AESO Resolution of Issues on the 2006 Loss Factor Methodology
2005-04-01

Issue	Resolution
Methodology for Loss Factors in 2006 – 18 methodologies have been examined and ranked by Teshmont, with an additional two methodology evaluations included at stakeholder request. The additional methods were ranked by the same criteria - please see Note 1 and 2 for details.	The 50% Area Load Adjustment Corrected R Matrix, after the original ranking of 18 methods and subsequent ranking of two additional methods still best reflects the Transmission Regulation and principles as developed in the stakeholder consultation 2004. The AESO will proceed with following Teshmont's recommendation and implement this solution.
Transmission Must Run – Some stakeholders have indicated the TMR units should not be included in the base cases when determining loss factors.	In the 2006 AESO GTA, TMR was not included in the Calgary Area, and unless requirements change it won't be used in 2006. The Transmission Regulation (19-2-c) states the system is required to be operated in a normal state. Therefore, TMR will be included in the bases cases (for the Rainbow Area), and at the minimum amount specified by the applicable OPP to ensure normal operation (i.e. without TMR, the system couldn't operate, load would be un-served).
Import and Export loss factors, Accounting for loss factors – Stakeholders have requested clarity of the use of a single loss factor at the border versus a range or curve that could be used to allocate losses.	One annual loss factor for import and export for each inter-tie.
Import and Export loss factors, Export Loss Factors – questions arose as to whether an exporter was being charged for losses through the export loss factor and also paying for some of the losses again in the pool price.	The proposed method does not result in the exporter paying for redundancy in loss charges based on system average conditions. See attached analysis. Please see Note 3.
Software Development by Teshmont to enact methodology – software needs to be coded and tested to allow the AESO to ensure accurate implementation of the new methodology	In order to meet timelines imposed by the regulation, AESO will issue instructions to Teshmont to proceed with developing the software.
Additional Budget – out of scope items have been identified by stakeholders as necessary in the project.	Additional funds above the project cost are being allocated through the loss factor deferral account.

Note 1:
Methodology for Loss Factors for 2006
Alternative Method – R Matrix Incremental Loss Factor Methodology

Attached are revised evaluation tables which include an evaluation of the analytical interpretation of ATCO's proposed methodology (Incremental Loss Factor). The evaluation is based on the twelve 2003 base case load flows, as used in the original evaluation (December 2004).

The methodology uses the corrected R-bus for each load flow as a starting point. The loss factor at a generator bus is determined by reducing the output of the generator to zero and redistributing the reduction to all loads in the Alberta system. The loss factor is determined by dividing the change in system losses by the amount of generation reduction. At generator buses where the output is zero, the amount of power reduction is set equal to 0.00001MW (i.e. the marginal loss factor).

Similar to the rest of the analytical methods, an assumption is made that the R-matrix is unchanged as a result of the change in generation and load.

The Incremental Loss Factor Methodology (ILF) ranks in the middle (8th to 10th) of all 18 of the alternatives in terms of magnitude of shift factor required, the number of generators that exceed the loss factor limits, the range of the loss factors, and the seasonal volatility in the loss factors, and ranks 9th overall.

Results of the Incremental Loss Factor Methodology

- The methodology ranks tenth for required Load Flow shift factors,
- The methodology ranks tenth for the number of generating units with raw loss factors outside of the loss factor envelope (78 out of 124 generating units), and
- The methodology ranks eleventh for the range of the loss factors (20.74% credit to 16.36% charge).

Conclusions

The conclusions using the full system model are for the most part similar to the conclusions drawn with the 4 bus test system (ATCO's test system). The 4 bus test system however showed a smaller relative shift factor than the full test system. It is believed that with the radial nature of the test circuit, the majority of the losses associated with each branch are relegated to the nearest generator. Teshmont ran a small test with an artificial branch between Fort MacMurray and Rainbow Lake and while the overall losses were reduced, unallocated losses increased by about 20 MW, indicating that meshing of the network will result in over allocation of losses using the incremental loss factor method. In the full system test, the overall loss allocation is close to 50% of the total system losses with the ILF method. This means that approximately half of the losses assigned to generating units are socialized (i.e. loss assignment is achieved by a proportional assignment process). This is inconsistent with Section 19(2)(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”.

With the relatively large range in loss factors (37%) and the large number of generators exceeding the criteria, (78) the compression algorithm proposed in the Part 3 report would not be satisfactory. The majority of the units would be either at maximum charge or maximum credit and the locational based signals required by the Government’s Policy Paper would be lost. This method could result in most generating units having loss factors near the extremities of the loss factor envelope and the base loaded units in the Edmonton area being assigned loss factors near the system average losses. The result is that the compression of the loss factors is such that the methodology doesn’t meet the Regulation’s requirements in Section 19(2)(d).

To achieve a distribution of loss factors closer to the intent of compression, the linear compression algorithm would be required. Special rules would have to be developed to deal with low power large loss factor generators. This is required to avoid having small unit outliers from swinging large units around system average losses. Applying linear compression to the loss factors for the 4 bus ATCO test system would result in a reduction in charges and credits at Fort MacMurray and Rainbow Lake respectively but would result in a loss factor charge of about 3% at the load bus.

The proposed ILF methodology will not provide meaningful results for areas where the shutdown of generation will create an unreasonable operating condition (i.e. loss of firm load). This is almost the case in the 4-bus test system for shutdown of the Rainbow Lake generating unit. Loss of that unit in the load flow results in losses in the Rainbow Lake circuit equal to the power delivered. If huge voltage support is not provided at Rainbow Lake, the power flow will not solve.

Based on the above factors, inclusion of the ILF methodology in the attached methodology evaluation does not alter Teshmont's recommendation to use the Corrected R Matrix 50% Area Load Adjustment methodology.

Table 1 Load Flow Shift Factors Required For Each Methodology (Part "a")

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology	ILF Methodology
WnPk	4.77%	-2.84%	-0.70%	0.96%	2.03%	1.19%	-11.95%	0.65%	-2.50%
WnMd	5.16%	-3.62%	-1.84%	0.77%	1.66%	1.28%	-7.63%	0.68%	-2.89%
WnLw	6.42%	-6.77%	-5.72%	-0.18%	0.35%	1.82%	2.50%	0.40%	-3.68%
SpPk	5.01%	-3.19%	-1.67%	0.91%	1.67%	1.26%	-9.02%	0.70%	-2.68%
SpMd	5.05%	-3.66%	-2.16%	0.69%	1.45%	1.27%	-5.68%	0.75%	-2.83%
SpLw	6.41%	-6.87%	-7.16%	-0.23%	-0.37%	1.98%	9.49%	0.38%	-3.57%
SmPk	4.32%	-2.95%	-0.43%	0.68%	1.94%	0.91%	-11.19%	0.49%	-2.13%
SmMd	4.55%	-3.66%	-1.85%	0.44%	1.35%	0.90%	-5.28%	0.47%	-2.45%
SmLw	6.03%	-7.14%	-6.41%	-0.55%	-0.19%	1.72%	5.81%	0.06%	-3.08%
FlPk	4.22%	-2.61%	-0.51%	0.81%	1.86%	0.86%	-12.00%	0.46%	-1.93%
FlMd	4.65%	-3.81%	-2.09%	0.42%	1.28%	0.89%	-5.52%	0.39%	-2.51%
FlLw	5.86%	-6.77%	-5.73%	-0.45%	0.07%	1.47%	3.33%	0.11%	-3.18%
Winter Average		-4.41%	-2.75%	0.52%	1.35%	1.43%	-5.69%	0.58%	-3.02%
Spring Average		-4.57%	-3.66%	0.46%	0.92%	1.50%	-1.74%	0.61%	-3.03%
Summer Average		-4.58%	-2.90%	0.19%	1.03%	1.18%	-3.55%	0.34%	-2.55%
Fall Average		-4.40%	-2.78%	0.26%	1.07%	1.07%	-4.73%	0.32%	-2.54%
Annual Average		-4.49%	-3.02%	0.36%	1.09%	1.29%	-3.93%	0.46%	-2.79%

Legend
Largest Shift Factor per Methodology
Smallest Shift Factor per Methodology

Table 2 Load Flow Shift Factors Required For Each Methodology (Part "b")

Loading Condition	Average Loss Factor	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%

Loading Condition	Average Loss Factor	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology
WnPk	4.77%	-2.84%	-0.70%	0.96%	2.03%	1.19%	-11.95%	0.65%	-2.50%
WnMd	5.16%	-3.62%	-1.84%	0.77%	1.66%	1.28%	-7.63%	0.68%	-2.89%
WnLw	6.42%	-6.77%	-5.72%	-0.18%	0.35%	1.82%	2.50%	0.40%	-3.68%
SpPk	5.01%	-3.19%	-1.67%	0.91%	1.67%	1.26%	-9.02%	0.70%	-2.68%
SpMd	5.05%	-3.66%	-2.16%	0.69%	1.45%	1.27%	-5.68%	0.75%	-2.83%
SpLw	6.41%	-6.87%	-7.16%	-0.23%	-0.37%	1.98%	9.49%	0.38%	-3.57%
SmPk	4.32%	-2.95%	-0.43%	0.68%	1.94%	0.91%	-11.19%	0.49%	-2.13%
SmMd	4.55%	-3.66%	-1.85%	0.44%	1.35%	0.90%	-5.28%	0.47%	-2.45%
SmLw	6.03%	-7.14%	-6.41%	-0.55%	-0.19%	1.72%	5.81%	0.06%	-3.08%
FlPk	4.22%	-2.61%	-0.51%	0.81%	1.86%	0.86%	-12.00%	0.46%	-1.93%
FlMd	4.65%	-3.81%	-2.09%	0.42%	1.28%	0.89%	-5.52%	0.39%	-2.51%
FlLw	5.86%	-6.77%	-5.73%	-0.45%	0.07%	1.47%	3.33%	0.11%	-3.18%
Winter Average		-4.41%	-2.75%	0.52%	1.35%	1.43%	-5.69%	0.58%	-3.02%
Spring Average		-4.57%	-3.66%	0.46%	0.92%	1.50%	-1.74%	0.61%	-3.03%
Summer Average		-4.58%	-2.90%	0.19%	1.03%	1.18%	-3.55%	0.34%	-2.55%
Fall Average		-4.40%	-2.78%	0.26%	1.07%	1.07%	-4.73%	0.32%	-2.54%
Annual Average		-4.49%	-3.02%	0.36%	1.09%	1.29%	-3.93%	0.46%	-2.79%

Legend
Largest Shift Factor Per Load Flow or Season
Smallest Shift Factor Per Load Flow or Season

Table 3 Range of Loss Factors per Methodology

	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology
Maximum Loss Factor	28.72%	18.88%	26.57%	17.82%	15.89%	11.51%	16.15%	7.95%
Minimum Loss Factor	-33.14%	-21.29%	-29.76%	-19.21%	-12.28%	-7.00%	-18.13%	-24.16%
Range of Loss Factors	61.86%	40.17%	56.33%	37.03%	28.17%	18.52%	34.28%	32.12%
No. Greater Than Maximum Permitted	20	20	20	20	19	3	17	0
No. Less Than Minimum Permitted	66	60	63	58	38	9	41	19
No of Generators Exceeding Criteria	86	80	83	78	57	12	58	19
Seasonal Volatility	11.45%	11.37%	10.22%	10.31%	4.87%	4.92%	8.07%	6.78%

	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology
Maximum Loss Factor	26.91%	18.12%	16.06%	11.66%	10.33%	17.29%	11.23%	16.36%
Minimum Loss Factor	-30.34%	-19.77%	-12.57%	-7.28%	-5.30%	-18.06%	-6.35%	-20.74%
Range of Loss Factors	57.25%	37.89%	28.62%	18.95%	15.62%	35.35%	17.57%	37.11%
No. Greater Than Maximum Permitted	20	20	20	3	0	20	3	20
No. Less Than Minimum Permitted	64	60	40	9	1	57	2	58
No of Generators Exceeding Criteria	84	80	60	12	1	77	5	78
Seasonal Volatility	10.43%	10.69%	4.98%	5.10%	4.01%	9.02%	4.46%	7.28%

Legend
- Largest Magnitude per Methodology
- Smallest Magnitude per Methodology

Table 4 Ranking of Methodologies Based on Magnitude of Shift Factor

Loading Condition	Average Loss Factor	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology
WnPk	4.77%	10	7	14	13	1	2	9	15
WnMd	5.16%	12	9	14	13	1	2	7	15
WnLw	6.42%	11	10	16	13	5	1	6	14
SpPk	5.01%	10	6	14	13	1	2	9	15
SpMd	5.05%	11	9	14	13	1	2	7	16
SpLw	6.41%	9	8	15	11	5	1	6	12
SmPk	4.32%	8	7	14	13	2	1	9	15
SmMd	4.55%	11	10	14	13	2	1	6	16
SmLw	6.03%	8	10	16	13	6	1	5	12
FlPk	4.22%	9	6	14	13	2	1	5	15
FlMd	4.65%	11	10	14	13	2	1	7	16
FlLw	5.86%	9	11	16	14	6	1	5	12
Winter Average		11	9	15	13	2	1	7	16
Spring Average		10	9	15	14	2	1	6	16
Summer Average		10	8	15	14	4	1	7	16
Fall Average		10	8	16	14	4	1	5	15
Annual Average		10	8	15	14	3	1	6	16
Weighted Average		10.06	8.36	14.94	13.56	2.94	1.11	6.33	15.39
Overall Ranking		11	8	15	14	3	1	6	16

Loading Condition	Average Loss Factor	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology
WnPk	4.77%	12	4	5	8	6	16	3	11
WnMd	5.16%	11	8	4	6	5	16	3	10
WnLw	6.42%	15	12	2	3	7	8	4	9
SpPk	5.01%	12	7	4	8	5	16	3	11
SpMd	5.05%	12	8	3	6	5	15	4	10
SpLw	6.41%	13	14	2	3	7	16	4	10
SmPk	4.32%	12	3	5	10	6	16	4	11
SmMd	4.55%	12	8	3	7	5	15	4	9
SmLw	6.03%	15	14	4	3	7	11	2	9
FlPk	4.22%	12	4	7	10	8	16	3	11
FlMd	4.65%	12	8	4	6	5	15	3	9
FlLw	5.86%	15	13	4	2	7	10	3	8
Winter Average		12	8	3	5	6	14	4	10
Spring Average		13	12	3	5	7	8	4	11
Summer Average		13	11	2	5	6	12	3	9
Fall Average		12	11	2	6	7	13	3	9
Annual Average		13	11	2	5	7	12	4	9
Weighted Average		12.75	10.03	2.81	5.42	6.53	12.64	3.61	9.53
Overall Ranking		13	10	2	5	7	12	4	9

Legend
Largest Ranking Per Load Flow or Season
Smallest Ranking Per Load Flow or Season

Table 5 Overall Ranking Of Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology
Shift Factor	1	11	8	15	14	3	1	6	16
Number of Generators That Exceed the Limits	1	16	12	14	10	6	3	7	5
Range of Loss Factors	1	16	13	14	10	5	3	8	7
Seasonal Volatility	1	16	15	11	12	3	4	9	7
Swing Independent	1	15	15	1	1	1	1	1	1
Weighted Sum		14.80	12.60	11.00	9.40	3.60	2.40	6.20	7.20
Final Ranking		16	15	12	10	2	1	7	8

Criteria	Weighting	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology
Shift Factor	1	13	10	2	5	7	12	4	9
Number of Generators That Exceed the Limits	1	15	12	8	3	1	9	2	10
Range of Loss Factors	1	15	12	6	4	1	9	2	11
Seasonal Volatility	1	13	14	5	6	1	10	2	8
Swing Independent	1	1	1	1	1	15	15	15	1
Weighted Sum		11.40	9.80	4.40	3.80	5.00	11.00	5.00	7.80
Final Ranking		14	11	4	3	5	12	5	9

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 7 Overall Ranking Of Corrected Matrix Methodologies

Criteria	Weighting	Corrected R-matrix Swing Bus Methodology	Corrected R-matrix Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Corrected R-matrix Direct Methodology	Corrected R-matrix Gradient Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology
Shift Factor	1	5	9	1	10	7	3	4	8	2	6
Number of Generators That Exceed the Limits	1	9	7	3	5	9	3	1	6	2	7
Range of Loss Factors	1	10	7	3	5	9	4	1	6	2	8
Seasonal Volatility	1	10	8	3	5	9	4	1	7	2	6
Swing Independent	1	9	1	1	1	1	1	9	9	9	1
Weighted Sum		8.60	6.40	2.20	5.20	7.00	3.00	3.20	7.20	3.40	5.60
Final Ranking		10	7	1	5	8	2	3	9	4	6

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 8 Overall Ranking Of Uncorrected Matrix Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Uncorrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology
Shift Factor	1	4	6	2	3	5	1
Number of Generators That Exceed the Limits	1	6	4	1	2	5	3
Range of Loss Factors	1	6	4	1	3	5	2
Seasonal Volatility	1	6	4	1	3	5	2
Swing Independent	1	6	1	1	1	1	1
Weighted Sum		5.60	3.80	1.20	2.40	4.20	1.80
Final Ranking		6	4	1	3	5	2

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Note 2:

The Flow Tracking method as proposed by TransCanada Energy was evaluated by Teshmont and the results are as follows:

- Based on a full system test, the flow tracking methodology fails when situations arise where a generator is small but the var flow in adjacent circuits are large. Such would be the case for units connected primarily for voltage control or for small units connected close to buses with large capacitors. A solution could be to ignore loss factors for small units, but this would require some formula to decide under which situation a unit should be ignored. This will be more complicated than a simple MW criteria as Mvar to MW ratio comes into play.
- Load flow accuracy appears to be important for the methodology. Smaller magnitude branch losses are less accurate resulting in less accurate loss factors related to those losses.
- With the methodology there are no credits and all load buses or buses with generation less than load will be assigned a loss factor of zero. This will make it necessary to adopt another methodology for export and DOS loss factors.
- The compressed loss factor range will be less than twice system average or less than 2/3 of the range targeted by the DOE. If an evaluation factor (penalty) for a range less than this was to be included to represent strength of generation signals, the methodology would rank low (i.e. not attractive) in the evaluation matrix with a large number of generators outside of the limits and a large loss factor range.

AESO will have a ranking matrix available in the next couple of days if required.

Note 3:

The AESO has investigated the issue of double-counting for losses for export.

In the proposed methodology by AESO, 12 seasonal bases cases are used for determining the generator loss factors. These 12 base cases are prepared with zero export and import amounts.

Additional cases are prepared including export and import amounts for the purpose of tie loss factor calculation. The tie transactions in the additional cases are as follows:

1. SPC = 0, BCH = 200 (12 cases)
2. SPC = 0, BCH = 600 (12 cases)
3. SPC = 150, BCH = 0 (12 cases)
4. SPC = 150, BCH = 200 (12 cases)
5. SPC = 150, BCH = 600 (12 cases)

Export is considered for low and medium cases whereas import is considered for high cases only.

Average export and import loss factors are calculated from corresponding curves obtained using the cases mentioned above. Winter low and medium cases (200 MW export to BC) are picked to demonstrate the impact of the tie and generator loss factors on loss recovery.

Winter Low Case

The marginal generator in the case without tie transaction is Sundance 1 with generation amount of 188.9 MW. However, for exporting 200 MW to BC additional generation is required and Battle River 5 becomes the marginal unit with 193.8 MW of generation in the case with tie transaction. Table 1 shows summary of result obtained in the analysis.

Table 1: Summary of loss recovery in the winter low case for 200 MW of export.

Case	Winter Low											
		Base Case				Tie BC 200 Case				Difference		
GSO #	Gen	Dispatch	LF	Loss Contribution	Total loss	Dispatch	LF	Loss Contribution	Total loss	Loss Contribution	Total Loss	Surplus/ Deficit
141	SD1	188.9	6.90%	13.03		268.1	6.90%	18.50				
142	WB4	135.0	7.11%	9.60		246.0	7.11%	17.49				
143	BR5	140.0	2.97%	4.16		193.8	2.97%	5.76				
	Tie	0.0	7.00%	0.00		200.0	7.72%	15.44				
	Sum			26.79	266.80			57.19	304.80	30.39	38.00	-7.61

Table 1 shows the dispatch of Sundance 1, Wabamun 4 and Battle River 5 before and after the 200 MW of export to BC scenarios. The loss factors of generators and tie are used to calculate their contribution to the change in the total system loss before and after. Tie Line loss factor is obtained from version 5 (sent by Teshmont).

Table 1 shows that change in the total system losses is 38 MW and the total recovery of losses from both generators and Tie is 30.39 MW. Clearly, there is a deficit of 7.61 MW and any surplus or deficit is the direct consequence of using an average loss factor number regardless of cases. The generators are paying more for increased generation but their contribution is still not sufficient for the total recovery of additional loss caused by the 200 MW of export.

Winter Medium Case

The marginal generator in this case (with zero transaction) is Calpine. Table 2 shows the result for winter medium condition with 200 MW of export.

Table 2: Summary of loss recovery in the winter medium case for 200 MW of export.

Case	Winter Medium											
		Base Case				Tie BC 200 Case				Difference		
GSO #	Gen	Dispatch	LF	Loss Contribution	Total loss	Dispatch	LF	Loss Contribution	Total loss	Loss Contribution	Total Loss	Surplus/ Deficit
177	CALPINE G1	85.9	-0.73%	-0.63		125.7	-0.73%	-0.92				
178	CALPINE G2	24.0	-0.73%	-0.18		94.1	-0.73%	-0.69				
179	BALZAC G1	0.0	-0.82%	0.00		30.7	-0.82%	-0.25				
180	BALZAC G1	0.0	-0.82%	0.00		30.7	-0.82%	-0.25				
181	BALZAC G1	0.0	-0.82%	0.00		18.8	-0.82%	-0.15				
182	CAVALIER G1	0.0	-1.42%	0.00		20.9	-1.42%	-0.30				
	Tie	0.0	7.00%	0.00		200.0	7.72%	15.44				
	Sum			-0.80	302.10			12.88	304.90	13.68	2.80	10.88

The marginal unit after 200 MW of export is Cavalier G1 with 20.9 MW of generation. The loss recovery from both generators and Tie is 13.68 MW whereas the change in total system loss is 2.8 MW. Although there is a surplus of 10.88 MW none of the generators (with additional generation for 200 MW of export) are paying anything extra - rather they are getting credit. The reason for surplus is due to an average loss factor number.

Conclusion

The surplus or deficit shown in the Tables would have been zero if the tie loss factor calculated from the corresponding cases were used. In the case of deficiency, clearly no generator is overpaying for additional generation and in the case of surplus, no generator is paying extra - rather they are receiving loss credits for additional generation. In either case, generators and exports are not charged for the same loss twice.