A total of 60 load flow cases would need to be solved for the conditions listed above and the changes in injections transcribed from the load flow solution to the 'virtual' load flow solution. As the virtual load flow solution to Equation 1 and 2 is only approximate, the slack generation required to balance the virtual load flow could be distributed to all of the remaining generators in the Alberta system or distributed to system load. This procedure would require some interface to the generic stacking order to carry the calculations out efficiently.

An alternative methodology is proposed where the power change vector consists of only changes to intertie flows. All of the loads in the Alberta system would be adjusted to accommodate the export or import. The load adjustment factor is calculated using the same algorithm as used in the determination of generator 'raw' loss factors.

The disadvantage of this methodology is that the resultant virtual load flows would be more theoretical and less representative of specific operating conditions. The major advantage of this methodology is that the procedure for setting up data is much simplified, less subject to transcription inaccuracies and would not cause specific problems associated with transmission constraints associated with moving power from the next available generators in the GSO to the export (or import facility). This will become even more attractive if a third (or more) intertie is added. Each intertie could increase the number of load flow conditions that must be evaluated by a factor equal to the number of new intertie loading conditions. A new intertie with four loading conditions to be considered would increase the number of representative load flows from 60 to 240.

Once the change in losses has been determined for each of the 'virtual' load flow conditions, a set of individual import and export loss factors are determined for each facility that is 'revenue neutral' to the AESO. The loss factors assigned to the intertie will be such that loss charges (or credits) to the intertie and additional loss charges (or credits) to generators to supply the power to the interties will match the total losses resulting from the transaction. For each loading condition, the following equation can be applied:

$$\begin{aligned}\Delta L = &(\mathbf{P}_{\mathbf{interie}_{\text{change}}} - \mathbf{P}_{\mathbf{interie}_{\text{base}}})^{T} \cdot \mathbf{Lf}_{\mathbf{intertie}} \\ &+ (\mathbf{P}_{\mathbf{gen}_{\text{change}}} - \mathbf{P}_{\mathbf{gen}_{\text{base}}})^{T} \cdot \mathbf{Lf}_{\mathbf{gen}}\end{aligned} \qquad \text{Equation (3)}$$

ΔL is the total change in system losses as a result of the imports and/or exports

$\mathbf{Lf_{intertie}}$ is a vector of loss factors for each of the interties with separate entries for exports and imports if required.

$\mathbf{P_{interie}}^{T}$ are vectors of flows over each of the interties for the virtual change case load flow and the base case load flow. Separate entries are provided to correspond to the exports and imports given in the loss factor vector.

$\mathbf{P_{gen}}$ is a vector of all generators to which losses are assigned. For the proposed methodology the base case and change case generation is the same so the interties become the sole contributor to the loss assignment equation. The generator vector is retained in the algorithm for future flexibility.

$\mathbf{Lf_{gen}}$ is a vector of loss factors for each of the assigned generators.

With two interties (both import and export) the results from a total of four variation load flow cases would be required to solve for the two sets of loss factors. With more than four load flow cases, Equation (3) above cannot be solved for loss factors that will satisfy each virtual load flow condition hence an averaging procedure is proposed.

Generator 'raw' loss factors will be established for each season and are ultimately weighted during 'normalization' to establish a single loss factor for each generator. In a similar fashion, it is proposed that 'raw' intertie loss factors be determined for each season. To take into account the impact on all of the operating conditions, Equation (3) above is modified to:

$$\sum \Delta \mathrm{L} = \sum \begin{pmatrix} (\mathbf{P}_{\mathbf{interie}_{\text{change}}} - \mathbf{P}_{\mathbf{interie}_{\text{base}}})^{\mathrm{T}} \cdot \mathbf{Lf}_{\mathbf{intertie}} \\ + (\mathbf{P}_{\mathbf{gen}_{\text{change}}} - \mathbf{P}_{\mathbf{gen}_{\text{base}}})^{\mathrm{T}} \cdot \mathbf{Lf}_{\mathbf{gen}} \end{pmatrix} \qquad \text{Equation (4)}$$

The summation is carried out for all cases within the season where there are exports or imports over each intertie. In the case of BC and Sask. imports and exports, the summation would be carried out for:

- All virtual load flow cases with imports from BC
- All virtual load flow cases with exports to BC
- All virtual load flow cases with imports from Sask.
- All virtual load flow cases with exports to Sask.

If the situation were to arise where say there were no expected exports to Sask., an export loss factor for Sask. would not be required and that condition would be dropped from the list of summations. If more interties were added, the summation list would expand to include their impacts.

In the above set of equations for each season, there will be one equation for each of the unknown loss factors. This set of simultaneous equations can be solved for the intertie loss factors establishing a 'raw' loss factor for each season for each intertie for imports and for exports (as applicable).

The methodology effectively applies equal weighting to each of the virtual load flow conditions. Hence with the final loss factors selected, the losses associated with each virtual load flow may be under or over charged. However, the total (or average) losses associated with each of the import or export conditions above will be fully recovered and therefore, the average losses for all of the load flows are fully recovered as well.

As intertie loss factors are subject to the system shift factor and ultimately loss factor compression, they are treated the same as generators during these two stages of loss factor development. The seasonal loss factors are weighted according to projected seasonal volumes to establish an annual uncompressed loss factor. If required, the loss factors are compressed along with the loss factors of the generators to achieve the maximum charge of twice system average loss factor or maximum credit equal to the magnitude of the average system loss factor.