PROBABILISTIC RELIABILITY ASSESSMENT
OF
QUALICUM SUBSTATION RECONFIGURATION

Report No. 2007-REL-02

Original: June 28, 2007

Revised: July 19, 2007

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 designated as 1L115 and 1L116 from Dunsmuir Substation (DMR) to Jingle Point Substation (JPT) are heavily loaded and are approaching their capacity limits during the high load in winter under system normal condition. The existing Qualicum Substation (QLC) configuration causes unbalanced flows on 1L115 and 1L116. Consequently, the thermal capability of the DMR-JPT path (1L115 and 1L116) is not maximized. Both 1L115 and 1L116 are equipped with a remedial action scheme that will trip both lines under overload conditions. The unbalanced flows on the 1L115 and 1L116 will therefore increases the likelihood of overload tripping of both 1L115 and under normal condition, which will result in load curtailment during high winter load even though there is no any system component being out of service.

The Qualicum Substation Reconfiguration project is intended to balance the flows on 1L115 and 1L116 in order that the likelihood of load curtailment due to overload tripping under normal condition is minimized until the Central Vancouver Island Reinforcement (CVIR) project is implemented to eliminate this constraint. The QLC Reconfiguration project will also help to reduce the magnitude of load curtailment to some extent if the in-service-date (2010) of the CVIR project is unexpectedly delayed. Probabilistic reliability assessment for the Qualicum Substation Reconfiguration project is presented in this report. The following findings are concluded in the report.

- *The likelihood and consequence of load curtailment due to the overload on 1L115 or 1L116 under system normal condition (no contingency) is quite significant. The Expected Energy Not Supplied (EENS) for 2008/09 – 2010/11 are 152.0, 252.0 and 614.4 MWh/yr respectively.*
- *When considering system normal and possible contingencies scenarios altogether, the benefit of QLC reconfiguration is very significant. The EENS reductions due to implementing this project are 863.4, 964.2 and 1010.2 MWh/yr in 2008/09 – 2010/11 respectively.*
- *The EENS reductions are converted to the monetized benefits and then be used in the benefit/cost analysis. Assuming that the project is 1 million and the unit interruption cost is 9.04 $/kWh. The benefit/cost ratio of this project is 15.1, which strongly indicates that this project is economically justified.*
- *The QLC reconfiguration will help to reduce the risk and consequence of load curtailment. However, if the in-service-date of CVIR is delayed beyond 2010, there still increases a significant risk that 1L115 and 1L116 will trip due to overload protection even if the QLC reconfiguration is already implemented.*

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Probabilistic Reliability Assessment for Qualicum Substation Reconfiguration

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1. Introduction

Central Vancouver Island 138 kV transmission circuits designated as 1L115 and 1L116 from Dunsmuir Substation (DMR) to Jingle Point Substation (JPT) are heavily loaded and are approaching their capacity limits during the high load in winter under system normal condition. The existing Qualicum Substation (QLC) configuration causes unbalanced flows on 1L115 and 1L116. Consequently, the thermal capability of the DMR-JPT path (1L115 and 1L116) is not maximized. Both 1L115 and 1L116 are equipped with a remedial action scheme that will trip both lines under overload conditions. The unbalanced flows on the 1L115 and 1L116 will therefore increases the likelihood of overload tripping of both 1L115 and 1L116 under normal condition, which will result in load curtailment during high winter load even though there is no any system component being out of service.

The Qualicum Substation Reconfiguration project is intended to balance the flows on 1L115 and 1L116 on the Central Vancouver Island in order that the likelihood of load curtailment due to overload tripping under normal condition is minimized until the Central Vancouver Island Reinforcement (CVIR) project is implemented. The Qualicum Substation Reconfiguration project will also reduce the magnitude of load curtailment to some extent if the in-service-date (2010) of the CVIR project is delayed.

Probabilistic reliability assessment for the Qualicum Substation Reconfiguration project is presented in the following sections.

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 – 2011) in Appendix A. The study does not focus on the Northern Vancouver Island system and it is therefore modeled as an equivalent load and generator connected to DMR substation.

- 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. CVIR project is assumed not to be in-service by October 2010 (to present the absolute risk in 2010/11).
- 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.
- Historical loading profile on 1L115 and 1L116 was obtained from PI system, and is shown in Figure B.2 in a similar form to a per unit load duration curve. It is important to note that the total flows on HVDC Poles 1 and 2 will have considerably impact on the flow pattern of 1L115 and 1L116, i.e. the higher flows through HVDC (greater than 600 MVA) are, the less flows on 1L115 and 1L116 could be expected. The impact of the HVDC flow pattern is therefore taken into account when modeling the flow pattern on 1L115 and 1L116.
- BC Hydro load forecast (2006/07 – 2016/17) was used in the study.
- Substation coincident factors for Vancouver Island system were considered in order to present the realistic situation in which all substation loads may not reach their peak loads at the same time. These substation 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.
- Remedial action scheme (RAS) to protect the overload on 1L115 and 1L116, which is limited by a winter rating at 194 MVA, is assumed to operate when the loading condition on either line reaches 208 MVA for longer than 11 minutes. This pick-up value (208 MVA) is based on the 1L115 and 1L116 Thermal Overload Relays under the 10 degree C. ambient temperature curve.

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) less than 1.2%.

4. Study Results

The expected energy not supplied (EENS) index is mainly focused in this 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 Qualicum Substation Reconfiguration project.

4.1 EENS under System Normal Condition Only

Table 4.1 shows the potential risk and magnitude of load curtailment and the EENS under system normal condition (no equipment out-of-service). The results were obtained from the load flow program, PSS/E, associated with the historical loading pattern of 1L115 and 1L116 as shown in Figure B.2. The per unit loading pattern of 1L115 and 1L116 was scaled up to match with the load forecast.

Under normal condition, if the loading condition on either 1L115 or 1L116 tends to be greater than 208 MVA, partial load at QLC will assumed be curtailed in advance to the operation of the RAS. It is very important to note that this assumption is relatively optimistic. This is due to the fact that if the RAS operation is initiated to protect the line overload, the opened ends of 1L115 and 1L116 at JPT will occur and thus will result in overloads on VIT transformers. The load curtailment will be required to alleviate the VIT transformer overloads, which could be more severe than curtailing the partial load at QLC before the RAS operates.

Table 4.1: Potential risk due to unbalanced flows on 1L115 and 1L116 (the existing system) under system normal condition (no equipment out-of-service)

Year	Expected Maximum Loading on 1L115 or 1L116 (MVA)	Expected Load Curtailment at QLC (MW)	Expected Overload Hours (hours)	Probability of Overload	EENS (MWh/yr)
2008/09	220.1	14.0	11.0	0.0013	154.0
2009/10	221.4	18.0	14.0	0.0016	252.0
2010/11	227.4	25.6	24.0	0.0027	614.4

The implementation of QLC reconfiguration project will help in balancing the flows on 1L115 and 1L116, and therefore will reduce the likelihood of RAS to be operated. In other word, the potential of overload on either 1L115 or 1L116 under system normal condition will be eliminated/reduced. The potential risks under system normal condition after balancing the flows on 1L115 and 1L116 are presented in Table 4.2.

Table 4.2: Potential risk after balancing the flows on 1L115 and 1L116 (QLC reconfiguration implemented) under system normal condition (no equipment out-of-service)

Year	Expected Maximum Loading on 1L115 or 1L116 (MVA)	Expected Load Curtailment at QLC (MW)	Expected Overload Hours (hours)	Probability of Overload	EENS (MWh/yr)
2008/09	205.6	0.0	0.0	0.0000	0.0
2009/10	206.5	0.0	0.0	0.0000	0.0
2010/11	212.3	11.8	5.0	0.0006	59.0

Table 4.2 indicates that there is no potential of load curtailment in 2008/09 and 2009/10 when all equipment is in-service as the expected maximum loading on 1L115 and 1L116 is less than the picked-up value of RAS operation, which is 208 MVA. However, there is still a potential of load curtailment under system normal condition in 2010/11 when the expected maximum loading on the 1L115 and 1L116 is beyond 208 MVA. In order to avoid load curtailment under system normal condition in 2010/11, the real time operator may need to adopt a preventive action to protect overload on 1L115 and 1L116 by opening the end of 1L138 at JPT and then supplying HWD load

by a single source from VIT. This action will reduce the flows on 1L115 and 1L116. However, this preventive action should be used during a very heavy load condition only, i.e. when actual load is beyond 90% of the load forecast (there are not many hours in a year) because this preventive action will increase the loadings on the four VIT transformers that would result in a greater load curtailment if the forced outage on one of VIT transformers occurs during that time.

The benefit of QLC reconfiguration can be seen from the reduction of EENS resulting from Tables 4.1 and 4.2. The EENS reduction (ΔEENS) in 2008/09 and 2009/10 are equal to 154.0 and 252.0 MWh/yr respectively. The ΔEENS in 2010/11 is equal to (614.4 – 59.0) or 555.4 MWh/yr.

It is important to note that if the Central Vancouver Island Reinforcement (CVIR) project cannot be in-service by 2010/11, the potential risk of load curtailment under system normal condition will considerably increase. To prevent significant load curtailment due to RAS operation when the in-service-date of the VCIR project is unexpectedly delayed, opening end of 1L138 at JPT, and then transferring HWD load to 1L138 as noted above could be adopted. This preventive action however will result in heavier loading on the VIT transformers and further increase the risk of load curtailment under contingency situations. Therefore, opening end of 1L138 at JPT should be carefully implemented.

4.2 EENS under System Normal and Possible Contingencies

The EENS results presented in Tables 4.1 and 4.2 are based on the system under normal condition only. When considering possible contingencies on the Central and South Vancouver Island system, the EENS will be considerably higher than those shown in Tables 4.1 and 4.2. Tables 4.3 and 4.4 respectively show the EENS before and after QLC reconfiguration. These results were obtained using MECORE software, which considers system normal condition and possible contingencies associated with their probabilities of occurring.

Table 4.3: EENS in MWh/yr based on the existing QLC configuration (unbalanced flows on 1L115 and 1L116) when considering possible contingencies and system normal condition

Year	Potential Risks Calculated by Season		Total Annual Risk (MWh/yr)
	Winter (MWh/winter period)	Summer (MWh/summer period)	
2008/09	3792.38	802.80	4595.18
2009/10	4363.25	854.70	5217.95
2010/11	4374.34	850.59	5224.93

Table 4.4: EENS in MWh/yr based on the QLC re-configuration (balanced flows on 1L115 and 1L116) when considering possible contingencies and system normal condition

Year	Potential Risks Calculated by Season		Total Annual Risk (MWh/yr)
	Winter (MWh/winter period)	Summer (MWh/summer period)	
2008/09	3045.28	686.50	3731.77
2009/10	3513.63	740.07	4253.70
2010/11	3485.80	728.92	4214.72

Note that the EENS for 2010/11 shown in Tables 4.3 and 4.4 are relatively similar to those for 2009/10. This is due to the fact that the Retermination of Sidney to Keating project will be in-service in 2010. This project will help to alleviate constraints on the 138 kV system.

The overall benefit of the QLC reconfiguration project can be seen in a form of EENS reduction, which can be obtained from Tables 4.3 and 4.4. The EENS reduction is presented in Table 4.5.

Table 4.5: The EENS reduction (ΔEENS) due to the QLC re-configuration

Year	System Configuration		ΔEENS (MWh/yr)
	Before QLC Re-configuration	After QLC Re-configuration	
2008/09	4595.18	3731.77	**863.41**
2009/10	5217.95	4253.70	**964.25**
2010/11	5224.93	4214.72	**1010.21**

5. Benefit/Cost Analysis

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 [2] are used in this approach. The UIC in $/kWh can be derived from the customer damage function and was used in Appendix E [3]. 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 5.1.

The last row in Table 5.1 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 QLC re-configuration project.

Table 5.1: Customer load composition and composite unit interruption cost (UIC) for the Central and South VI substations

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 (ΔEENS) can be monetized and be presented as the reduction of the expected damage cost (ΔEDC), which can be obtained from the multiplication of the specified unit interruption cost (9.04 $/kWh) and the ΔEENS shown in Table 4.5. The monetized benefit (ΔEDC) of QLC re-configuration project is shown in Table 5.2.

Table 5.2: The monetized benefit (EDC reduction) due to the QLC re-configuration

Year	ΔEDC (M$/yr)
2008/09	7.805
2009/10	8.717
2010/11	9.132

Given that the capital cost for QLC re-configuration project is $1.0 million (a ball park cost estimate at the time of this study). The project will include converting the QLC to Jones-type station, adding reactors and protection facilities. In economic analysis for the QLC re-configuration project, let us assume that:

- The economic useful time of the project is 2 years (2008/09 – 2009/10) assuming CVIR project will be in-service by October 2010. Note that this 2 year period is for study purpose. The true benefit (maximizing the path utilization) of this project will considerably greater than 2 years.
- The discount rate is 6%.

The capital return factor is therefore equal to:

Capital return factor (CRF) = $\frac{i(1+i)^n}{(1+i)^n - 1} = \frac{0.06(1+0.06)^2}{(1+0.06)^2 - 1}$ = 0.54544

The annual capital payment (ACP) for the QLC re-configuration project can be calculated using the multiplication of the total capital cost and the capital return factor.
Annual capital payment for the line upgrade project = 1.0×0.54544 = 0.545 M$/yr

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 for 2008/09 to 2009/2010 are shown in Table 5.3 together with the monetized benefit (ΔEDC) due to the QLC re-configuration project.

Table 5.3: The monetized benefit (ΔEDC) and the annual capital payment (ACP) in M$/yr for QLC re-configuration project during 2008/09 – 2009/10

Year	ΔEDC (benefit gained)	ACP (cost spent)
2008/09	7.805	0.545
2009/10	8.717	0.545

The present value (PV) based on 2007 for both benefits and costs shown in Table 5.3 can be calculated using the following equation (using the discount rate of 6%):

PV of the total ΔEDC = $\sum_{j=1}^{m} \frac{\Delta EDC_j}{(1+0.06)^{j-1}}$, and PV of the total ACP = $\sum_{j=1}^{m} \frac{ACP_j}{(1+0.06)^{j-1}}$

Where: m = planning period (i.e. 2 years in this case).

Therefore,

- Present value of the total ΔEDC = $15.121 million
- Present value of the total ACP = $0.999 million
- The benefit/cost ratio (BCR) = 15.121/0.999 = 15.136

The benefit/cost ratio for the QLC re-configuration project are greater than 1.0. This implies that the QLC re-configuration project has the economic justification based on the reliability benefit/cost analysis.

6. Conclusions

The central Vancouver Island 138 kV system is constrained, and the Central Vancouver Island Reinforcement (CVIR) project is being considered. The CVIR project however requires a long lead time of construction and cannot be in service sooner than 2010. The Qualicum Substation Re-configuration project will help in balancing the flows on 1L115 and 1L116 and therefore maximize the utilization of Central VI 138 kV path from DMR to JPT. If the QLC reconfiguration project is not implemented soon, the likelihood of load curtailment triggered by remedial action scheme (RAS) under system normal condition will considerably increase. Balancing the flows on 1L115 and 1L116 will significantly reduce the risk of load curtailment from the operation of RAS that protects the overload on 1L115 and 1L116. The probabilistic reliability assessment is presented in this report to assess the risk of load curtailment under system normal condition and possible contingencies. The results shown in this report indicate that the benefit of the QLC re-configuration project in term of EENS reduction is significant, and thus the monetized benefit is substantial. The benefit/cost ratio is considerably greater than 1.0 which indicates this project has an economic justification.

References

[1] Wenyuan Li, "*MECORE Program: User's Manual*", BC Hydro, Canada, December 2001.

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

[3] 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

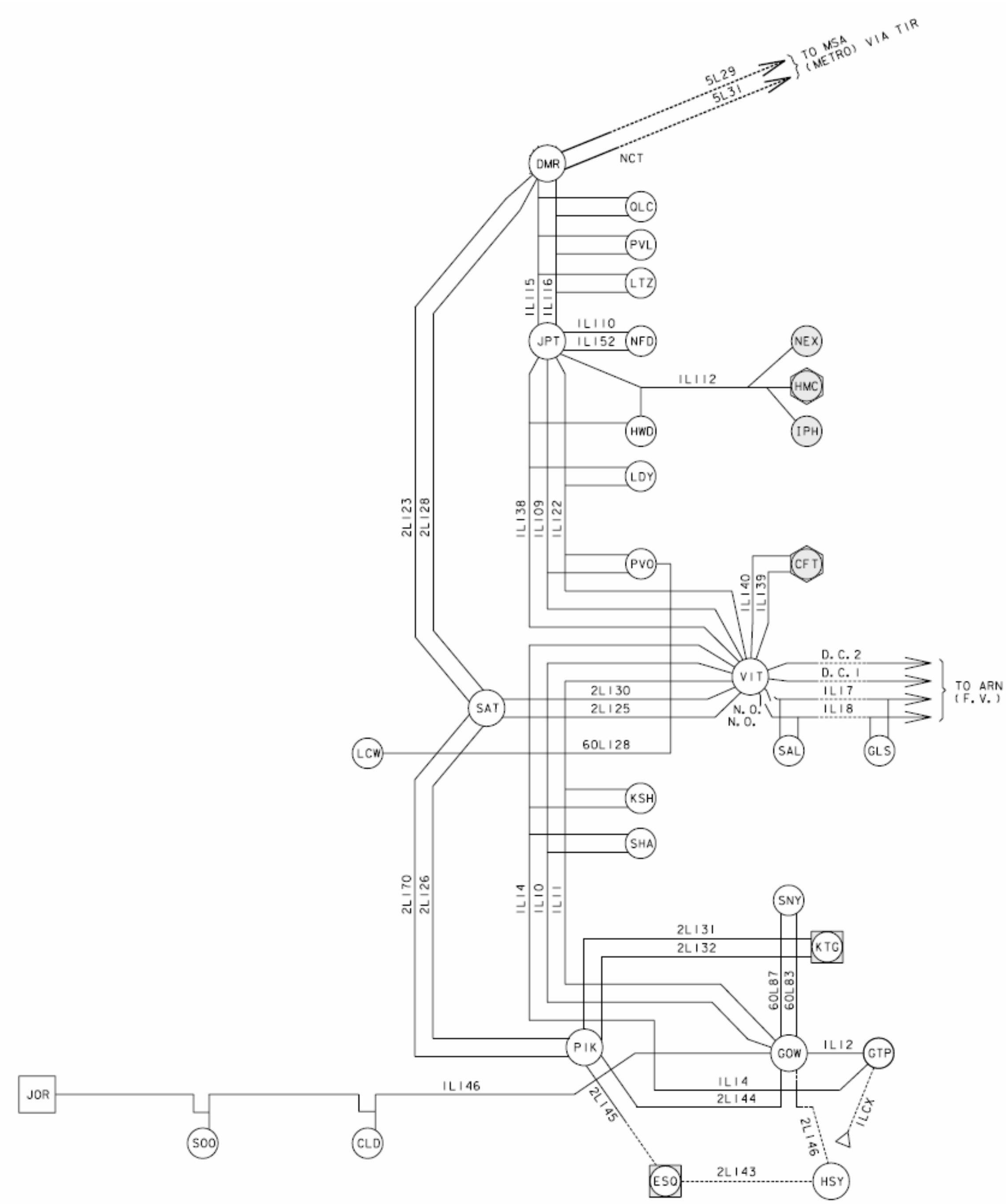

Figure A.1: Central and South Vancouver Island System Configuration (until 2009/10)

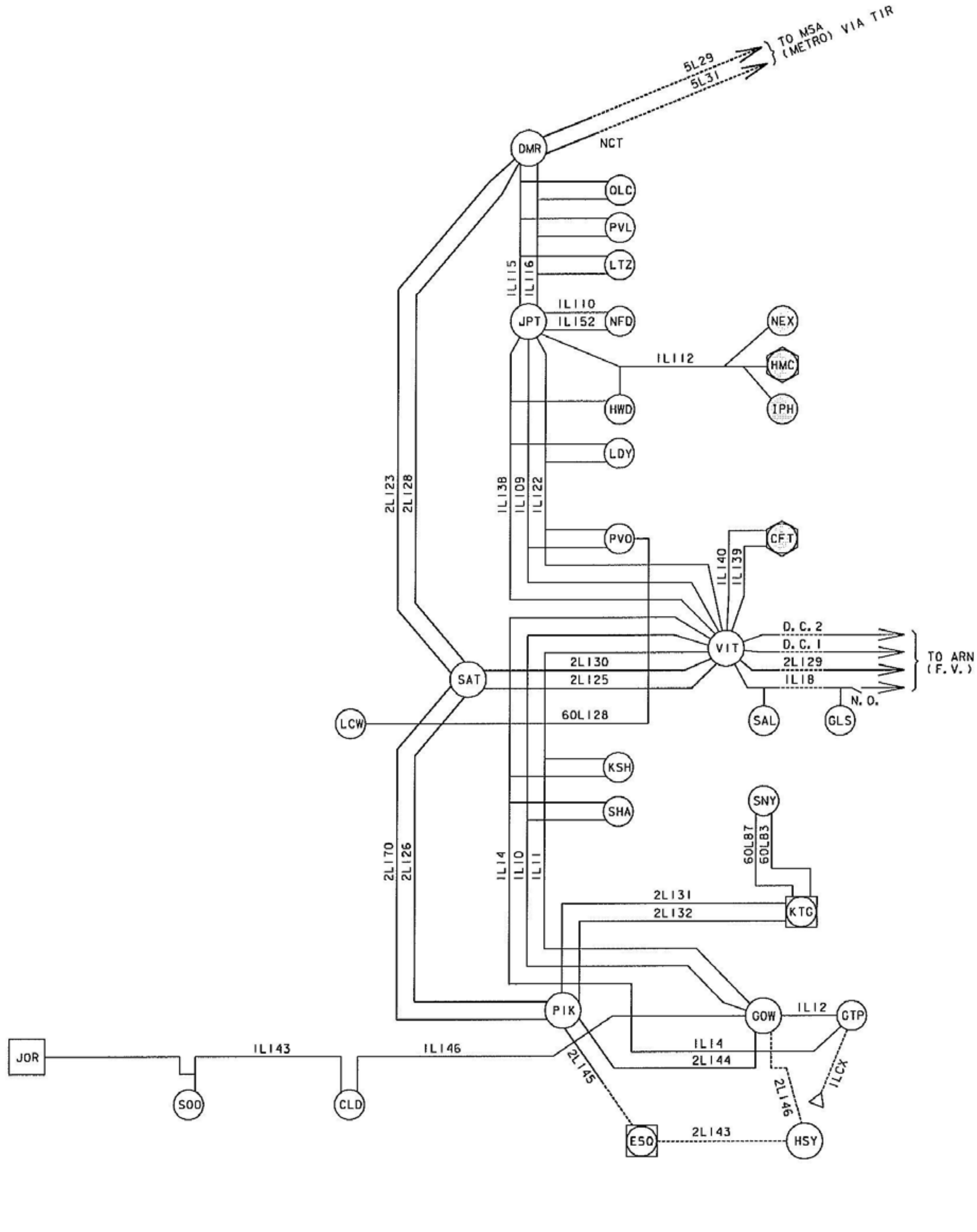

Figure A.2: Central and South Vancouver Island System Configuration (after 2010/11)

Appendix B: Vancouver Island Load Duration Curve and Loading Pattern on 1L115 and 1L116

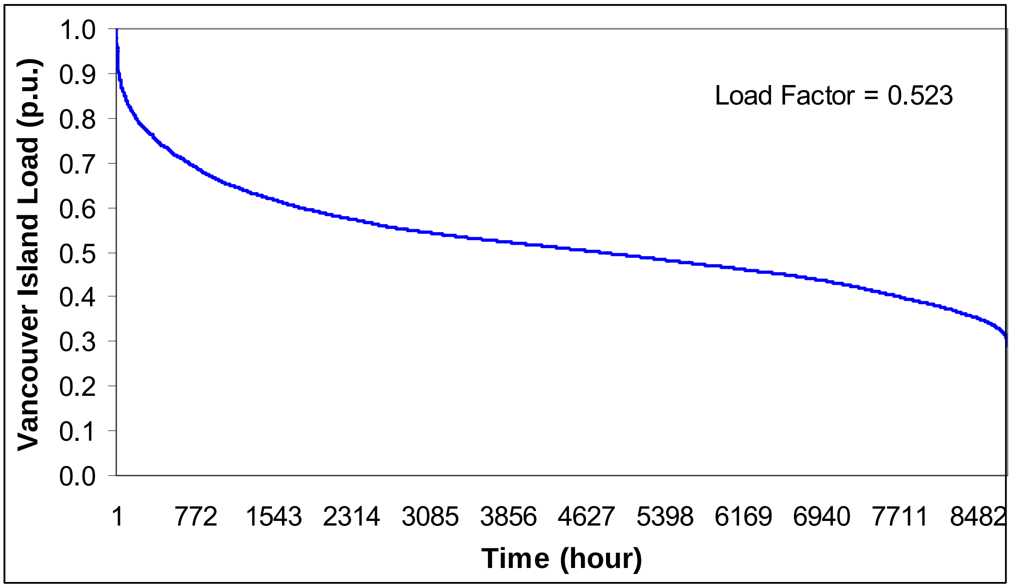

Figure B.1: Load duration curve for Vancouver Island System.

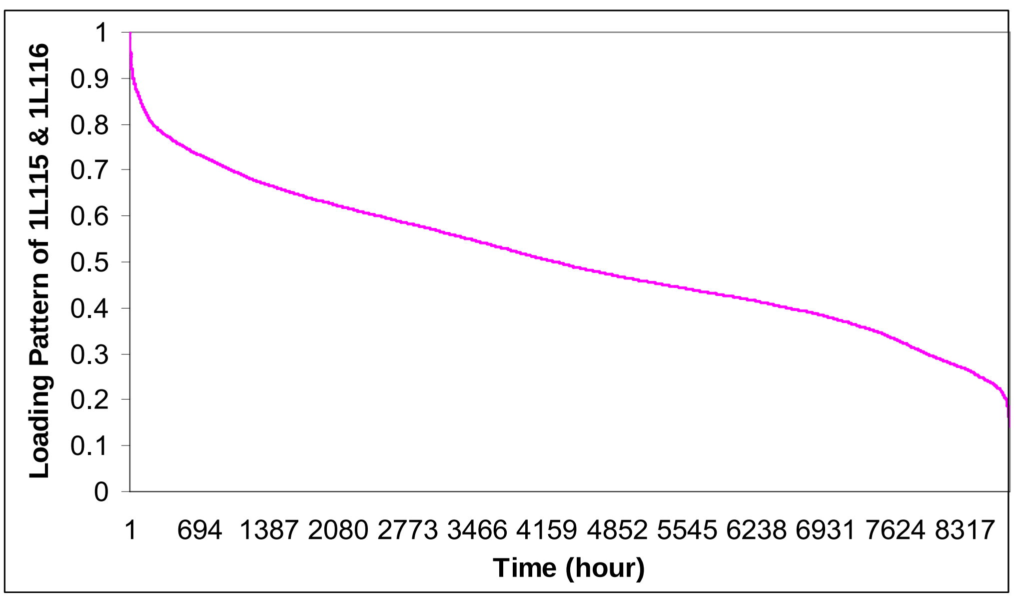

Figure B.2: Loading Pattern on 1L115 and 1L116.

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

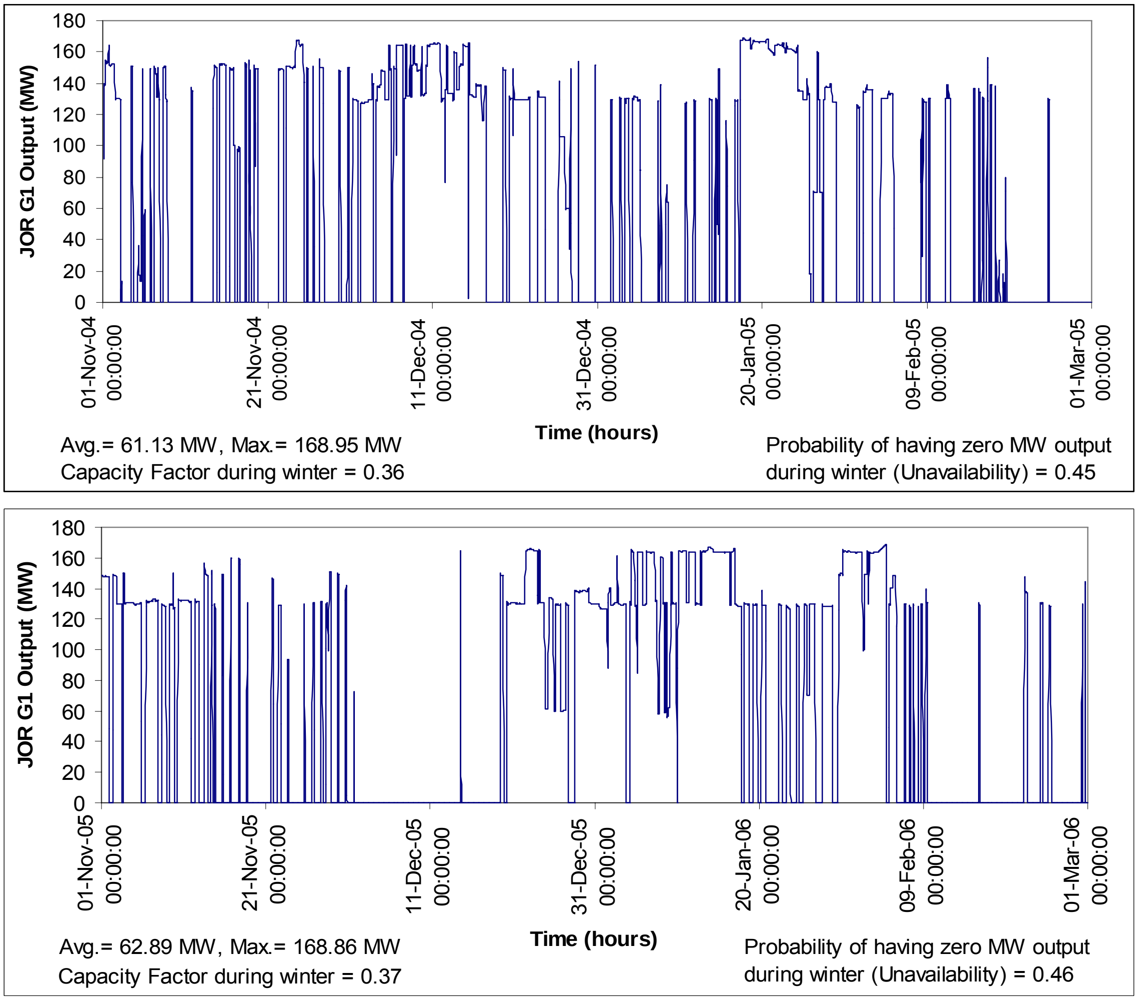

Figure D.1: MW Output of Jordan River generation during winter 2004/05 and 2005/06.

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 [2]. 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.

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**