March 27, 2006

Reliability Assessment of Cathedral Square Substation

(Executive Summary)

Prepared by: Wijarn Wangdee
Regional System Planning, SPPA
British Columbia Transmission Corporation

There is a considerable concern in regard to a reliability of Cathedral Square Substation. This is due to a uniqueness of this underground substation serving 30% of all downtown loads. There are two existing transformers at this substation. A loss of any transformer will involve a considerable time (up to 2 years) to replace it, or the transformer has to be taken above the ground if it is required a major repair.

The questions for the reliability improvement of Cathedral Square Substation are:

- Should the third transformer be added?
- If yes, will this transformer addition project be justified?

This report performs a reliability assessment of Cathedral Square Substation during a ten years period (2006 – 2015). End-of-life failures, planned and forced outages are taken into account in this study. The cost/benefit analysis is also presented in this report to facilitate a reinforcement project justification process.

The results indicate that:

- The end-of-life failures could have a considerable impact on the substation reliability. Due to the limited data to calculate a mean life and standard deviation of the mean life for transformers, a sensitivity study using three different scenarios has been demonstrated. These three cases (Base Case, Modified Case and U.S. Case) are used to represent the best to worst case scenarios respectively.
- When the third transformer is added to the substation, a reliability of substation significantly improves. The impact of end-of-life failures on the substation reliability becomes relatively very little when the third transformer is installed.
- There are two interruption cost models used in this report. They are designated as the GDP-based interruption cost and customer-based survey interruption cost approaches. The interruption cost model selection can directly have a significant influence on the project justification.

The recommendations are:

- When considering the economy-sensitive loads in downtown Vancouver, the use of the customer-based survey interruption cost model should be suitable in reflecting the monetary impact of different customer types due to power outages.
- If the customer-based survey interruption cost model is utilized, there is no need to add the third transformer for the Base Case (too optimistic scenario). A transformer addition should be immediately implemented without delay for the Modified Case (moderate scenario) and for the U.S. Case (pessimistic scenario).

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1. Introduction

Cathedral Square (CSQ) Substation is the only underground substation in BC Hydro system which is located at Homer and Dunsmuir and is supplied from Murrin and Payne substations through three transmission circuits, 2L31/32/33. The substation serves Vancouver's main financial and commercial district, and supplies about 30% of all downtown loads. Loss of supply at the substation would have a significant impact on the customer monetary loss. There are three probable causes in loss of supply at the CSQ substation, which are described as follows:

- A complete loss of transmission supply
- A complete loss of 230/12 kV transformation
- Seismic damages

The CSQ substation is connected to three 230 kV transmission circuits, which each one is capable of supplying the total substation load. A complete loss of transmission supply is therefore considerably rare. In the unlikely event that all transmission circuits are lost, at least one of the circuits could be quickly returned to service by switching to supply load.

In the case of seismic risks, both the CSQ substation and a circuit 2L33 meet current BC Hydro seismic standards. Consequently, the substation should survive under a severe seismic event and be able to continue supplying the load.

The substation has two 230/12 kV transformers, which have been in operation since 1984. Each transformer is capable of supplying the total forecast station load demand. The CSQ substation meets the N-1 planning criterion when a failed unit can be returned in service with a reasonable duration. However, a reasonable outage time under the N-1 criterion cannot be applied in case of an aging failure situation. Since the transformers are in underground, the removal and re-installation of a transformer at the substation are considerably a tedious task and a lengthy process. The major repair time or replacement time for the damaged unit could take up to 19 – 24 months. If a remaining unit is forced out of service while replacing the aged (end of life) transformer, there will be a complete loss of supply at the substation. The substation would, therefore, be at a high risk during the long replacement process period. The remaining unit cannot be taken out of service for a routine maintenance during that period. A lack of maintenance could potentially increase the failure rate of the remaining unit. This report investigates the substation risk involving the loss of both transformers and examines the benefit of an additional transformer installation at the CSQ substation in order to mitigate the risk.

2. Reliability Analysis of Double Transformers

The terminal related failures are assumed to have only relatively little impact on an overall system reliability, and therefore are not considered in this report. Without taking terminal related failures into account, both transformers at the CSQ substation can be simply considered as a parallel system shown in Figure 1.

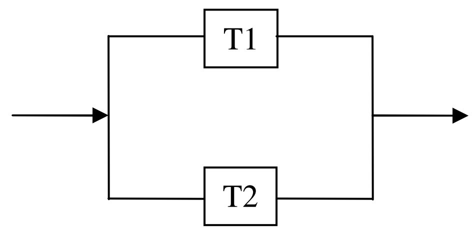

Figure 1: A parallel system representing both transformers at CSQ substation.

In power system reliability analysis, there are two fundamental failure modes for a power system components designated as "repairable" and "non-repairable" failures [1, 2]. These two failure modes are described in the following sections.

2.1 Repairable Failures

Repairable failure modes are basically related to "forced" and "planned" outages. Forced outage refers to an unanticipated failure which is random in nature and therefore involved with uncertainties. Planned outage refers to a component being taken out of service for maintenance at a specified or certain time. Since both transformers at CSQ substation were manufactured by the same manufacturer (Hyundai) and are of the same age and design, the planned outage records of both transformers are therefore merged and averaged. The forced outage parameters were calculated from the outage statistics of BC Hydro 230/12 kV and 230/25 kV 150MVA transformers in the Lower Mainland area. All these limited historical data were obtained from CROW (Control Room Operations Window) system and summarized in Table 1. Table 1 shows the planned outage failure rate and repair time of both transformers (CSQ T1 and CSQ T2) based on the available data from 2003 – 2005, and also presents the average forced outage failure rate and repair time of the similar type of transformers utilized at CSQ substation based on the available from 1994 – 2003.

Table 1: Planned and forced outage parameters of both transformers at CSQ substation.

Type of Outages	CSQ T1		CSQ T2	
	failure rate, λ (failures/yr)	repair time, r (hours)	failure rate, λ (failures/yr)	repair time, r (hours)
Planned	1.67	30.11	1.67	30.11
Forced	0.05	29.78	0.05	29.78

2.2 Non-Repairable Failure (End-of-Life or Aging Failures)

As shown in the previous section, repair times for a repairable failure mode are normally short. This is unlikely the case for a non-repairable failure mode involving with transformers at the CSQ substation. The transformers could suffer from end-of-life (aging) failures, and the replacement time could take up to 19 – 24 months. Even though end-of-life failure is random in nature, a probability of failure increases with the age of the transformer unit. An in-house software designated as SPARE [3] is used to estimate the probability of the aging failure. The SPARE program generates the failure rate (λ) based on the mean life and standard deviation and the number of in-service years of a device.

The number of 230 kV transformer population used in this analysis is 69 and the number of retired transformers in this population is 3. The mean life and standard deviation for this transformer population were obtained from an in-house software designated as MeanLife. The results obtained from the MeanLife software show that the mean life and standard deviation of this group of transformers are 48.1 years and 5.6 years respectively.

Table 2 shows aging failure rates for CSQ T1 and CSQ T2 from the year 2006 – 2012 obtained from the MeanLife software using the mean life of 48.1 years and standard deviation of 5.6 years. Table 2 shows that the aging failure increases with the year in service The replacement time of the transformer is 13870 hours (19 months) is also presented in Table 2.

Table 2: Aging outage parameters of both transformers at CSQ substation.

Type of Outage	Year	CSQ T1		CSQ T2	
		failure rate, λ (failures/yr)	replacement time, r (hours)	failure rate, λ (failures/yr)	replacement time, r (hours)
End of Life (Aging)	2006	0.00001	13870	0.00001	13870
	2007	0.00002	13870	0.00002	13870
	2008	0.00003	13870	0.00003	13870
	2009	0.00004	13870	0.00004	13870
	2010	0.00007	13870	0.00007	13870
	2011	0.00010	13870	0.00010	13870
	2012	0.00015	13870	0.00015	13870

3. Reliability Calculation

As shown in Figure 1, both CSQ transformers can be considered as a parallel system. The parallel system will be in a failure state only when both transformers fail at the same time.

The failure modes for a parallel system shown in Figure 1 can be broadly categorized as follows:

Without Aging Factor:

1. One planned outage transformer and one forced outage transformer.
2. Both transformers are forced out of service.

With Aging Factor:

3. One planned outage transformer and one aging outage transformer.
4. One forced outage transformer and one aging outage transformer.
5. Two aging outage transformers.

Let λ = Forced failure rate (failures/year),
λ^p = Planned failure rate (failures/year),
λ^a = Aging failure rate (failures/year),
r = Repair time for a forced outage (hours),
r^p = Repair time for a planned outage (hours),
r^a = Replacement time (hours),
f = Forced failure frequency (failures/year),
f^p = Planned failure frequency (failures/year),
f^a = Aging failure frequency (failures/year).

Where: $f = \dfrac{\lambda}{1+\dfrac{\lambda r}{8760}}$, $f^p = \dfrac{\lambda^p}{1+\dfrac{\lambda^p r^p}{8760}}$, and $f^a = \dfrac{\lambda^a}{1+\dfrac{\lambda^a r^a}{8760}}$

The failure rate (λ) shown in Table 1 were directly calculated from the historical outage statistics. Failure frequency (f) is not only related to the failure rate, but also taken the repair time into account during a specified period. If the repair time is considerably short, the λr factor will become relatively small. When the λr factor is much less than 1, the failure rate (λ) can therefore be approximately utilized as the failure frequency (f).

The five general failure categories noted above can be described in details as follows:

1.	**One planned outage transformer and one forced outage transformer.**		
1.1	T1 planned, then T2 forced	$f_{p(1.1)} = f_2\left(f_1^p r_1^p\right)$	$r_{p(1.1)} = \dfrac{r_2 r_1^p}{r_2 + r_1^p}$
1.2	T2 planned, then T1 forced	$f_{p(1.2)} = f_1\left(f_2^p r_2^p\right)$	$r_{p(1.2)} = \dfrac{r_1 r_2^p}{r_1 + r_2^p}$
2.	**Both transformers are forced out of service.**		
2.1	T1 forced, then T2 forced	$f_{p(2.1)} = f_2\left(f_1 r_1\right)$	$r_{p(2.1)} = \dfrac{r_2 r_1}{r_2 + r_1}$
2.2	T2 forced, then T1 forced	$f_{p(2.2)} = f_1\left(f_2 r_2\right)$	$r_{p(2.2)} = \dfrac{r_1 r_2}{r_1 + r_2}$
3.	**One planned outage transformer and one aging outage transformer.**		
3.1	T1 planned, then T2 aging	$f_{p(3.1)} = f_2^a\left(f_1^p r_1^p\right)$	$r_{p(3.1)} = \dfrac{r_2^a r_1^p}{r_2^a + r_1^p}$
3.2	T2 planned, then T1 aging	$f_{p(3.2)} = f_1^a\left(f_2^p r_2^p\right)$	$r_{p(3.2)} = \dfrac{r_1^a r_2^p}{r_1^a + r_2^p}$
4.	**One forced outage transformer and one aging outage transformer.**		
4.1	T1 forced, then T2 aging	$f_{p(4.1)} = f_2^a\left(f_1 r_1\right)$	$r_{p(4.1)} = \dfrac{r_2^a r_1}{r_2^a + r_1}$
4.2	T2 forced, then T1 aging	$f_{p(4.2)} = f_1^a\left(f_2 r_2\right)$	$r_{p(4.2)} = \dfrac{r_1^a r_2}{r_1^a + r_2}$
4.3	T1 aging, then T2 forced	$f_{p(4.3)} = f_2\left(f_1^a r_1^a\right)$	$r_{p(4.3)} = \dfrac{r_2 r_1^a}{r_2 + r_1^a}$
4.4	T2 aging, then T1 forced	$f_{p(4.4)} = f_1\left(f_2^a r_2^a\right)$	$r_{p(4.4)} = \dfrac{r_1 r_2^a}{r_1 + r_2^a}$
5.	**Two aging outage transformers.**		
5.1	T1 aging, then T2 aging	$f_{p(5.1)} = f_2^a\left(f_1^a r_1^a\right)$	$r_{p(5.1)} = \dfrac{r_2^a r_1^a}{r_2^a + r_1^a}$
5.2	T2 aging, then T1 aging	$f_{p(5.2)} = f_1^a\left(f_2^a r_2^a\right)$	$r_{p(5.2)} = \dfrac{r_1^a r_2^a}{r_1^a + r_2^a}$

Where: $f_{p(\ )}$ and $r_{p(\ )}$ respectively are the failure frequency and the repair time of the parallel system under specified outage scenarios.

Unavailability of the parallel system (U_p) can be expressed as:

$$U_p = \sum f_p r_p \qquad \text{(hours/year)} \qquad (1)$$

Expected Energy Not Supplied (EENS) can be obtained by a product of Unavailability (U_p) and load demand (L) in MW.

$$EENS = L \times U_p \qquad (MWh/yr) \qquad (2)$$

Expected Damage Cost (EDC) represents a customer monetary loss and is a surrogate for reliability worth. Expected Damage Cost can be obtained by a product of EENS and an unit interruption cost (UIC). This unit interruption cost ($/kWh) has a similar meaning to Interrupted Energy Assessment rate (IEAR) or Value of Lost Load (VoLL) widely used in UK. The unit interruption cost (UIC) of $3.07/kWh is used in this section. This rate is obtained from the ratio of the Provincial Gross Domestic Product (GDP) to the annual energy consumption as shown below:

The provincial GDP at market prices for 2004 is $157.241 Billion [4]
The total electricity energy domestic consumption for 2004/2005 is 51,205 GWh [5]
The unit interruption cost is: 157.241e9/51.205e9 = $3.07/kWh

$$EDC = EENS \times UIC \qquad (\$M/yr) \qquad (3)$$

Load Duration Curve (LDC) for CSQ substation obtained from PI data during March 2005 – February 2006 is shown in Figure 2. The data shown in Figure 2 are based on hourly average values (8760 values).

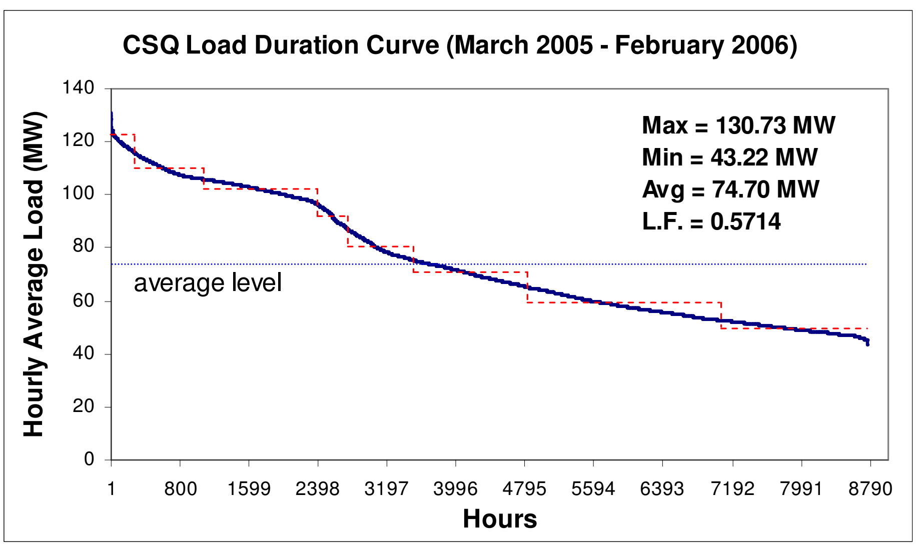

Figure 2: Load duration curve (LDC) for CSQ substation during March 2005 – February 2006.

Figure 2 shows that the load factor (L.F.) for CSQ substation is 0.5714. Assume that the load shape will be similar to that shown in Figure 2 for the next 10 years. The 10 years peak load forecast in MVA is shown in Table 3. Power factor (P.F.) at CSQ substation is approximately 0.92. The yearly peak load forecast in MW can then be calculated and shown in Table 3. The average load in MW can be obtained by multiplying the load factor (L.F. = 0.5714) to the yearly peak load demand (MW).

Table 3: 10 years load forecast for CSQ substation.

Year	Peak Load Forecast (MVA)	Peak Load Forecast (MW)	Average Load Forecast (MW)
2006	161.70	148.76	85.00
2007	180.90	166.43	95.10
2008	191.10	175.81	100.46
2009	194.50	178.94	102.25
2010	195.90	180.23	102.98
2011	198.00	182.16	104.09
2012	200.10	184.09	105.19
2013	197.20	181.42	103.67
2014	199.40	183.45	104.82
2015	196.40	180.69	103.25

The reliability analysis results based on the data presented in Tables 1 and 2 incorporated with the calculation models in Equations (1) – (3) are summarized in Table 4. The results shown in Table 4 are designated as a base case which will be used to compare against with other cases for sensitivity study.

Table 4: A summary of reliability analysis results of CSQ substation (Base Case)

Year	Unavailability (U_p), hrs/yr			Average Load (MW)	EENS (MWh/yr)	EDC ($M/yr)
	No Aging (mode: 1&2)	*With Aging (mode: 3-5)*	Total *(1-5)*			
2006	*0.0088*	*0.0001*	0.0088	85.00	0.75	0.002
2007	*0.0088*	*0.0001*	0.0089	95.10	0.85	0.003
2008	*0.0088*	*0.0002*	0.0090	100.46	0.90	0.003
2009	*0.0088*	*0.0002*	0.0090	102.25	0.92	0.003
2010	*0.0088*	*0.0005*	0.0093	102.98	0.95	0.003
2011	*0.0088*	*0.0007*	0.0095	104.09	0.99	0.003
2012	*0.0088*	*0.0013*	0.0100	105.19	1.06	0.003
2013	*0.0088*	*0.0020*	0.0108	103.67	1.12	0.003
2014	*0.0088*	*0.0037*	0.0125	104.82	1.31	0.004
2015	*0.0088*	*0.0065*	0.0153	103.25	1.58	0.005

Table 4 shows that at the early year of the study, i.e. 2006, the unavailability due to an aging failure is relatively very little compared to the traditional unavailability (considering only planned and forced outages, but no aging factor). This is due to both CSQ transformers are still in a young age (22 years in service). However, when the year increases, the unavailability due to aging failures considerably increases and comes close to the traditional unavailability at the year 2015. The total unavailability (including all planned, forced and aging outages) therefore considerably increases when the age of transformers is getting older. Table 4 indicates that the EENS and EDC are not very significant as the CSQ substation is highly reliable as shown by the unavailability of 0.0088 hrs/yr in year 2006.

The results shown in Table 4 are based on the limited end-of-life data resulting in the mean life and standard deviation of 48.1 and 5.6 years respectively. There are only 3 transformers in a considered group, which were retired at a relatively similar period. This directly results in a narrow standard deviation (5.6 years). Even though the value of 5.6 was directly obtained using the real data, this data seems to be insufficient to represent the realistic uncertainty for the 230 kV transformer populations. The reliability analysis results in this case therefore tend to be too optimistic when involving aging failure uncertainty. For this reason, a U.S. end-of-life transformer source [6] was also used in this study for comparison purposes. Based on the report submitted to the U.S. Department of Energy [6], the end-of-life records for main power transformers during 1912 – 1982 indicated at 45 years of average service life (231 retired units out of the total 1087 units). The standard deviation was however not shown in the report, but it can be roughly approximated using the cumulative probability distribution provided in the report. The results show that the standard deviation for the transformers could be in a range of 15 – 17 years. This indicates that the uncertainty of end-of-life failure could be considerably greater than the results shown in Table 4 (S.D. = 5.6 years). The next section therefore investigates the impact of uncertainty due to the end-of-life failure using a sensitivity study.

4. Sensitivity Study on the End-of-Life Failure Uncertainty

The results shown in the previous section are based on the mean life of 48.1 years and the standard deviation of 5.6 years, and are designated as the Base Case in this section. Two additional scenarios are studied in this section and their results are compared against the Base Case. All the three cases are described as follows:

Base Case: Mean life = 48.1 years, standard deviation = 5.6 years.
Modified Case: Mean life = 48.1 years, standard deviation = 11.2 years.
U.S. Case: Mean life = 45.0 years, standard deviation = 17.0 years.

As previously noted, the standard deviation in the Base Case is relatively narrow due to a limited data and it might not be able to properly represent the aging failure uncertainty. In order to investigate the impact of the aging failure uncertainty, Modified Case is introduced by creating a wider standard deviation than that used in the Base Case. The standard deviation of 11.2 years (twice larger than the Base Case) is used in the Modified Case while the mean life is kept at the same value as the Base Case's (48.1 years). The end-of-life transformer data from [6] is used in the U.S. Case to represent another available data record that can be used for a comparison. The results of all the three cases are shown in Tables 5 – 7, and also pictorially presented in Figures 3 – 5.

Table 5: Unavailability (hrs/yr) of CSQ substation for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.0088	0.1185	10.7274
2007	0.0089	0.1751	13.6273
2008	0.0090	0.2591	17.0992
2009	0.0090	0.3794	21.2204
2010	0.0093	0.5504	26.0599
2011	0.0095	0.7862	31.6870
2012	0.0100	1.1147	38.2026
2013	0.0108	1.5599	45.6475
2014	0.0125	2.1572	54.1067
2015	0.0153	2.9451	63.6282

Table 6: Expected Energy Not supplied (MWh/yr) of CSQ substation for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.75	10.07	911.87
2007	0.85	16.65	1295.91
2008	0.90	26.03	1717.77
2009	0.92	38.79	2169.71
2010	0.95	56.68	2683.71
2011	0.99	81.83	3298.18
2012	1.06	117.25	4018.53
2013	1.12	161.71	4732.08
2014	1.31	226.12	5671.58
2015	1.58	304.07	6569.30

Table 7: Expected Damage Cost ($M/yr) of CSQ substation for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.002	0.030	2.736
2007	0.003	0.050	3.888
2008	0.003	0.078	5.153
2009	0.003	0.116	6.509
2010	0.003	0.170	8.051
2011	0.003	0.245	9.895
2012	0.003	0.352	12.056
2013	0.003	0.485	14.196
2014	0.004	0.678	17.015
2015	0.005	0.912	19.708

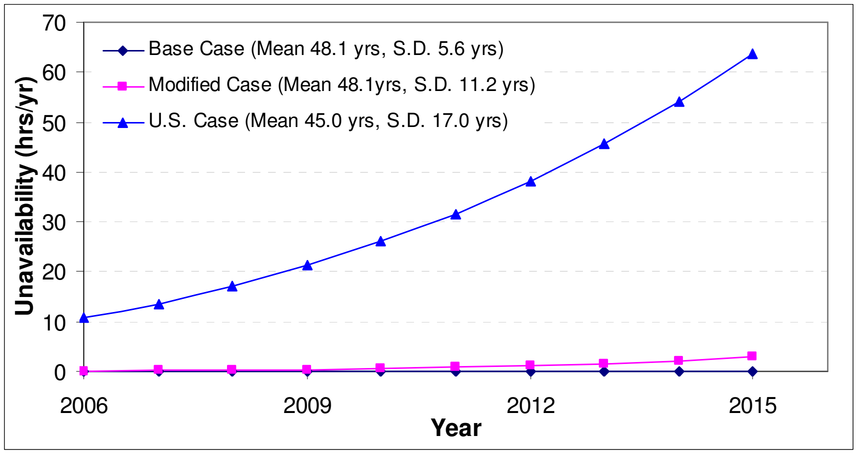

Figure 3: Unavailability of CSQ substation for three different scenarios.

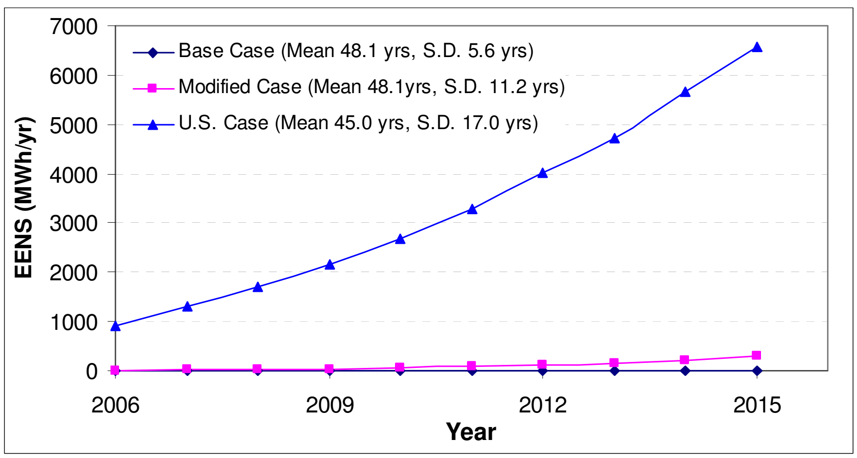

Figure 4: Expected Energy Not supplied of CSQ substation for three different scenarios.

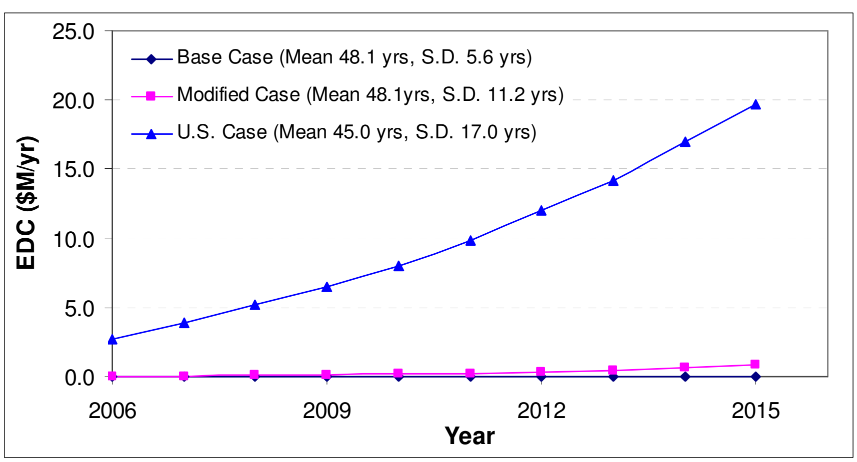

Figure 5: Expected Damage Cost of CSQ substation for three different scenarios.

Generally, Figures 3 – 5 indicate that the larger standard deviation basically creates more uncertainties and results in a less system reliability. As shown in Figure 3, the unavailability of the base case is very close to zero during the 10 years consideration. However, when the standard deviation is doubled (Modified Case), there is a considerable acceleration of the unavailability when the transformers get older. The unavailability for Modified Case increases to 2.945 hrs/yr in year 2015, which is approximately 193 times higher than that of the base case (0.015 hrs/yr in year 2015).

U.S. Case introduces the worst case scenario due to the relatively shorter mean life and larger standard deviation (more uncertainty). There is a significant acceleration of the system risk under this scenario throughout the 10 years consideration. The EENS and EDC in year 2015 can be expected at 6569.30 MWh/yr and 19.708 $M/yr respectively. This suggests that system reinforcement is needed for the case when the transformer mean life is short and standard deviation is large.

In conclusion, the results shown in Figures 3 – 5 indicate that the contribution of the aging failure to the system risk could be much more significant than the impact of planned and forced outages when the system components are considerably old. The mean life and standard deviation of the components play a very important role on the system risk. These factors could directly influence on a reinforcement project justification. The larger uncertain (a large standard deviation in this case) it is, the less reliable the system can be. The meaningful results and a confidence on decision making process, however, cannot be obtained without comprehensive end-of-life information. The accuracy and completeness of end-of-life component records are considerably prerequisite information in system reliability study particularly when considering aging failure impact.

5. CSQ Substation Reinforcement Study

This section presents a reliability analysis when an additional transformer is installed at the CSQ substation in order to reduce a potential system risk. The reinforced CSQ substation can be simply illustrated as shown in Figure 6.

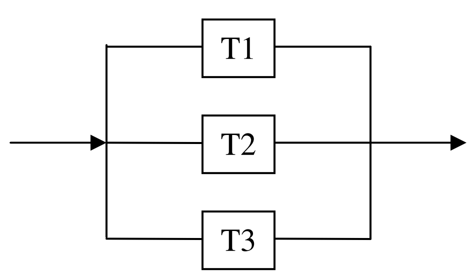

Figure 6: A parallel system representing three transformers at CSQ substation.

In Figure 6, a system will fail when all the three transformers are not in service. Assume that a transformer can be in a maintenance mode one at the time (no overlapping maintenance), and a new transformer to be added has no aging factor involved during the consideration period.

The general failure modes can be broadly categorized as follows:

Without Aging Factor:

1. One planned outage transformer and two forced outage transformers.
2. All three transformers are on forced outages.

With Aging Factor:

3. One planned outage transformer, one aging transformer and one forced outage transformer.
4. One aging outage TRF and two forced outage transformers.
5. Two aging outage transformers and one forced outage transformer.

The five general failure categories noted above are described in details and shown in Appendix A:

Equations (1) – (3) described earlier can be used to calculated reliability indices in this section. The three different cases from the sensitivity study section (Base Case, Modified Case and U.S. Case) are demonstrated again for a comparison purpose in this section. The reliability analysis results based on the three transformers (3 TRFs) are shown in Tables 8 – 10, and are also graphically presented in Figures 7 – 9 against with those results obtained using the two transformers (2 TRFs) illustrated in the previous section. The reinforcement project for the transformer addition is assumed to be completed at the beginning of year 2008. The three scenarios from the previous section are described again as follows:

Base Case: Mean life = 48.1 years, standard deviation = 5.6 years.
Modified Case: Mean life = 48.1 years, standard deviation = 11.2 years.
U.S. Case: Mean life = 45.0 years, standard deviation = 17.0 years.

Table 5: Unavailability (hrs/yr) of CSQ substation with the third transformer addition for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.000002	0.000065	0.003900
2007	0.000002	0.000090	0.004916
2008	0.000002	0.000126	0.006128
2009	0.000002	0.000176	0.007562
2010	0.000003	0.000244	0.009241
2011	0.000003	0.000336	0.011189
2012	0.000004	0.000462	0.013441
2013	0.000005	0.000628	0.016008
2014	0.000007	0.000849	0.018921
2015	0.000009	0.001136	0.022196

Table 6: Expected Energy Not supplied (MWh/yr) of CSQ substation with the third transformer addition for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.0001	0.0055	0.3548
2007	0.0002	0.0086	0.5050
2008	0.0002	0.0127	0.6716
2009	0.0002	0.0180	0.8525
2010	0.0003	0.0252	1.0612
2011	0.0003	0.0350	1.3142
2012	0.0004	0.0485	1.6155
2013	0.0005	0.0651	1.9215
2014	0.0007	0.0890	2.3285
2015	0.0009	0.1173	2.7295

Table 7: Expected Damage Cost ($k/yr) of CSQ substation with the third transformer addition for three different scenarios.

Year	Base Case	Modified Case	U.S. Case
2006	0.000	0.016	1.064
2007	0.001	0.026	1.515
2008	0.001	0.038	2.015
2009	0.001	0.054	2.558
2010	0.001	0.076	3.184
2011	0.001	0.105	3.943
2012	0.001	0.146	4.847
2013	0.001	0.195	5.764
2014	0.002	0.267	6.985
2015	0.003	0.352	8.188

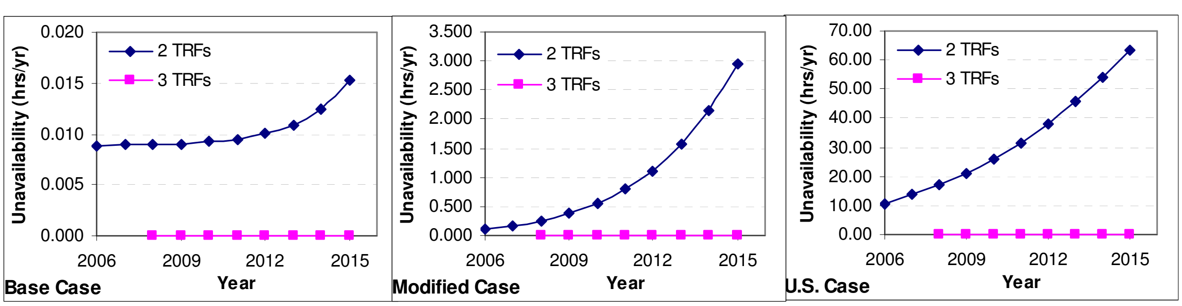

Figure 7: Unavailability (hrs/yr) of CSQ substation when considering two and three transformers for three different scenarios (Base Case, Modified Case and U.S. Case).

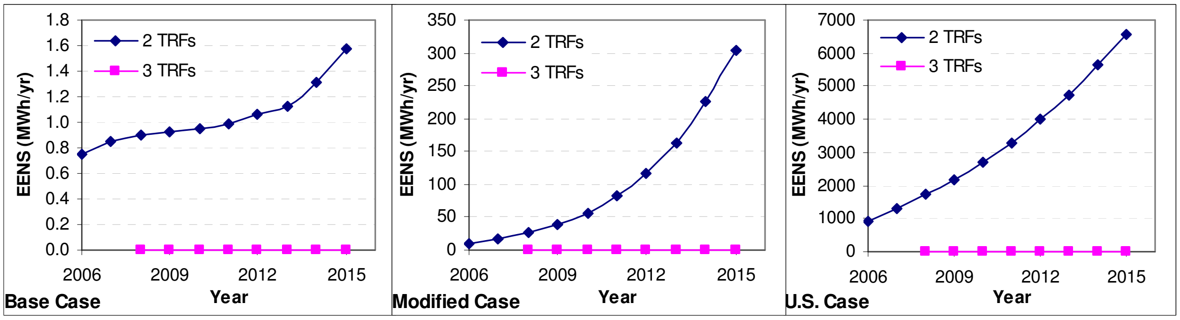

Figure 8: EENS (MWh/yr) of CSQ substation when considering two and three transformers for three different scenarios (Base Case, Modified Case and U.S. Case).

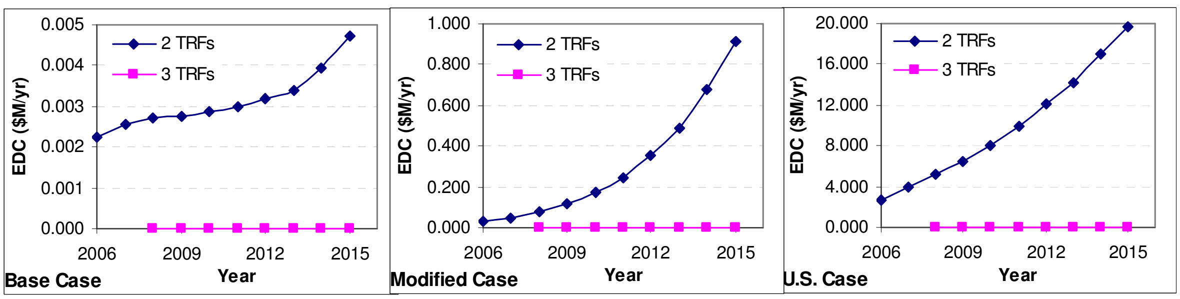

Figure 9: EDC ($M/yr) of CSQ substation when considering two and three transformers for three different scenarios (Base Case, Modified Case and U.S. Case).

Figures 7 – 9 indicate that there are very significant improvements on system reliability for all three cases when adding the third transformer to the substation. All the indices are very close to zero during the 10 years consideration when there are three transformers installed at the CSQ substation. This is due to the fact that there are two redundant transformers under a normal operation. In other word, if two transformers are out of service at the same time, the remaining unit alone is still able to supply the total load. The system risk due to aging failures after installing the third transformer is relatively very little and considerably insignificant during the next 10 years. The results for all the three cases after adding the third transformer at the CSQ substation are, therefore, relatively similar. The results shown in Figure 9 can be used to calculate a saving on customer monetary loss after installing the third transformer. This is addressed in the following section on cost/benefit analysis.

6. Reliability Cost/Benefit Analysis

This section conducts the reliability cost/benefit analysis for the three cases illustrated in the previous section.

Assume that:

- A discount rate is 6 %
- A useful life time for a transformer is 40 years
- A transformer addition project is $8 million

Capital return factor (CRF) = $\frac{0.06(1+0.06)^{40}}{(1+0.06)^{40}-1}$ = 0.06646

Annual investment cost (A) = (An actual investment)×CRF
= $M 8.0×0.06646 = 0.532 $M/year

Present value (PV) can be used to capture the time values of the costs during the system planning period (i.e. 10 years consideration).

In this case, $PV = A_j \sum_{j=1}^{m} \frac{1}{(1+0.06)^{j-1}}$, where: A_j = the annual cost in year j, m = system planning period.

A present value can also be applied to the expected damage cost (EDC), and expressed as follows [7]: $EDC = \sum_{j=1}^{m} \frac{EDC_j}{(1+0.06)^{j-1}}$.

6.1 GDP-Based Interruption Cost

As noted earlier, the unit interruption cost used in Sections 3 – 5 to calculate the expected damage cost (EDC) is based on the ratio of Provincial Gross Domestic Product (GDP) to the annual energy consumption. The rate is approximately 3.07 $/kWh in 2006. The unit interruption cost of 3.07 $/kWh used in this case represents an average monetary loss for the whole province without considering customer types and their impact contributions to the provincial economy. The cost/benefit analyses using GDP-based interruption cost for the three different cases (Base Case, Modified Case and U.S. Case) are summarized in Table 8.

Table 8: A summary of the cost/benefit analysis after a new transformer addition for the three cases.

Base Case: Mean life = 48.1 years, standard deviation = 5.6 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0.000
2007	0.000	0.502	0.000
2008	0.003	0.473	0.006
2009	0.003	0.447	0.007
2010	0.002	0.421	0.005
2011	0.002	0.398	0.005
2012	0.002	0.375	0.005
2013	0.002	0.354	0.006
2014	0.003	0.334	0.009
2015	0.003	0.315	0.010
Total	**0.020**	**4.151**	**0.005**

Modified Case: Mean life = 48.1 years, standard deviation = 11.2 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0.000
2007	0.000	0.502	0.000
2008	0.069	0.473	0.146
2009	0.097	0.447	0.217
2010	0.135	0.421	0.320
2011	0.183	0.398	0.460
2012	0.248	0.375	0.661
2013	0.323	0.354	0.913
2014	0.425	0.334	1.273
2015	0.540	0.315	1.715
Total	**2.020**	**4.151**	**0.487**

U.S. Case: Mean life = 45.0 years, standard deviation = 17.0 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0.000
2007	0.000	0.502	0.000
2008	4.580	0.473	9.683
2009	5.467	0.447	12.230
2010	6.369	0.421	15.128
2011	7.399	0.398	18.590
2012	8.494	0.375	22.651
2013	9.443	0.354	26.675
2014	10.678	0.334	31.970
2015	11.664	0.315	37.029
Total	**64.094**	**4.151**	**15.441**

As shown in Table 8, the total cost/benefit ratio over the 10 years planning period is very little (0.005) in the Base Case. Note that the project can be justified when the cost/benefit ratio is higher than 1.0. The Base Case result indicates that the project cannot be justified and therefore the new transformer should not be added during the planning consideration period (2006 – 2015). The total cost/benefit ratio in Modified Case is 0.487. This also indicates that the project cannot be justified at this present time. However, an annual cost/benefit ratio considerably increases in time. For example, the cost/benefit ratio is year 2014 is over 1. This indicates that the potential for a project justification can be achieved some year in the near future. An approximate time to add a new transformer is in year 2012 where the total cost/benefit ratio from years 2012 – 2015 becomes large than 1 (1.536/1.378 = 1.115). Generally speaking, a transformer addition under Modified Case can be deferred to some year in the future based on cost/benefit analysis. In U.S. Case, the total cost/benefit ratio is significantly higher than 1 (15.441). This indicates that the transformer addition project can be justified in year 2006 (i.e. project approved in year 2006 and an in service in year 2008) based on the unit interruption cost of 3.07 $/kWh.

It is very important to note that the cost/benefit analysis conducted in this section is based on the overall economic growth of the Province of B.C. The unit interruption cost of 3.07 $/kWh used in this case represents the average value for the whole province. Cathedral Square Substation is however serving Vancouver's main financial and commercial district, and supplying about 30% of all downtown loads. Loss of supply at the substation would have a significant impact on the customer monetary loss. The use of the average GDP-related rate as 3.07 $/kWh may not be able to satisfy this economic-sensitive location. An alternative model such as customer interruption cost survey for different customer sectors, i.e. commercial, industrial, and residential, may provide a better representation, and provide a distinctive monetary impact for the Vancouver's main financial and commercial loads. This alternative model considers an importance of different customer sectors in terms of their monetary impacts, and therefore could have an influence on the project justification particularly in Cathedral Square substation case. This customer-based survey interruption cost model is presented in the following section.

6.2 Customer-Based Survey 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 [8]. 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 [9]. This customer damage function is shown in Table 9. The customer damage functions shown in Table 9 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 10 [10].

Table 9: 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 10: 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**

Customer loads at Cathedral Square Substation compose of residential, commercial and industrial customer sectors. These three customer sector percentages are presented in Table 11.

Table 11: A customer load composition at Cathedral Square Substation.

Residential	Commercial	Industrial
2%	96%	2%

A composite unit interruption cost (Composite UIC) for Cathedral Square Substation can be calculated using the average unit interruption costs for three different customer sectors shown in Table 10 weighted by their sector percentages at Cathedral Square Substation, presented in Table 11. The Composite UIC calculation is shown as follows:

Composite UIC = $1.38 \times 0.02 + 36.70 \times 0.96 + 15.76 \times 0.02 = 35.57$ $/kWh

Obviously, the composite unit interruption cost for the Cathedral Square Substation is significantly large (35.57 $/kWh) due to the fact that the substation is dominated by the commercial customer sector, which is considerably sensitive to power outages.

The expected damage cost (EDC) obtained using customer-based survey interruption cost approach (Composite UIC = 35.57 $/kWh) is shown in Table 12.

Table 12: Expected Damage Cost ($M/yr) of CSQ substation associated with the two and three transformers considerations for three different scenarios.

Year	Two transformers (original)			Third transformer is added		
	Base Case	Modified Case	U.S. Case	Base Case	Modified Case	U.S. Case
2006	0.027	0.358	32.436	0.000	0.000	0.013
2007	0.030	0.593	46.096	0.000	0.000	0.018
2008	0.032	0.926	61.101	0.000	0.000	0.024
2009	0.033	1.380	77.176	0.000	0.001	0.031
2010	0.034	2.016	95.459	0.000	0.001	0.038
2011	0.035	2.911	117.316	0.000	0.001	0.047
2012	0.038	4.170	142.939	0.000	0.002	0.058
2013	0.040	5.752	168.320	0.000	0.002	0.069
2014	0.047	8.044	201.738	0.000	0.003	0.083
2015	0.056	10.816	233.670	0.000	0.004	0.097

Table 12 show that there are significant reductions on the expected interruption costs when the third transformer is installed. Magnitudes of cost reductions are, however, varied from case to case. This depends on the magnitudes of uncertainty incorporated. For example, the potential interruption cost reduction of U.S. Case (a largest uncertainty) is $M61.077 (61.101-0.024) in year 2008. The cost/benefit analysis used in the previous section can also be applied to obtain the cost/benefit ratio. The cost/benefit ratios for all the three cases using the customer-based survey interruption cost model are shown in Table 13.

Table 13: A summary of the cost/benefit analysis after a new transformer addition for the three cases using the customer-based survey interruption cost model.

Base Case: Mean life = 48.1 years, standard deviation = 5.6 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0.000
2007	0.000	0.502	0.000
2008	0.028	0.473	0.059
2009	0.028	0.447	0.063
2010	0.027	0.421	0.064
2011	0.026	0.398	0.065
2012	0.027	0.375	0.072
2013	0.026	0.354	0.073
2014	0.029	0.334	0.087
2015	0.033	0.315	0.105
Total	**0.224**	**4.151**	**0.054**

Modified Case: Mean life = 48.1 years, standard deviation = 11.2 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0.000
2007	0.000	0.502	0.000
2008	0.824	0.473	1.742
2009	1.158	0.447	2.591
2010	1.596	0.421	3.791
2011	2.174	0.398	5.462
2012	2.939	0.375	7.837
2013	3.824	0.354	10.802
2014	5.045	0.334	15.105
2015	6.400	0.315	20.317
Total	**23.960**	**4.151**	**5.772**

U.S. Case: Mean life = 45.0 years, standard deviation = 17.0 years.

Year	Reduction in EDC ($M/yr)	Present value of a new TRF ($M/yr)	Cost/Benefit Ratio
2006	0.000	0.532	0
2007	0.000	0.502	0
2008	54.359	0.473	114.924
2009	64.773	0.447	144.906
2010	75.583	0.421	179.532
2011	87.631	0.398	220.178
2012	100.726	0.375	268.603
2013	111.897	0.354	316.093
2014	126.521	0.334	378.805
2015	138.252	0.315	438.895
Total	**749.742**	**4.151**	**183.026**

Table 13 indicates that the transformer addition project still cannot be justified for the Base Case as the total cost/benefit ratio is still less than 1 (0.054). On the other hand, the cost/benefit ratio for the Modified Case is 5.772 when using the customer-based survey interruption cost model. This indicates that the third transformer should be added without delay (justified in year 2006 and in service in year 2008). In the U.S. Case, there is a significant cost/benefit ratio when adding the third transformer. This indicates that the project in this case should also immediately proceed.

In conclusion, both the Modified Case and U.S. Case can be justified when considering the unit interruption cost of 35.57 $/kWh (customer-based survey) in the cost/benefit analysis while the Base Case still cannot be justified. The reason for this is that the Base Case is relatively too optimistic due to a small standard deviation (less uncertainty) is used. Even though the mean life and standard deviation used in the Base Case are directly obtained from the actual data, these real data however are considerably insufficient. As previously noted, there are only three end-of-life transformers in this group, which all the three transformers were taken out of service at the similar time. This directly causes the narrow standard deviation (5.6 years), which seems to be too optimistic (too little uncertainty) based on the engineering judgement. This is the main reason to use the U.S. Case as a comparison. The mean life calculated from the BC and U.S. database are quite agreeable (48.1 and 45 years respectively), but the standard deviations are significantly different. The U.S. Case offers the worst case scenario due to the fact that a significant uncertainty (a standard deviation of 17 years) is incorporated. However, the U.S. Case is also based the actual data containing 231 end-of-life transformers in the record [6].

A compromise case is therefore introduced and designated as the Modified Case. The standard deviation used in the Modified Case is approximately the mid value between the standard deviations obtained from the BC and U.S. database. Consequently, the Modified Case is intended to overcome the weakness of the limited end-of-life transformer records used in the Base Case calculation, and the results obtained using the Modified Case are considered to be more realistic compared to the Base Case.

Based on the Modified Case, the cost/benefit ratio indicates that the transformer addition project should be deferred to year 2012 when using the GDP-Based interruption cost model (3.07 $/kWh). However, the cost/benefit ratio for the Modified Case when using the customer-based survey interruption cost approach (35.57 $/kWh) show that the project should be immediately implemented without delay. Even though, there are significant differences for the two cost models, the monetary loss impact on the Vancouver's main financial and commercial district due to power outages is more likely to follow the customer-based survey interruption cost model (35.57 $/kWh) rather than following the average GDP growth of the entire province. The use of the customer-based survey interruption cost approach in this particular case takes the monetary loss contributions for different customer sectors into account, which might be suite to present the monetary impact for the downtown loads.

7. Conclusions

The reliability study of the Cathedral Square Substation is conducted in this report. The results indicate that the contribution of the aging failure to the system risk could be much more significant than the impact of planned and forced outages when the system components are considerably old. The mean life and standard deviation of the components play a very important role on the system risk. These factors could directly influence on a reinforcement project justification. The cost/benefit analysis is also illustrated in this report using two different interruption cost models. One great difficulty found in this study in order to support in decision making process is underlie on the utilization of available reliability data as the information seems to be inadequate in particularly those related to end-of-life records. The meaningful results and a confidence on decision making process require the comprehensive end-of-life information in order to support and justify the project involving with aging failure concern. The accuracy and completeness of end-of-life component records are considerably prerequisite information in system reliability study particularly when considering aging failure impact.

The GDP-based interruption cost (3.07 $/kWh) provides an average value of monetary impact associated with power outages, and is insensitive to customer types and their contributions. On the other hand, the customer-based survey interruption cost (35.57 $/kWh for the CSQ Substation) is considerably sensitive to customer types and their contributions. If the power outage in downtown is a major concern due to its economic impact that can significantly drive the entire provincial economy, the customer-based survey interruption cost approach might be suitable in this particular case. Based on this study, if the mean life and standard deviation of the transformers are followed the Modified Case (48.1 years, 11.2 years respectively), the transmission addition project for the Cathedral Square Substation should be immediately implemented to reduce the potential of system risk under the customer-based survey interruption cost model. On the other hand, if the GDP-based interruption cost approach is used, the transmission addition project for the Modified Case could be deferred to year 2012.

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Appendix A:

The five basic failure categories for a parallel system consisting of the three transformers.

1.	**One planned outage transformer and two forced outage transformers.**		
1.1	T1 planned, then T2 forced, then T3 forced	$f_{p(1.1)} = f_3\left(\frac{r_2 r_1^p}{r_2 + r_1^p}\right) \times f_2\left(f_1^p r_1^p\right)$	$r_{p(1.1)} = \frac{r_3 r_2 r_1^p}{r_3 r_2 + r_2 r_1^p + r_3 r_1^p}$
1.2	T1 planned, then T3 forced, then T2 forced	$f_{p(1.2)} = f_2\left(\frac{r_3 r_1^p}{r_3 + r_1^p}\right) \times f_3\left(f_1^p r_1^p\right)$	$r_{p(1.2)} = \frac{r_3 r_2 r_1^p}{r_3 r_2 + r_2 r_1^p + r_3 r_1^p}$
1.3	T2 planned, then T1 forced, then T3 forced	$f_{p(1.3)} = f_3\left(\frac{r_1 r_2^p}{r_1 + r_2^p}\right) \times f_1\left(f_2^p r_2^p\right)$	$r_{p(1.3)} = \frac{r_3 r_1 r_2^p}{r_3 r_1 + r_1 r_2^p + r_3 r_2^p}$
1.4	T2 planned, then T3 forced, then T1 forced	$f_{p(1.4)} = f_1\left(\frac{r_3 r_2^p}{r_3 + r_2^p}\right) \times f_3\left(f_2^p r_2^p\right)$	$r_{p(1.4)} = \frac{r_3 r_1 r_2^p}{r_3 r_1 + r_1 r_2^p + r_3 r_2^p}$
1.5	T3 planned, then T1 forced, then T2 forced	$f_{p(1.5)} = f_2\left(\frac{r_1 r_3^p}{r_1 + r_3^p}\right) \times f_1\left(f_3^p r_3^p\right)$	$r_{p(1.5)} = \frac{r_2 r_1 r_3^p}{r_1 r_2 + r_1 r_3^p + r_2 r_3^p}$
1.6	T3 planned, then T2 forced, then T1 forced	$f_{p(1.6)} = f_1\left(\frac{r_2 r_3^p}{r_2 + r_3^p}\right) \times f_2\left(f_3^p r_3^p\right)$	$r_{p(1.6)} = \frac{r_2 r_1 r_3^p}{r_1 r_2 + r_1 r_3^p + r_2 r_3^p}$
2.	**All three transformers are on forced outages.**		
2.1	T1 forced, then T2 forced, then T3 forced	$f_{p(2.1)} = f_3\left(\frac{r_2 r_1}{r_2 + r_1}\right) \times f_2\left(f_1 r_1\right)$	$r_{p(2.1)} = \frac{r_3 r_2 r_1}{r_3 r_2 + r_2 r_1 + r_3 r_1}$
2.2	T1 forced, then T3 forced, then T2 forced	$f_{p(2.2)} = f_2\left(\frac{r_3 r_1}{r_3 + r_1}\right) \times f_3\left(f_1 r_1\right)$	$r_{p(2.2)} = \frac{r_3 r_2 r_1}{r_3 r_2 + r_2 r_1 + r_3 r_1}$
2.3	T2 forced, then T1 forced, then T3 forced	$f_{p(2.3)} = f_3\left(\frac{r_1 r_2}{r_1 + r_2}\right) \times f_1\left(f_2 r_2\right)$	$r_{p(2.3)} = \frac{r_3 r_1 r_2}{r_3 r_1 + r_1 r_2 + r_3 r_2}$
2.4	T2 forced, then T3 forced, then T1 forced	$f_{p(2.4)} = f_1\left(\frac{r_3 r_2}{r_3 + r_2}\right) \times f_3\left(f_2 r_2\right)$	$r_{p(2.4)} = \frac{r_3 r_1 r_2}{r_3 r_1 + r_1 r_2 + r_3 r_2}$
2.5	T3 forced, then T1 forced, then T2 forced	$f_{p(2.5)} = f_2\left(\frac{r_1 r_3}{r_1 + r_3}\right) \times f_1\left(f_3 r_3\right)$	$r_{p(2.5)} = \frac{r_2 r_1 r_3}{r_1 r_2 + r_1 r_3 + r_2 r_3}$
2.6	T3 forced, then T2 forced, then T1 forced	$f_{p(2.6)} = f_1\left(\frac{r_2 r_3}{r_2 + r_3}\right) \times f_2\left(f_3 r_3\right)$	$r_{p(2.6)} = \frac{r_2 r_1 r_3}{r_1 r_2 + r_1 r_3 + r_2 r_3}$
3.	**One planned outage TRF, one aging TRF and one forced outage TRF.**		
3.1	T1 planned, then T2 aging, then T3 forced	$f_{p(3.1)} = f_3\left(\frac{r_2^a r_1^p}{r_2^a + r_1^p}\right) \times f_2^a\left(f_1^p r_1^p\right)$	$r_{p(3.1)} = \frac{r_3 r_2^a r_1^p}{r_3 r_2^a + r_2^a r_1^p + r_3 r_1^p}$
3.2	T2 planned, then T1 aging, then T3 forced	$f_{p(3.2)} = f_3\left(\frac{r_1^a r_2^p}{r_1^a + r_2^p}\right) \times f_1^a\left(f_2^p r_2^p\right)$	$r_{p(3.2)} = \frac{r_3 r_1^a r_2^p}{r_3 r_1^a + r_1^a r_2^p + r_3 r_2^p}$

3.3	T3 planned, then T1 aging, then T2 forced	$f_{p(3.3)} = f_2\left(\frac{r_1^a r_3^p}{r_1^a + r_3^p}\right) \times f_1^a\left(f_3^p r_3^p\right)$	$r_{p(3.3)} = \frac{r_2 r_1^a r_3^p}{r_2 r_1^a + r_1^a r_3^p + r_2 r_3^p}$
3.4	T3 planned, then T2 aging, then T1 forced	$f_{p(3.4)} = f_1\left(\frac{r_2^a r_3^p}{r_2^a + r_3^p}\right) \times f_2^a\left(f_3^p r_3^p\right)$	$r_{p(3.4)} = \frac{r_1 r_2^a r_3^p}{r_1 r_2^a + r_2^a r_3^p + r_1 r_3^p}$
3.5	T1 forced, then T3 planned, then T2 aging	$f_{p(3.5)} = f_2^a\left(\frac{r_3^p r_1}{r_3^p + r_1}\right) \times f_3^p\left(f_1 r_1\right)$	$r_{p(3.5)} = \frac{r_2^a r_3^p r_1}{r_2^a r_3^p + r_3^p r_1 + r_2^a r_1}$
3.6	T2 forced, then T3 planned, then T1 aging	$f_{p(3.6)} = f_1^a\left(\frac{r_3^p r_2}{r_3^p + r_2}\right) \times f_3^p\left(f_2 r_2\right)$	$r_{p(3.6)} = \frac{r_1^a r_3^p r_2}{r_1^a r_3^p + r_3^p r_2 + r_1^a r_2}$
3.7	T3 forced, then T1 planned, then T2 aging	$f_{p(3.7)} = f_2^a\left(\frac{r_1^p r_3}{r_1^p + r_3}\right) \times f_1^p\left(f_3 r_3\right)$	$r_{p(3.7)} = \frac{r_2^a r_1^p r_3}{r_2^a r_1^p + r_1^p r_3 + r_2^a r_3}$
3.8	T3 forced, then T2 planned, then T1 aging	$f_{p(3.8)} = f_1^a\left(\frac{r_2^p r_3}{r_2^p + r_3}\right) \times f_2^p\left(f_3 r_3\right)$	$r_{p(3.7)} = \frac{r_1^a r_2^p r_3}{r_1^a r_2^p + r_2^p r_3 + r_1^a r_3}$
3.9	T1 planned, then T3 forced, then T2 aging	$f_{p(3.9)} = f_2^a\left(\frac{r_3 r_1^p}{r_3 + r_1^p}\right) \times f_3\left(f_1^p r_1^p\right)$	$r_{p(3.9)} = \frac{r_2^a r_3 r_1^p}{r_2^a r_3 + r_3 r_1^p + r_2^a r_1^p}$
3.10	T2 planned, then T3 forced, then T1 aging	$f_{p(3.10)} = f_1^a\left(\frac{r_3 r_2^p}{r_3 + r_2^p}\right) \times f_3\left(f_2^p r_2^p\right)$	$r_{p(3.10)} = \frac{r_1^a r_3 r_2^p}{r_1^a r_3 + r_3 r_2^p + r_1^a r_2^p}$
3.11	T1 aging, then T2 planned, then T3 forced	$f_{p(3.11)} = f_3\left(\frac{r_2^p r_1^a}{r_2^p + r_1^a}\right) \times f_2^p\left(f_1^a r_1^a\right)$	$r_{p(3.11)} = \frac{r_3 r_2^p r_1^a}{r_3 r_2^p + r_2^p r_1^a + r_3 r_1^a}$
3.12	T2 aging, then T1 planned, then T3 forced	$f_{p(3.12)} = f_3\left(\frac{r_1^p r_2^a}{r_1^p + r_2^a}\right) \times f_1^p\left(f_2^a r_2^a\right)$	$r_{p(3.12)} = \frac{r_3 r_1^p r_2^a}{r_3 r_1^p + r_1^p r_2^a + r_3 r_2^a}$
4.	**One aging outage TRF and two forced outage TRFs.**		
4.1	T1 forced, then T2 aging, then T3 forced	$f_{p(4.1)} = f_3\left(\frac{r_2^a r_1}{r_2^a + r_1}\right) \times f_2^a\left(f_1 r_1\right)$	$r_{p(4.1)} = \frac{r_3 r_2^a r_1}{r_3 r_2^a + r_2^a r_1 + r_3 r_1}$
4.2	T2 forced, then T1 aging, then T3 forced	$f_{p(4.2)} = f_3\left(\frac{r_1^a r_2}{r_1^a + r_2}\right) \times f_1^a\left(f_2 r_2\right)$	$r_{p(4.2)} = \frac{r_3 r_1^a r_2}{r_3 r_1^a + r_1^a r_2 + r_3 r_2}$
4.3	T3 forced, then T1 aging, then T2 forced	$f_{p(4.3)} = f_2\left(\frac{r_1^a r_3}{r_1^a + r_3}\right) \times f_1^a\left(f_3 r_3\right)$	$r_{p(4.3)} = \frac{r_2 r_1^a r_3}{r_2 r_1^a + r_1^a r_3 + r_2 r_3}$
4.4	T3 forced, then T2 aging, then T1 forced	$f_{p(4.4)} = f_1\left(\frac{r_2^a r_3}{r_2^a + r_3}\right) \times f_2^a\left(f_3 r_3\right)$	$r_{p(4.4)} = \frac{r_1 r_2^a r_3}{r_1 r_2^a + r_2^a r_3 + r_1 r_3}$
4.5	T1 aging, then T2 forced, then T3 forced	$f_{p(4.5)} = f_3\left(\frac{r_2 r_1^a}{r_2 + r_1^a}\right) \times f_2\left(f_1^a r_1^a\right)$	$r_{p(4.5)} = \frac{r_3 r_2 r_1^a}{r_3 r_2 + r_2 r_1^a + r_3 r_1^a}$
4.6	T2 aging, then T1 forced, then T3 forced	$f_{p(4.6)} = f_3\left(\frac{r_1 r_2^a}{r_1 + r_2^a}\right) \times f_1\left(f_2^a r_2^a\right)$	$r_{p(4.6)} = \frac{r_3 r_1 r_2^a}{r_3 r_1 + r_1 r_2^a + r_3 r_2^a}$

5.	**Two aging outage TRFs and one forced outage TRF.**		
5.1	T1 aging, then T2 aging, then T3 forced	$f_{p(5.1)} = f_3\left(\dfrac{r_2^a r_1^a}{r_2^a + r_1^a}\right) \times f_2^a\left(f_1^a r_1^a\right)$	$r_{p(5.1)} = \dfrac{r_3 r_2^a r_1^a}{r_3 r_2^a + r_2^a r_1^a + r_3 r_1^a}$
5.2	T2 aging, then T1 aging, then T3 forced	$f_{p(5.2)} = f_3\left(\dfrac{r_1^a r_2^a}{r_1^a + r_2^a}\right) \times f_1^a\left(f_2^a r_2^a\right)$	$r_{p(5.2)} = \dfrac{r_3 r_1^a r_2^a}{r_3 r_1^a + r_1^a r_2^a + r_3 r_2^a}$
5.3	T3 forced, then T1 aging, then T2 aging	$f_{p(5.3)} = f_2^a\left(\dfrac{r_1^a r_3}{r_1^a + r_3}\right) \times f_1^a\left(f_3 r_3\right)$	$r_{p(5.3)} = \dfrac{r_2^a r_1^a r_3}{r_2^a r_1^a + r_1^a r_3 + r_2^a r_3}$
5.4	T3 forced, then T2 aging, then T1 aging	$f_{p(5.4)} = f_1^a\left(\dfrac{r_2^a r_3}{r_2^a + r_3}\right) \times f_2^a\left(f_3 r_3\right)$	$r_{p(5.4)} = \dfrac{r_1^a r_2^a r_3}{r_1^a r_2^a + r_2^a r_3 + r_1^a r_3}$
5.5	T1 aging, then T3 forced, then T2 aging	$f_{p(5.5)} = f_2^a\left(\dfrac{r_3 r_1^a}{r_3 + r_1^a}\right) \times f_3\left(f_1^a r_1^a\right)$	$r_{p(5.5)} = \dfrac{r_2^a r_3 r_1^a}{r_2^a r_3 + r_3 r_1^a + r_2^a r_1^a}$
5.6	T2 aging, then T3 forced, then T1 aging	$f_{p(5.6)} = f_1^a\left(\dfrac{r_3 r_2^a}{r_3 + r_2^a}\right) \times f_3\left(f_2^a r_2^a\right)$	$r_{p(5.6)} = \dfrac{r_1^a r_3 r_2^a}{r_1^a r_3 + r_3 r_2^a + r_1^a r_2^a}$