BENEFIT/COST ANALYSIS BASED ON RELIABILITY AND TRANSMISSION LOSS CONSIDERATIONS FOR CENTRAL VANCOUVER ISLAND TRANSMISSION PROJECT

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Regional System Planning,
System Planning and Performance Assessment
British Columbia Transmission Corporation

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Executive Summary

Central Vancouver Island 138 kV transmission circuits (1L115 and 1L116) are heavily loaded and are approaching their capacity limits during the high load in winter under system normal condition. Both 1L115 and 1L116 circuits are equipped with a Remedial Action Scheme (RAS) that is designed to open 1L115 and 1L116 at the JPT end if an overload on these circuits is detected, causing load to be served from VIT. This will result in overloads on the four 230/138 kV transformers at VIT if the RAS operates. The Central Vancouver Island Transmission project is intended to resolve thermal constraints on the 138 kV system in Central Vancouver Island (circuits 1L115 and 1L116) as well as at the four 230/138 kV transformers at Vancouver Island Terminal Substation (VIT).

Five Central Vancouver Island Transmission (CVIT) reinforcement alternatives were considered in this report. These alternatives are: 230kV Injection (Option a), Phase Shifters (Option b), 500kV Conversion (Option c), Reconductoring (Option d) and SAT Transformation (Option e). Probabilistic reliability assessment and transmission loss evaluation for the CVIT reinforcement project are presented in this report to provide a quantitative assessment of the expected energy not supplied (EENS) and the loss reduction after the implementation of the CVIT project. The benefits in terms of reliability improvement and loss reduction are mainly focused in this study. The benefit/cost analysis for the five CVIT reinforcement alternatives is presented. The following findings are concluded in the report.

- *The EENS reductions (reliability improvement) due to the five CVIT reinforcement alternatives are very significant when comparing with that of Do Nothing Option (EENS reductions are greater than 1,800 MWh/yr).*
- *In reliability perspective, the 230kV Injection option offers the greatest EENS reduction following by the 500kV Conversion, SAT Transformation, Reconductoring and Phase Shifters options respectively.*
- *In transmission loss reduction viewpoint, all the five CVIT reinforcement alternatives will help in reducing system loss. The 500kV Conversion option provides the greatest loss reduction following by the Reconductoring, 230kV Injection and Phase Shifters and SAT Transformation options respectively.*
- *In all the five CVIT reinforcement options, the reliability improvement benefit (EENS reduction) is much more significant than the loss reduction benefit as the system is highly constrained and prone to have major reliability concerns.*
- *The benefit/cost analysis indicates that all the five CVIT reinforcement alternatives have the economic justification as the Net Present Values are positive (Benefit/Cost Ratios are greater than 1). The most cost-effective solution is the 230kV Injection option that offers*

the Benefit/Cost Ratio of 8.4 and 14.5 (NPV equals to M$281.6 and M$400.6) when using the discount rates of 6% and 2.5% respectively. The second best cost-effective alternative is the SAT Transformation option (NPV equals to M$234.8 for 6% discount rate and M$339.0 for 2.5% discount rate) following by the 500kV Conversion, Phase Shifters and Reconductoring options respectively.

Table of Content

Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project

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1. Introduction

Load growth in Central Vancouver Island has resulted in the transmission system experiencing thermal constraints in the following two areas; 1) The 138 kV circuits designated as 1L115 and 1L116 from Dunsmuir Substation (DMR) near Qualicum to Jingle Pot Substation (JPT) near Nanaimo, 2) The four 230/138 kV transformers at Vancouver Island Terminal (VIT) north of Duncan.

Central Vancouver Island 138 kV transmission circuits (1L115 and 1L116) are heavily loaded and are approaching their capacity limits during the high load in winter under system normal condition. Both 1L115 and 1L116 circuits are equipped with a Remedial Action Scheme (RAS) that is designed to open 1L115 and 1L116 at the JPT end if an overload on these circuits is detected, causing load to be served from VIT. This will result in overloads on the four 230/138 kV transformers at VIT if the RAS operates. The Central Vancouver Island Transmission project is intended to resolve thermal constraints on the 138 kV system in Central Vancouver Island (circuits 1L115 and 1L116) as well as at the four 230/138 kV transformers at Vancouver Island Terminal Substation (VIT).

Probabilistic reliability assessment and transmission loss evaluation for the Central Vancouver Island Transmission (CVIT) project is presented in this report to provide a quantitative assessment of the expected energy not supplied (EENS) and the transmission loss reduction due to the implementation of the CVIT reinforcement project. The benefits in terms of reliability improvement (EENS reduction) and transmission loss reduction are mainly focused in this study. The benefit/cost analysis for the CVIT reinforcement alternatives is presented in this report.

2. Study Conditions and Assumptions

The study conditions and assumptions used in the study are as follows:

- The Central and South Vancouver Island system is used in the study as shown in Figure A.1 (2008 – 2009) and Figure A.2 (2010 – 2020) in Appendix A. The study does not focus on the Northern Vancouver Island system as it does not have impact the flows through 1L115 and 1L116. The Northern Vancouver Island system is therefore modeled as an equivalent load and generator connected to DMR substation.
- The Central Vancouver Island Transmission (CVIT) project is assumed to be in-service in October 2010.
- The 1L10 and 1L11 thermal upgrade project is assumed to be in-service in 2007. The Retermination of Sidney to Keating project is assumed to be in-service in 2010.
- The Qualicum Substation Reconfiguration project (F09 project seeking for approval) is assumed to be in-service in October 2008. This project helps to equalize and therefore maximize the flows on 1L115 and 1L116 resulting in reduction of the likelihood of load curtailment due to an overload tripping by RAS under normal system condition.
- Load duration curve for Vancouver Island is shown in Appendix B, Figure B.1. The load profile was obtained from PI system based on 2006 data. The future VI load is assumed to have a similar pattern to that shown in Figure B.1.
- BC Hydro load forecast (2006/07 – 2016/17) was used in the study. Load growth beyond 2016/17 is assumed to have 1% load growth rate.
- Substation load coincident factors for Vancouver Island system were considered in order to present the realistic situation in which all substation loads do not reach their peak loads at the same time. These substation load coincident factors were calculated based on the hourly chronological substation load data in the past 3 years during the VI system peak period, which obtained from RDMS. The substation coincident factors for Vancouver Island system for winter and summer seasons are shown in Appendix C.
- Reliability data (failure rate and repair time) for transformers and transmission lines in Central and South Vancouver Island system are obtained from Reliability Database Management System (RDMS) during the past 10 years.
- The VITR (230kV AC cable) is assumed to be in service in 2008. HVDC Poles 1 and 2 are assumed to be decommissioned after VITR is in-service.
- The unavailability of Jordan River Generation (JOR-G1) is dependent on the water condition as it is the run-off-river generation. The unavailability due to the water condition dominates the unavailability due to a mechanical failure of the generator. In regional system planning perspective, JOR-G1 is a very important local energy source to supply South VI system. This study therefore utilizes the unavailability of the water condition for the JOR-G1 reliability modeling. Jordan River generation pattern is shown in Appendix D, Figure D.1. The probability of having zero megawatt output is 0.46 based on the historical operating data.

3. Reliability Modeling and Software

The study system as shown in Figures A.1 and A.2 composes of both generation and transmission facilities. Since the study is focused on Vancouver Island system, the supplies from the each terminal of 5L29, 5L31 and VITR on the Mainland are modeled as an equivalent generator connected to the end of each line. All the equivalent generators are assumed to be 100% reliable, and their maximum generation outputs are limited by the capacity of the lines where they are connected to, i.e. if 5L29 is out of service, the equivalent generator connected to 5L29 will have zero output, and the maximum power flows on the 5L31 will be limited at 1221 MW. Jordan River generation (JOR-G1) is a very important source for the local area, so it will model as a non-perfect reliability generator. The unavailability of JOR-G1 is 0.46 in this study.

All the transmission components (lines, cables and transformers) considered in this study are not 100% reliable. Their reliability data are obtained from the RDMS during the past 10 years.

The in-house software designated as MECORE Program [1] is used in this study to assess the composite generation and transmission system reliability. The MECORE Program utilizes a Monte Carlo Simulation approach associated with DC-based power flow and optimization techniques. The state sampling approach is used in the simulation process. The VI load duration curve is divided into 20 non-uniform steps. The number of samplings used in this study is 50,000 for each load step to achieve a coefficient of variation (error tolerance) less than 2.5%.

4. Transmission Loss Analysis Software

One of benefits of CVIT project is the transmission loss reduction. Different CVIT reinforcement alternatives could result in different degrees of transmission loss reductions. Therefore, the energy loss saving for different reinforcement alternatives could be monetized against the base case (Do Nothing Option). The in-house software designated as PLOSS Program [2] was used in the study to assess the transmission loss (MW) at the peak load and the annual energy loss (MWh) for different CVIT options. Vancouver Island load duration curve shown in Figure B.1 was incorporated in the PLOSS software in order to obtain the annual energy losses.

5. Study Results

5.1 Reliability Study Results

The expected energy not supplied (EENS) index is mainly focused in the study in order to investigate the potential risk of load curtailments based on the existing system condition, and also to investigate the potential reduction of load curtailments after implementing the CVIT project.

Table 5.1 presents the likelihood of the risk in terms of the magnitude of unserved energy based on the existing Central and South Vancouver Island system. The results shown in Table 5.1 are based on Do Nothing Option and will be used to compare against those results based on the implementation of the CVIT project.

Table 5.1: Expected Energy Not Supplied (EENS) based on the existing system (Do Nothing Option)

Year	EENS for Do Nothing Option (MWh/year)
2010/11	4215
2011/12	4635
2012/13	4958
2013/14	5463
2014/15	5993
2015/16	6532
2016/17	7121
2017/18	7972
2018/19	8984
2019/20	10062
2020/21	11383

There are five major CVIT reinforcement options originally being considered. The five options that have the cost estimates (-5% to +30% accuracy), and the fifth option with a ballpark cost estimate are summarized as follows:

a) 230 kV to 138 kV Injection ($82.2 million)
b) Phase Shifting Transformers and VIT Transformer Upgrades ($114.7 million)
c) Conversion of 2L123 and 2L128 to 500 kV operation and Related Upgrades ($153.0 million)
d) Rebuild 1L115 and 1L116 ($169.5 million)
e) SAT 230/138 kV Transformation and Phase Shifting Transformers ($78.0 million*)

* The cost estimate for Option e) is not yet available at the time of this study, and therefore it is assumed to be $78.0 million in this study for comparison purposes.

Option a) is to build 230 kV double circuits by tapping to 2L123 and 2L128, and then inject to 138 kV system at Harwood West Substation (a proposed new substation designated as HWW). An impact of common cause failure of the transmission tower from the tapped location to HWW is also considered in the study.

Option b) is to install phase shifting transformers at 138 kV level at DMR to control/limit the flows through 1L115 and 1L116. Two VIT transformers (180 MVA) will be replaced by new two larger transformers (300MVA) in order to accommodate higher flows through VIT transformers after installing phase shifters. To reduce a complexity of phase shifters in reliability modeling, the phase shifters are assumed to be 100% reliable with considerably large impedance in this study.

Option c) is to convert 230 kV circuits, 2L123 and 2L128 (DMR – SAT) to 500 kV operation. Two 500/230 kV transformers will be installed at SAT for 500 kV operation. Two VIT transformers will be replaced with 300 MVA units.

Option d) is to rebuild 1L115 and 1L116 in order to increase the individual line capability up to 367 MVA for normal rating. Two VIT transformers will be replaced with 300 MVA units.

Option e) is to install phase shifting transformers at 138 kV level at DMR to control/limit the flows through 1L115 and 1L116. Two 230/138kV SAT transformers together with 138kV switchyard are installed. Three 138kV circuits from SAT to 1L10, 1L11 and 1L14 will be constructed with approximately 5.5 km in length.

Table 5.2 presents the expected energy not supplied (EENS) for Options a) – e) based on the study conditions noted earlier in Section 2. The results shown in Table 5.2 are graphically presented in Figure 5.1.

Table 5.2: Expected Energy Not Supplied (MWh/yr) for five CVIT options

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	1724	2371	2325	2386	2340
2011/12	1754	2417	2367	2430	2380
2012/13	1773	2440	2394	2461	2410
2013/14	1805	2487	2434	2506	2453
2014/15	1842	2540	2478	2555	2487
2015/16	1878	2538	2473	2546	2491
2016/17	1904	2579	2508	2583	2527
2017/18	1947	2637	2562	2634	2565
2018/19	1985	2698	2611	2681	2610
2019/20	2027	2762	2662	2732	2661
2020/21	2078	2830	2718	2784	2711

Table 5.2 and Figure 5.1 indicate that the 230kV Injection Option (Option a) provide the lowest EENS (highest reliability improvement) throughout the planning period considered. Options b) – e) provide similar reliability improvement at the beginning of the planning period.

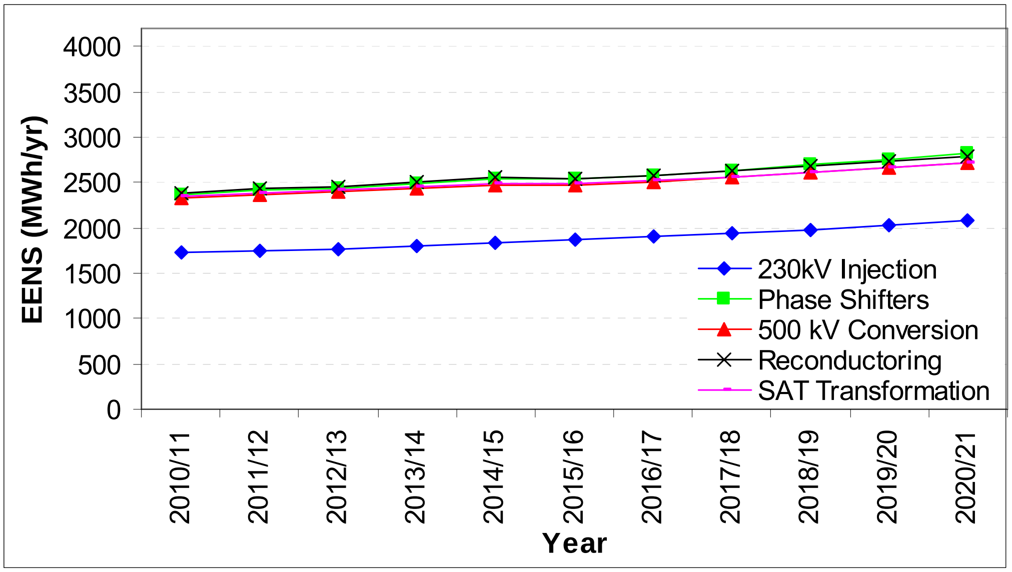

Figure 5.1: Expected Energy Not Supplied for five CVIT options

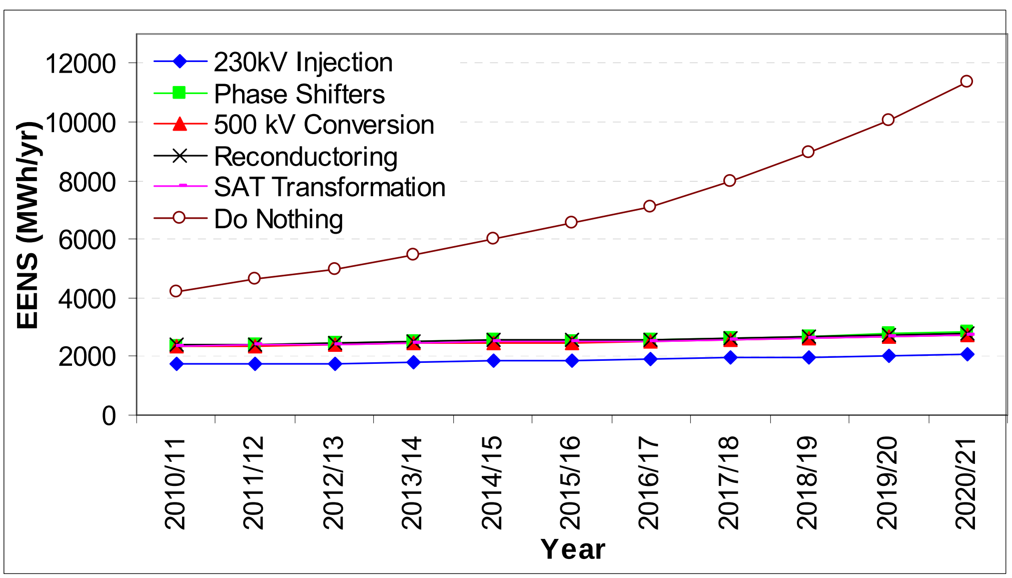

Figure 5.2: EENS comparisons of five CVIT options against with Do Nothing option

Figure 5.2 presents the EENS comparisons of the five CVIT alternatives shown in Table 5.2 against with those results shown in Table 5.1 for the base case (Do Nothing Option). Table 5.3 presents the EENS reductions based on the five CVIT options compared to the Do Nothing Option.

The results shown in Figure 5.2 and Table 5.3 indicate that all the five options offer significant EENS reduction compared to the Base Case (Do Nothing Option). These options are, therefore, considerably efficient in resolving the Central Vancouver Island constraints in a long-term. However, the option that offers the highest EENS reduction does not mean it will automatically be selected as a preferred option if its investment cost has not yet taken into account. The most cost-effective solution for CVIT will therefore require the benefit/cost analysis that will be presented later in this report.

Table 5.3: EENS reductions (MWh/yr) of the five CVIT options compared to the Do Nothing Option

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	2490	1844	1889	1828	1874
2011/12	2882	2218	2269	2206	2255
2012/13	3184	2518	2564	2497	2548
2013/14	3658	2975	3029	2957	3010
2014/15	4151	3453	3516	3438	3506
2015/16	4654	3995	4059	3986	4042
2016/17	5217	4542	4613	4538	4594
2017/18	6025	5334	5410	5338	5407
2018/19	6999	6286	6373	6302	6373
2019/20	8035	7300	7400	7329	7401
2020/21	9305	8553	8665	8599	8672

5.2 Transmission Loss Study Results

In addition to the reliability improvement benefit obtained from the CVIT reinforcement project, the transmission loss reduction should also be considered as the benefit as it will offer an annual energy loss saving throughout the planning period. The transmission loss consideration is addressed in this section. As previously noted, the in-house software designated as PLOSS Program [2] was used to assess transmission loss and energy loss. Table 5.4 and Figure 5.3 show the comparison of the five CVIT options together with the Do Nothing Option.

Table 5.4 and Figure 5.3 indicate that all the five different CVIT reinforcement alternatives result in lower transmission losses compared to the Base Case (Do Nothing Option). These options however offer different degrees of transmission loss reductions compared to the Do Nothing Option. The 500kV Conversion Option provides the highest transmission loss reduction while the SAT Transformation Option offers the lowest transmission loss reduction. The PLOSS software also offers the annual energy loss calculation. Given that the VI load duration curve as shown in Figure B.1, the energy losses for the five options together with the

Do Nothing Option are presented in Table 5.5. The annual energy loss reductions for all the five CVIT options compared to the Do Nothing Option are shown in Table 5.6.

Table 5.4: Comparison of transmission loss (MW) at peak load for different options

Year	Do Nothing Option	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Re-conductoring (Option d)	SAT Transformed (Option e)
2010/11	96.6	86.8	92.1	76.5	84.9	93.0
2011/12	99.4	89.3	94.7	76.5	87.1	95.4
2012/13	100.9	90.8	96.2	79.8	88.5	97.0
2013/14	103.8	93.5	98.9	82.2	90.9	98.9
2014/15	106.8	96.2	101.8	82.6	93.4	101.4
2015/16	108.4	97.8	103.3	86.2	94.8	103.5
2016/17	110.7	99.8	105.4	87.1	96.7	106.1
2017/18	112.9	101.7	107.6	88.4	98.6	107.6
2018/19	115.3	103.8	109.9	88.9	100.6	110.5
2019/20	117.8	106.2	112.3	89.8	102.8	113.0
2020/21	120.3	107.6	114.8	91.4	104.9	115.5

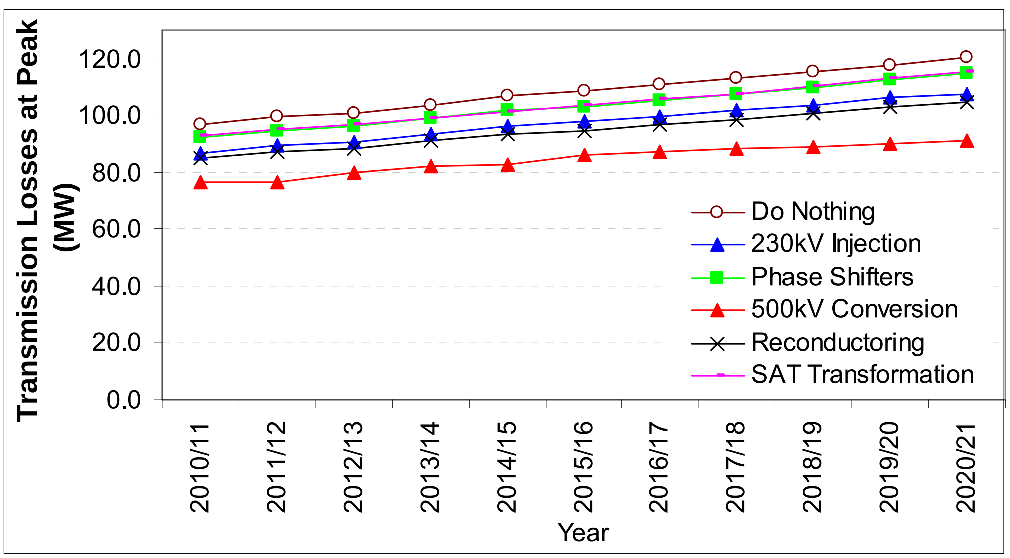

Figure 5.3: Comparison of transmission loss (MW) at peak load for different options

Table 5.5: Comparison of annual energy loss (MWh) for different options

Year	Do Nothing Option	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Re-conductoring (Option d)	SAT Transformed (Option e)
2010/11	263812	238446	252557	208595	232769	252637
2011/12	271523	245516	259997	209477	239084	259383
2012/13	275736	249485	263992	217760	242823	263896
2013/14	283649	257011	271622	224873	249678	269692
2014/15	292135	264741	279633	225873	256939	276670
2015/16	296392	269185	283692	235639	260587	282297
2016/17	302549	274606	289681	238285	265906	289417
2017/18	308699	280012	295705	241561	271298	293848
2018/19	315001	285570	301900	242944	276846	301761
2019/20	321510	291831	308293	246229	282560	308500
2020/21	328227	295896	314876	250980	288444	315132

Table 5.6: Annual energy loss reduction (MWh) for the five CVIT options

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Re-conductoring (Option d)	SAT Transformed (Option e)
2010/11	25367	11255	55217	31043	11175
2011/12	26007	11526	62046	32439	12140
2012/13	26252	11744	57977	32913	11840
2013/14	26638	12027	58776	33971	13957
2014/15	27394	12502	66262	35196	15464
2015/16	27207	12701	60753	35805	14095
2016/17	27944	12868	64265	36643	13132
2017/18	28687	12994	67138	37402	14851
2018/19	29431	13101	72057	38155	13240
2019/20	29679	13217	75281	38950	13010
2020/21	32331	13351	77247	39783	13095

6. Benefit/Cost Analysis

This section presents the economic analysis for the CVIT project. The reliability improvement and energy loss reduction benefits will be monetized and then be used against with the investment cost of the project to identify the most cost-effective solution.

6.1 Monetized Reliability Improvement Benefit

The customer outage cost can be used as a surrogate of socio-economic cost, and is used to represent reliability worth (benefit) for improving system reliability. The unit interruption cost (UIC) in $/kWh is used in this case to represent the monetary impact on customers due to unserved energy. Customer damage functions obtained from the customer interruption survey [3] are used in this approach. The UIC in $/kWh can be derived from the customer damage function as presented in Appendix E [4]. Customer load compositions in the area are also required in order to calculate composite UIC for the specified area. The customer load compositions and the composite UIC for selected Central and South VI substations are shown in Table 6.1. The last row in Table 6.1 provides the average unit interruption cost for the Central and South VI system, which is 9.04 $/kWh. This value will apply to the benefit calculation for the CVIT project.

Table 6.1: Customer load composition and composite unit interruption cost (UIC) for the Central and South VI substations (small substations are omitted in the table)

VI Substations	Residential	Commercial	Industrial	Composite UIC ($/kWh)
PVO	80%	13%	7%	6.98
LDY	71%	12%	17%	8.06
HWD	67%	20%	13%	10.31
KTG	84%	12%	4%	6.19
NFD	75%	21%	4%	9.37
PVL	81%	16%	3%	7.46
KSH	60%	21%	19%	11.53
SNY	76%	18%	6%	8.60
SHA	88%	10%	2%	5.20
GOW	84%	16%	0%	7.03
GTP	80%	19%	1%	8.23
HSY	60%	39%	2%	15.46
CLD	80%	17%	3%	7.82
SOO	91%	7%	2%	4.14
SAL	88%	10%	2%	5.20
LCW	83%	14%	3%	6.76
GLS	91%	8%	1%	4.35
LTZ	76%	23%	1%	9.65
QLC	88%	9%	3%	4.99
Central and South VI System Average				**9.04**

The benefit due to the EENS reduction (ΔEENS) as presented in Section 5 can be monetized and be presented as the reduction of the expected damage cost (ΔEDC). The expected damage cost reduction can be obtained from the multiplication of the specified unit interruption cost (9.04 $/kWh) and the EENS reduction shown in Table 5.3. The monetized reliability benefit (ΔEDC) of CVIT project is shown in Table 6.2.

Table 6.2: Monetized reliability benefit (EDC reduction in M$/yr) for the five CVIT options

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	22.51	16.67	17.08	16.53	16.94
2011/12	26.05	20.05	20.51	19.94	20.39
2012/13	28.79	22.77	23.18	22.57	23.03
2013/14	33.06	26.90	27.38	26.73	27.21
2014/15	37.53	31.21	31.78	31.08	31.69
2015/16	42.07	36.11	36.69	36.04	36.54
2016/17	47.16	41.06	41.70	41.02	41.53
2017/18	54.47	48.22	48.91	48.25	48.88
2018/19	63.27	56.82	57.61	56.97	57.61
2019/20	72.63	65.99	66.90	66.26	66.90
2020/21	84.12	77.32	78.33	77.74	78.39

6.2 Monetized Energy Loss Reduction Benefit

The energy loss reductions for the five CVIT reinforcement alternatives could be monetized. Assume the unit cost of energy losses is $88/MWh for Lower Mainland and Vancouver Island areas. The monetized energy loss savings for the five CVIT options are shown in Table 6.3.

Table 6.3: Monetized energy loss saving (M$/yr) for the five CVIT options

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	2.23	0.99	4.86	2.73	0.98
2011/12	2.29	1.01	5.46	2.85	1.07
2012/13	2.31	1.03	5.10	2.90	1.04
2013/14	2.34	1.06	5.17	2.99	1.23
2014/15	2.41	1.10	5.83	3.10	1.36
2015/16	2.39	1.12	5.35	3.15	1.24
2016/17	2.46	1.13	5.66	3.22	1.16
2017/18	2.52	1.14	5.91	3.29	1.31
2018/19	2.59	1.15	6.34	3.36	1.17
2019/20	2.61	1.16	6.62	3.43	1.14
2020/21	2.85	1.17	6.80	3.50	1.15

The results in Table 6.3 indicate that the benefit of loss reduction due to CVIT project is quite significant in some options such as the 500kV Conversion, Reconductoring, 230kV Injection options. However, these loss reduction benefits are much less than the benefits of reliability improvement (EDC reduction) as shown in Table 6.2. The benefits from reliability improvement and loss reduction are added up together to produce the overall benefit that will be used in the next section to identify the most cost-effective option for CVIT reinforcement.

6.3 Most Cost-Effective Solution Identification

The overall benefit of CVIT project considered in this study is the combined benefit of reliability improvement and energy loss reduction. The monetized reliability benefit shown in Table 6.2 and the monetized energy loss reduction benefit shown in Table 6.3 are therefore added together to obtain the overall benefit that is shown in Table 6.4.

Table 6.4: The overall benefit (M$/yr) for the five CVIT options

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	24.74	17.66	21.94	19.26	17.92
2011/12	28.34	21.06	25.97	22.79	21.46
2012/13	31.10	23.80	28.28	25.47	24.07
2013/14	35.40	27.96	32.55	29.72	28.44
2014/15	39.94	32.31	37.61	34.18	33.05
2015/16	44.46	37.23	42.04	39.19	37.78
2016/17	49.62	42.19	47.36	44.24	42.69
2017/18	56.99	49.36	54.82	51.54	50.19
2018/19	65.86	57.97	63.95	60.33	58.78
2019/20	75.24	67.15	73.52	69.69	68.04
2020/21	86.97	78.49	85.13	81.24	79.54

In the economic analysis,

Let us assume that:

- Discount rate is 6% and 2.5% (for sensitivity study purposes).
- Useful life time of the CVIT project is 40 years.
- Project costs for the five different CVIT alternatives are shown in Section 5 (-10%/+30% accuracy except for Option e) that has no planning cost estimate available at the time of this study).

The capital return factor (CRF) can be calculated using the following equation:

Using 6.0% discount rate:

Capital return factor ($CRF_{6\%}$) = $\dfrac{i(1+i)^n}{(1+i)^n - 1} = \dfrac{0.06(1+0.06)^{40}}{(1+0.06)^{40} - 1}$ = 0.06646

Using 2.5% discount rate:

Capital return factor ($CRF_{2.5\%}$) = $\dfrac{i(1+i)^n}{(1+i)^n - 1} = \dfrac{0.025(1+0.025)^{40}}{(1+0.025)^{40} - 1}$ = 0.03984

The annual capital payment (ACP) for the CVIT Reinforcement project can be calculated using the multiplication of the total capital cost and the capital return factor.

$ACP_{6.0\%}$ = P×0.06646
$ACP_{2.5\%}$ = P×0.03984

Where: P = Project cost (capital investment)

The ACP indicates the uniform series of annual payments (an annuity) from the beginning of the construction year through *n* years for the useful lifetime of the project. The ACP from 2010/11 to 2020/21 for all the five alternatives are shown in Tables 6.5 and 6.6 for discount rate of 6% and 2.5% respectively.

Table 6.5: Annual Capital Payments (ACP in M$/yr) for the five CVIT options from 2010/11 to 2020/21 using 6% discount rate

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	5.46	7.62	10.17	11.26	5.18
2011/12	5.46	7.62	10.17	11.26	5.18
2012/13	5.46	7.62	10.17	11.26	5.18
2013/14	5.46	7.62	10.17	11.26	5.18
2014/15	5.46	7.62	10.17	11.26	5.18
2015/16	5.46	7.62	10.17	11.26	5.18
2016/17	5.46	7.62	10.17	11.26	5.18
2017/18	5.46	7.62	10.17	11.26	5.18
2018/19	5.46	7.62	10.17	11.26	5.18
2019/20	5.46	7.62	10.17	11.26	5.18
2020/21	5.46	7.62	10.17	11.26	5.18

Table 6.6: Annual Capital Payments (ACP in M$/yr) for the five CVIT options from 2010/11 to 2020/21 using 2.5% discount rate

Year	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Reconductoring (Option d)	SAT Transformed (Option e)
2010/11	3.27	4.57	6.09	6.75	3.11
2011/12	3.27	4.57	6.09	6.75	3.11
2012/13	3.27	4.57	6.09	6.75	3.11
2013/14	3.27	4.57	6.09	6.75	3.11
2014/15	3.27	4.57	6.09	6.75	3.11
2015/16	3.27	4.57	6.09	6.75	3.11
2016/17	3.27	4.57	6.09	6.75	3.11
2017/18	3.27	4.57	6.09	6.75	3.11
2018/19	3.27	4.57	6.09	6.75	3.11
2019/20	3.27	4.57	6.09	6.75	3.11
2020/21	3.27	4.57	6.09	6.75	3.11

The present value (PV) based on 2007 for both benefits (ΔEDC + Loss Reduction) shown in Table 6.4 and the PV of costs (capital investment) shown in Tables 6.5 and 6.6 can be calculated using the following equations:

$$PV_{6.0\%} \text{ of Benefit} = \sum_{j=1}^{m} \frac{(Benefits)_j}{(1+0.06)^{j-1}}, \text{ and } PV_{6.0\%} \text{ of Cost} = \sum_{j=1}^{m} \frac{ACP_j}{(1+0.06)^{j-1}}$$

$$PV_{2.5\%} \text{ of Benefit} = \sum_{j=1}^{m} \frac{(Benefits)_j}{(1+0.025)^{j-1}}, \text{ and } PV_{2.5\%} \text{ of Cost} = \sum_{j=1}^{m} \frac{ACP_j}{(1+0.025)^{j-1}}$$

Where: m = planning period (i.e. 11 years in this case).

Benefit/Cost Ration (BCR) = (PV of Benefit)/(PV of Cost)
Net Present Value (NPV) = (PV of Benefit) – (PV of Cost)

Tables 6.7 and 6.8 show the PV of Benefit and Cost, Benefit/Cost Ration and Net Present Value for all the five CVIT reinforcement alternatives using 6% and 2.5% discount rates respectively.

Table 6.7: PV of benefit and cost (in M$), BCR and NPV for a given period using 6% discount rate

Index	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Re-conductoring (Option d)	SAT Transformed (Option e)
PV of Benefit	319.93	267.10	303.24	281.00	271.13
PV of Cost	38.33	53.49	71.39	79.04	36.36
Benefit/Cost Ratio	**8.35**	**4.99**	**4.25**	**3.56**	**7.46**
Net Present Value	**281.60**	**213.61**	**231.85**	**201.96**	**234.77**

Table 6.8: PV of benefit and cost (in M$), BCR and NPV for a given period using 2.5% discount rate

Index	230kV Injection (Option a)	Phase Shifters (Option b)	500kV Conversion (Option c)	Re-conductoring (Option d)	SAT Transformed (Option e)
PV of Benefit	430.23	361.76	409.01	380.01	367.18
PV of Cost	29.61	41.38	55.15	61.13	28.16
Benefit/Cost Ratio	**14.53**	**8.74**	**7.42**	**6.22**	**13.04**
Net Present Value	**400.62**	**320.37**	**353.86**	**318.89**	**339.02**

The results shown in Tables 6.7 and 6.8 indicate that all the five CVIT reinforcement alternatives have the economic justification as the NPV are positive (BCR is greater than 1). Using 2.5% discount rate offers more encouraging outcomes for project implementation as the BCR and NPV values are greater than those when using the 6% discount rate. There is slightly difference in this case for cost-effective option rankings when using both 6% and 2.5% discount rates. The most cost-effective option based on 6% discount rate is the 230kV Injection (Option a) following by SAT Transformation, 500kV Conversion, Phase Shifters and Reconductoring options respectively.

In conclusion, the most cost-effective option for CVIT reinforcement when considering the investment cost against the benefits from both reliability improvement and the loss reduction is the 230kV to 138kV Injection (Option a).

7. Conclusions

The Central Vancouver Island Transmission (CVIT) project is intended to resolve thermal constraints on the 138 kV system in Central Vancouver Island (circuits 1L115 and 1L116) as well as at the four 230/138 kV transformers at Vancouver Island Terminal Substation (VIT). Five main CVIT reinforcement options were considered in this study. Probabilistic reliability assessment and the transmission loss evaluation for the five CVIT reinforcement alternatives are presented in the report to provide a quantitative assessment of the reduction of the expected energy not supplied (EENS) and the loss reduction if the five different CVIT reinforcement alternatives would be implemented.

The results show that although the loss reduction benefit is quite significant for some CVIT reinforcement options, the reliability improvement benefit is however much more significant than the loss reduction benefit. This is due to the highly constrained Central VI system that needs to be resolved. The benefit/cost analysis was conducted in this report and the results indicate all the five reinforcement alternatives can be economically justified. However, the most cost-effective option for CVIT reinforcement is the 230kV Injection (Option a), as it offers the greatest NPV or BCR values, following by SAT Transformation, 500kV Conversion, Phase Shifters and Reconductoring options respectively.

References

[1] Wenyuan Li, "*MECORE Program: User's Manual*", British Columbia Transmission Corporation (BCTC), Canada, December 2001.

[2] Wenyuan Li, "*PLOSS Program: User's Manual*", British Columbia Transmission Corporation (BCTC), Canada, December 2001.

[3] R. Billinton, G. Wacker and G. Tollefson, *Assessment of Reliability Worth in Electric Power Systems in Canada*, NSERC Strategic Grant STR0045005, June 1993.

[4] Wenyuan Li, "*Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project: Part 4 - Effects of Existing HVDC on VI Power Supply Reliability", British Columbia Transmission Corporation (BCTC), Vancouver, Canada, January 9, 2006.*

Appendix A: Central and South Vancouver Island System

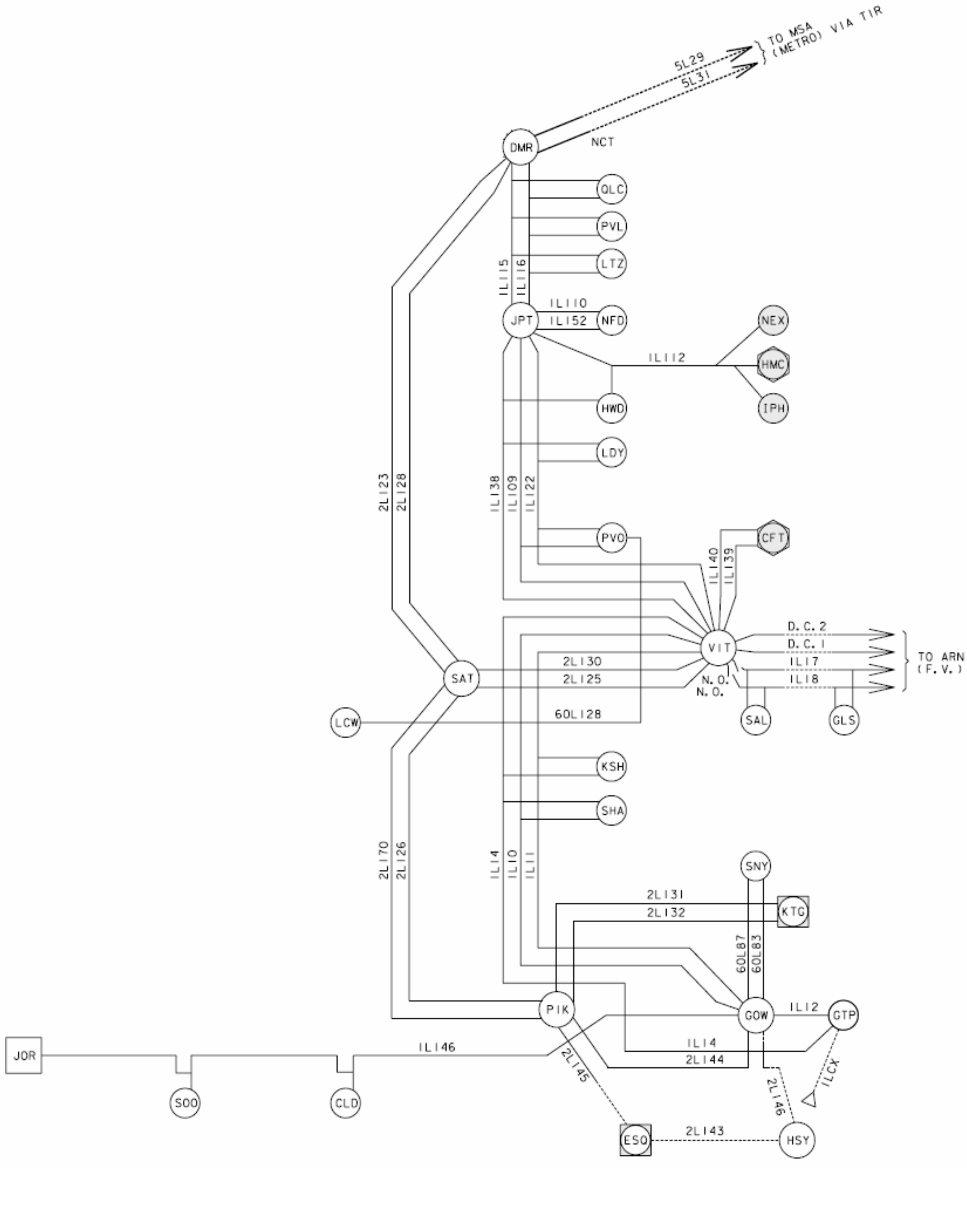

Figure A.1: Central and South Vancouver Island System Configuration (until 2009/10)

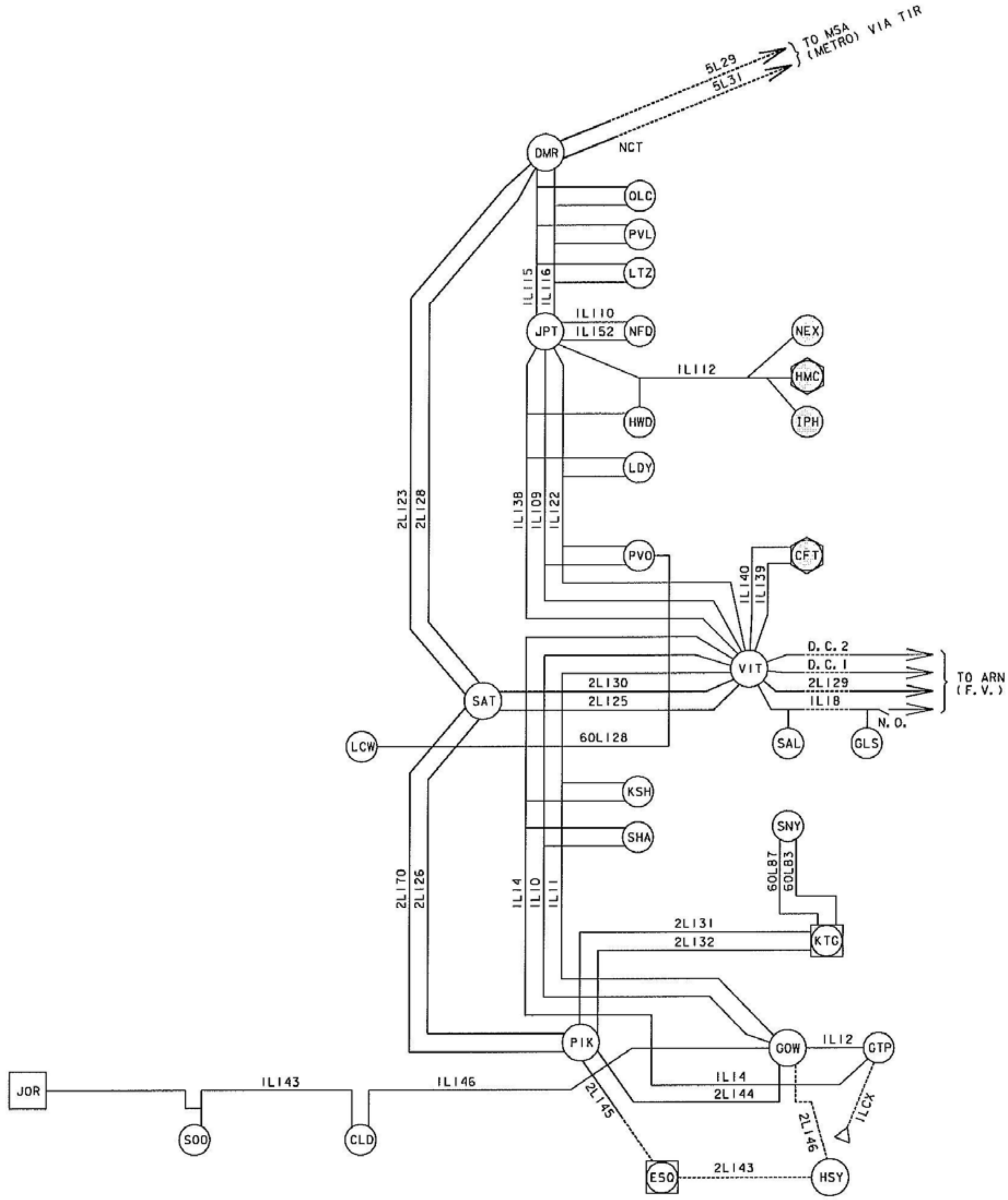

Figure A.2: Central and South Vancouver Island System Configuration (after 2009/10)

Appendix B: Vancouver Island Load Duration Curve

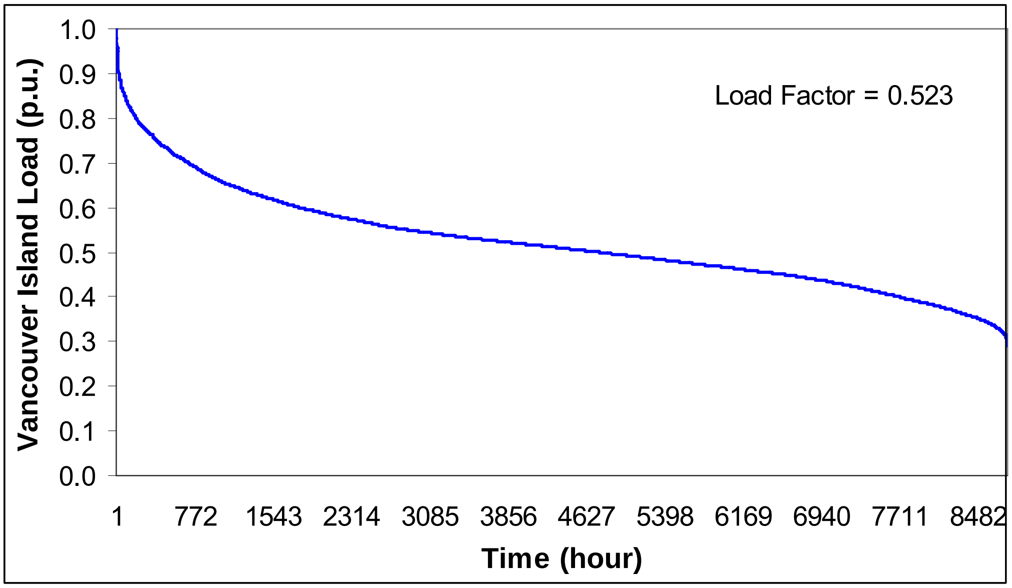

Figure B.1: Load duration curve for Vancouver Island System.

Appendix C: Substation Coincident Factors for Vancouver Island System

Table C1: Substation Coincident Factors for Winter and Summer Seasons

Bus Name (in RDMS)	Season Coincident Factors	
	Winter	Summer
APP138MA	0.9187	0.8707
BVC138SA	0.3204	0.3221
CBL25MA	0.9882	0.5647
CFT138MA	0.8550	0.8424
CLD25SA	0.9724	0.5538
CMX25MA	0.9849	0.9669
EFM138	0.8748	0.5212
ESQ12MA	0.9874	0.9058
GLD25MA	0.9472	0.6120
GLS25MA	0.8267	0.6120
GOW25MA	0.9637	0.4362
GRP138SA	0.8819	0.4123
GTP25MA	0.9852	0.5256
HMC138SA	0.3695	0.6744
HSY12MA	0.9809	0.5333
HSY25MB	0.9878	0.3509
HWD25MA	0.9846	0.6477
IPH138SA	0.2243	0.5282
JOR25MA	0.8722	0.5846
JUL138SB	0.9524	0.5644
JUL25SA	0.9439	0.4532
KGH25MA	0.9433	0.9528
KSH25MA	0.9404	0.4567
KTG25MA	0.9777	0.4566
LBH25SA	0.9397	0.6233
LBH25SB	0.9397	0.5136
LCW25SA	0.9661	0.4789
LDY25MA	0.9593	0.4789
LTZ25MA	0.9841	0.5614
NEX138SA	0.9823	0.6540
NFD25MA	0.9792	0.5410
OYR25MA	0.9807	0.9410
PAL25MA	0.9842	0.9836
PHY25SA	0.9474	0.5606
PML25SA	0.9474	0.5034
PUN25MA	0.9474	0.5953
PVL25MA	0.9897	0.4361
PVO25MA	0.9437	0.4362
QLC25MA	0.9730	0.4361
SAL25MA	0.9512	0.5222
SHA25MA	0.9719	0.4568
SNY25MA	0.9894	0.4782
SOO25SA	0.9437	0.5052
TSV25SA	0.9473	0.4757
WOS12SA	0.9489	0.5232

Appendix D: Jordan River Generation Pattern

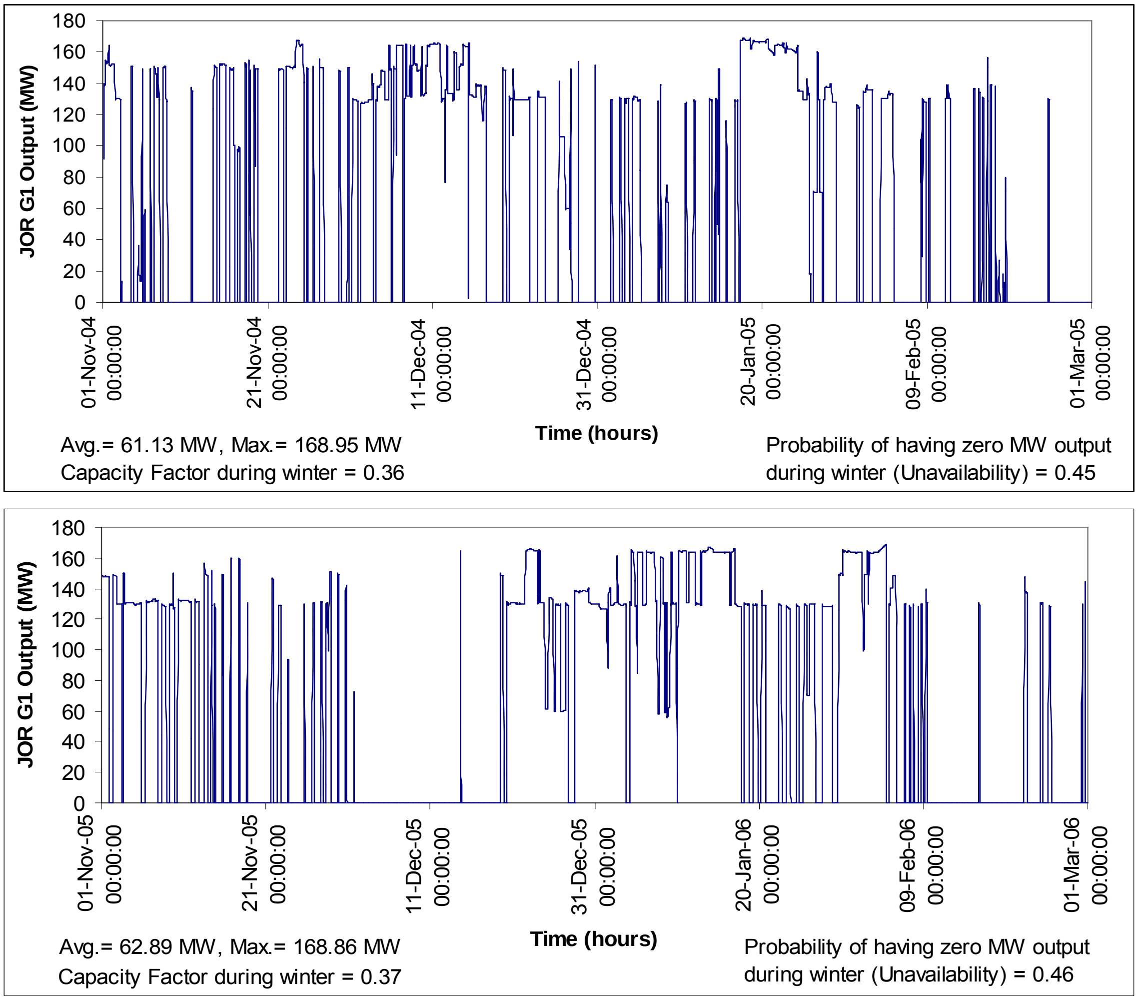

Figure D.1: MW Output of Jordan River generation during winter 2004/05 and 2005/06.

Appendix E: Unit Interruption Cost

A customer interruption cost survey was conducted by the Power System Research Group at the University of Saskatchewan with participation of all major Canadian utilities. This report was released in 1993 [3]. In this survey, a specific customer damage function for BC Hydro system was created and included in the “Capital Planning Guidelines” document of BC Hydro dated April 1, 1993. This customer damage function is shown in Table E.1. The customer damage functions shown in Table E.1 are expressed in $/kW with different outage durations. The mid value of each duration range is used to convert the $/kW value into the customer damage functions in $/kWh, which is shown in Table E.2.

Table E.1: Customer damage function for different customer sectors in $/kW.

Duration	Residential	Commercial	Industrial	Unknown mix
0 to 19 min.	0.2	11.4	5.5	1.9
20 to 59 min.	0.6	26.4	8.6	4.0
60 to 119 min.	2.8	40.1	19.6	8.5
120 to 239 min.	5.0	72.6	33.6	15.1
240 to 480 min.	7.2	147.6	52.1	26.5

Table E.2: Customer damage function for different customer sectors in $/kWh [4].

Duration	Residential	Commercial	Industrial	Unknown mix
10 min.	1.2	68.4	33.0	11.4
40 min.	0.9	39.6	12.9	6.0
90 min.	1.9	26.7	13.1	5.7
180 min.	1.7	24.2	11.2	5.0
360 min.	1.2	24.6	8.6	4.4
Average	**1.38**	**36.70**	**15.76**	**6.5**